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LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a] Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b] Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c] Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d] Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e] Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in

temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

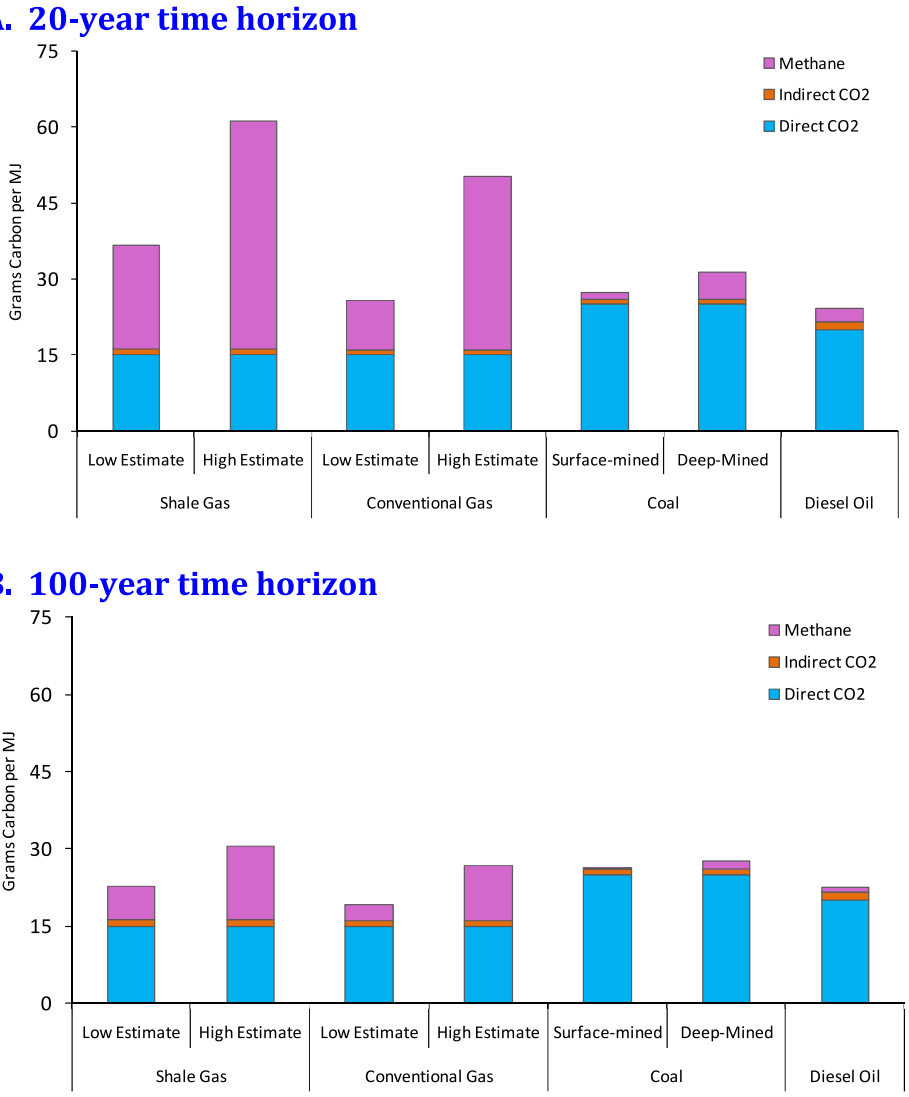

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly

reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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Life cycle greenhouse gas emissions of Marcellus shale gas

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Abstract
This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas

S Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding

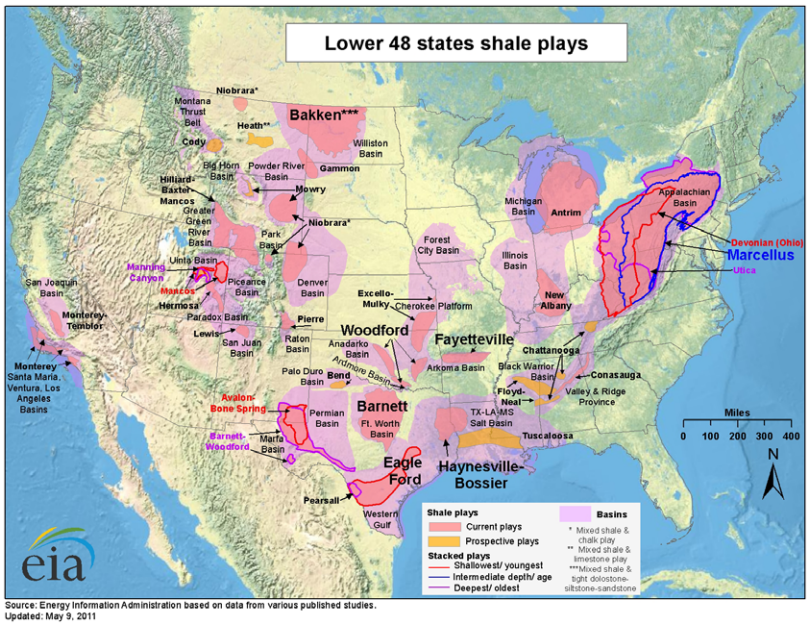

Figure 1. Shale gas plays and basins in the 48 states (source: US Energy Information Administration 2011a, available at http://www.eia.gov/oil_gas/rpd/shale_gas.jpg).

natural gas use including increased natural gas fired electricity generation, use as an alternative transportation fuel, and even exporting as liquefied natural gas. To date most shale gas activity has been in the Barnett shale in Texas. However, the immense potential of the Marcellus shale has stimulated increased attention. The shale play has an estimated gas-in-place of 1500 Tcf or 42 000 Mm^3, of which 262–500 Tcf or 7400–14 000 Mm^3 are thought to be recoverable (Hill *et al* 2004, US DOE 2009).

Advancements in horizontal drilling and hydraulic fracturing, demonstrated successfully in the Barnett shale and first applied in the Marcellus shale in 2004, have enabled the recovery of economical levels of Marcellus shale gas. After vertical drilling reaches the depth of the shale, the shale formation is penetrated horizontally with lateral lengths extending thousands of feet to ensure maximum contact with the gas-bearing seam. Hydraulic fracturing is then used to increase permeability that in turn increases the gas flow.

In this study, life cycle greenhouse gas (GHG) emissions associated with the Marcellus shale gas production are estimated. The difference between GHG emissions of natural gas production from unconventional Marcellus gas wells and average domestic wells is considered to help determine the environmental impacts of the development of shale gas resources. The results of this analysis are compared with life cycle GHG emissions of average domestic natural gas pre-Marcellus and imported liquefied natural gas. In addition domestic coal and Marcellus shale for electricity generation are compared. Other environmental issues may also be of concern in the Marcellus shale development, including disruption of natural habitats, the use of water and creation of wastewater as well as the impacts of truck transport in rural areas. However these environmental issues are outside the scope of our analysis and are not addressed in this paper.

In estimating GHG emissions, we include GHG emissions of carbon dioxide, methane and nitrous oxide. We converted the GHG emissions to carbon dioxide equivalents according to the global warming potential (GWP) factors reported by IPCC. We use the 100-year GWP factor, in which methane has a global warming potential (GWP) 25 times higher than carbon dioxide (IPCC 2007).

2. Marcellus shale gas analysis boundaries and functional unit

The boundary of our analysis and the major process steps included in our estimates are shown in figure 2. Final life cycle emission estimates are reported in grams of carbon dioxide equivalent emissions per megajoule of natural gas (g CO_2e/MJ) produced. Each of the individual processes in the natural gas life cycle has an associated upstream supply chain and is included in this study to provide a full assessment of GHG emissions associated with Marcellus shale gas. The sources of GHG emissions considered in the LCA include: emissions from the production and transportation of material involved in the well development activities (such as trucking water); emissions from fuel consumption for powering the drilling and fracturing equipment; methane leaks and fuel combustion emissions associated with gas production, processing, transmission, distribution, and natural gas combustion.

The life cycle of Marcellus shale natural gas begins with a 'preproduction phase' that includes the well site investigation, preparation of the well pad including grading and construction of the well pad and access roads, drilling, hydraulic fracturing, and well completion (Soeder and Kappel 2009). After this preproduction phase is completed, the well becomes operational and starts producing natural gas. This natural gas can require additional processing to remove water, CO_2 and/or

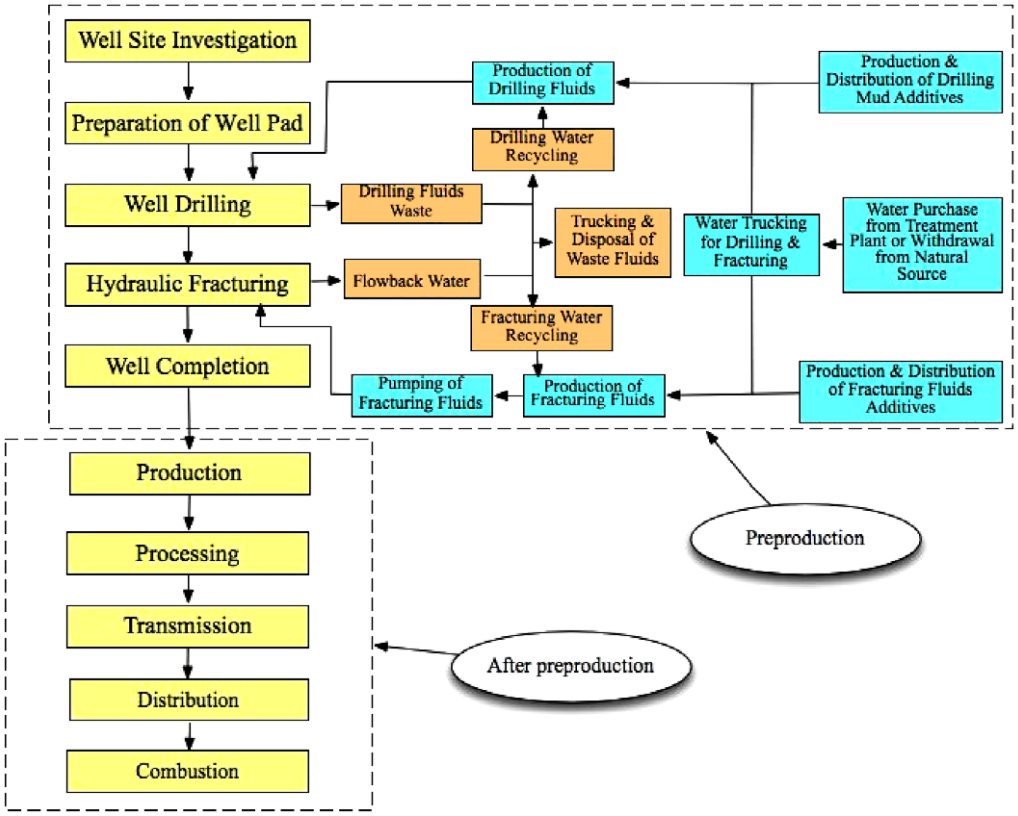

Figure 2. Analysis boundaries and gas production processes.

natural gas liquids before it enters the natural gas transmission and distribution system, which delivers it to final end users. For this work we assume that the GHG emissions for production, transmission, distribution and combustion of Marcellus shale natural gas are similar to average domestic gas sources as estimated by Jaramillo *et al* (2007) and further developed and updated by Venkatesh *et al* (2011).

Finally, natural gas has many current and potential uses including electricity generation, chemical feedstock, and as a transportation fuel. Modeling these uses allows comparisons of different primary energy sources. Here we model its use for power generation since it is the largest single use of natural gas in the US (US EIA 2011a, 2011b).

As previously mentioned, this study integrates GHG emissions from the life cycle of water associated with Marcellus shale gas production. Large amounts of water are consumed in the drilling and hydraulic fracturing processes (preproduction phase). Hydraulic fracturing uses fluid pressure to fracture the surrounding shale. The fracturing fluid consists of water mixed with a number of additives necessary to successfully fracture the shale seam. The source of the water varies and can be surface or ground water, purchased from a local public water supplier, or reused fracturing water. In this study we assume 45% of the water is reused on site and the original sources are surface water (50%) and purchased from a local water treatment plant (50%). Regardless of the water source used to produce the hydraulic fracturing fluid, trucks transport the water for impoundment at the well pad. In addition, flowback water (hydraulic fracturing fluid that returns to the surface) and produced water must be trucked to the final disposal site. This water is assumed to be disposed of via deep well injection. A detailed description of the method and data sources used to estimate the GHG emissions associated with all these stages is presented in section 3.

Marcellus shale gas production is in its infancy. Thus, industry practice is evolving and even single well longevity is unknown. Assumptions related to production rates and ultimate recovery have considerable uncertainty. Below, we include a sensitivity analysis for a wide range of inputs parameters.

This study does not consider any GHG emissions outside of the Marcellus shale gas preproduction and production processes. Natural processes or development actions such as hydraulic fracturing might lead to emissions of the shale gas external to a well, particularly in the case of poorly installed well casings (Osborn *et al* 2011). Any such external leaks are not included in this study.

3. Methods for calculating life cycle greenhouse gas emissions

Our study used a hybrid combination of process activity emission estimates and economic input–output life cycle assessment estimates to estimate the preproduction GHG emission estimates (Hendrickson *et al* 2006, CMU GDI 2010). Emissions from production, processing and transport were adapted from the literature. We include emissions estimates based on different data sources and reasonable

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. Emissions from Marcellus shale gas preproduction

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

extensive sensitivity analysis over a range of flow rates and well lifetimes, as discussed below.

The EIO-LCA (CMU GDI 2010) model was used to estimate GHG emissions from the construction of the access road and the multi-well pad. These costs were estimated using the utility price cost estimation method (RSMeans 2005). The size of an average Marcellus well pad is reported as being between 2 and 6 acres and typically between 4 and 5 acres (16 000 and 20 000 m^2) during drilling and fracturing phase (NY DEC 2009, Columbia University 2009). The costs of constructing this pad are estimated to be \$3.0–\$3.3 million per well pad in 2002 dollars (see the supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail). Using these costs as input, GHG emissions associated with well pad construction are estimated with the EIO-LCA (CMU GDI 2010) model.

Greenhouse gas emissions associated with drilling operations were calculated by two methods; (1) using the drilling energy intensity (table 1) and the life cycle diesel engine emissions factor of 635 g CO_2e per hp–hr output (Sheehan *et al* 2000), and (2) using drilling cost data and the EIO-LCA model (CMU GDI 2010). The EIA estimated the average drilling cost for natural gas wells in 2002 to be \$176 per foot (including the cost for drilling and equipping the wells and for surface producing facilities) (US EIA 2008). Emissions associated with the production of the drilling mud components were based on data from the SimaPro life cycle tool and the EIO-LCA economic model (PRé Consultants 2007, CMU GDI 2010).

Hydraulic fracturing associated GHG emissions result from the operation of the diesel compressor used to move and compress the fracturing fluid to high pressure, the emissions associated with the production of the hydraulic fracturing fluid, and from fugitive methane emissions as flowback water is captured. The last category of emissions is discussed separately below. Energy and emissions associated with the hydraulic fracturing process were modeled by using vendor specific diesel data along with the emission factor described above. The emissions of hydraulic fracturing fluid production are estimated with EIO-LCA model, based on the price of additives and fracturing fluid composition (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail).

There may be significant GHG emissions as a result of flaring and venting activities that occur during well casing and gathering equipment installation. The natural gas associated with the hydraulic fracturing flowback water is flared and vented. Flaring is used for testing the well gas flow prior to the construction of the gas gathering system which transport the gas to the sales line. Well completion emissions depend on the flaring/venting time, gas flow rate during well completion, the ratio of flaring to venting, and flaring efficiency. Uncertainty/variability analysis was conducted to investigate the effect of flaring/venting time, gas flow rate during fracturing water flowback, and flaring per cent on the well completion emissions. For those well completions with the collection facilities in place, gas is flared for between 12 and 24 h, due to necessary flowback operations. In wells where the appropriate gas gathering system as a tie to the gas sales line is not available for the gas during fracturing water flowback, the flaring or venting can occur for between 4 and 15 days as shown in table 2 (NY DEC 2009). In our model, we assumed the gas release rate during well completion equals the initial 30 day gas production rate for the base case and considered a scenario with both venting and flaring (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for details).

3.2. Emissions from Marcellus shale gas production to combustion

GHG emissions for production, processing, transmission, distribution and combustion of Marcellus shale natural gas are assumed to be similar to the US average domestic gas system that have been estimated previously (Jaramillo *et al* 2007). Jaramillo *et al* (2007) estimates were updated to include the uncertainty and variability in life cycle estimates and recalculated with recent and/or more detailed information by Venkatesh *et al* (2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. Methane leakage rates throughout the natural gas system (excluding the preproduction processes previously discussed) are a major concern and our analysis has an implied fugitive emissions rate of 2%, consistent with the EPA natural gas industry study (US EPA 1996, 2010).

Venkatesh *et al* (2011) estimated the mean emission factors used in this study: 9.7 g CO_2e/MJ of natural gas in production; 4.3 g CO_2e MJ for processing; 1.4 g CO_2e/MJ for transmission and storage; 0.8 g CO_2e/MJ for distribution; and 50 g CO_2e/MJ for combustion.

3.3. Emissions associated with the life cycle of water used for drilling and hydraulic fracturing

Water resource management is a critical component of the production of Marcellus shale natural gas. Chesapeake Energy (2010) indicates that 100 000 gallons of water are used for drilling mud preparation. Two to six million gallons of water per well are required for the hydraulic fracturing process (Staaf and Masur 2009). About 85% of the drilling mud is reused (URS Corporation 2010). The flowback and recycling rates are used to estimate the total volume of water required. About 60–65% of this hydrofracturing fluid is recovered (URS Corporation 2010). For the flowback water, a recycle rate from 30 to 60% can be achieved (Agbaji *et al* 2009). The rest of the flowback water is temporarily stored in the impoundment and transported off site for disposal. Base case assumptions for these parameters are shown in table 2.

Emissions associated with drilling water use and hydraulic fracturing water use result from water taken from surface water resources or a local public water system; truck transport to the well pad, and then from the pad to disposal via deep well injection. It is assumed that no GHG emissions are related

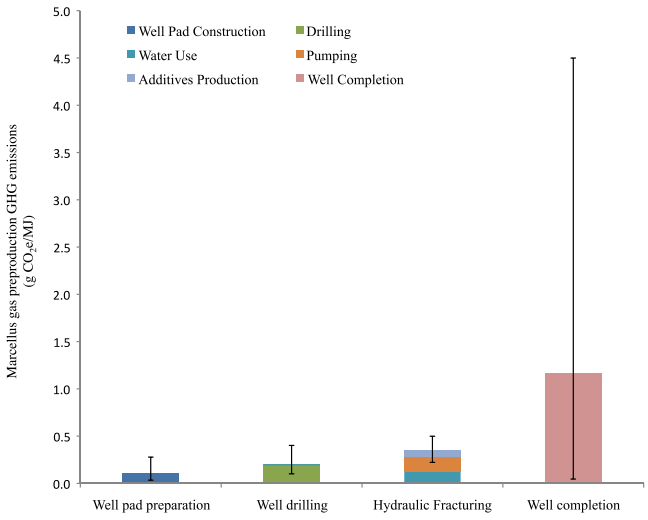

Figure 3. GHG emissions from different stages of Marcellus shale gas preproduction.

with producing water if it comes from surface water resources. For the water purchased from a local public water system, the emission factor for water treatment is used, which is estimated to be 3.4 g CO_2e/gallon of water generated according to Stokes and Horvath (2006). The energy intensity for transportation of liquids via truck is assumed to be 1028 Btu/ton mile for both forward and back-haul trips, as given in the GREET model (Wang and Santini 2009). In this study we assume that separate round trips are needed to transport the freshwater to the pad and to remove wastewater to the disposal site. This is to say that trucks bring in the freshwater from the source and return to the source empty; trucks also collect the wastewater from the well site and return to the well site empty. The life cycle emission factor (wells to wheels) for diesel as a transportation fuel is 93 g CO_2e/MJ (Wang and Santini 2009).

To estimate transport emissions associated with water taken from surface streams and water purchased from the local public water system, we used spatial analysis (ArcGIS) to estimate the distance from the surface water source to the well pad using well operational data and geographical information from Pennsylvania Department of Environmental Protection (2010). We depicted the overall distribution pattern of Marcellus wells under drilling and production in PA and NY in June 2010 by GIS. The distance from the well site to the surface water source is assumed to be 5 miles or 8 km in the base case of the model and the same transportation distance is also assumed for the water purchased from local public water system. We assumed an equal probability for sourcing water between surface water and the local public water system.

The trucking distance between well site and deep well injection facility was also estimated by GIS (PA DEP 2010). The average value of 80 miles or 130 km as determined by GIS was used in the base case.

4. Results for the base case

A total of 5500 t CO_2e is emitted during 'preproduction' per well. This is equivalent to 1.8 g CO_2e/MJ of natural gas produced over the lifetime of the well. Figure 3 depicts the GHG emissions by preproduction stage and by source. As can be seen, the completion stage has the largest GHG emissions, which result from flaring and/or venting. The error bars represent the limits of the 90% confidence interval of the emissions from each stage based on the uncertainty analysis.

A recent EPA report addressing emissions from the natural gas industry reported that 177 t of CH_4 is released during the completion of an unconventional gas well (US EPA 2010). This estimate is consistent with the analysis here and falls within the range estimated by our study, 26–1000 t of CH_4 released per completion and a mean value of 400 t of CH_4 released per completion. In our model, this methane released during the well completion is either flared with a combustion efficiency of 98% or vented without recovery.

Adding the preproduction emissions estimate to the downstream emission estimated by Venkatesh *et al* (2011) results in an overall GHG emissions factor of 68 g CO_2e/MJ of gas produced (figure 4). The life cycle emissions are dominated by combustion that accounts for 74% of the total emissions.

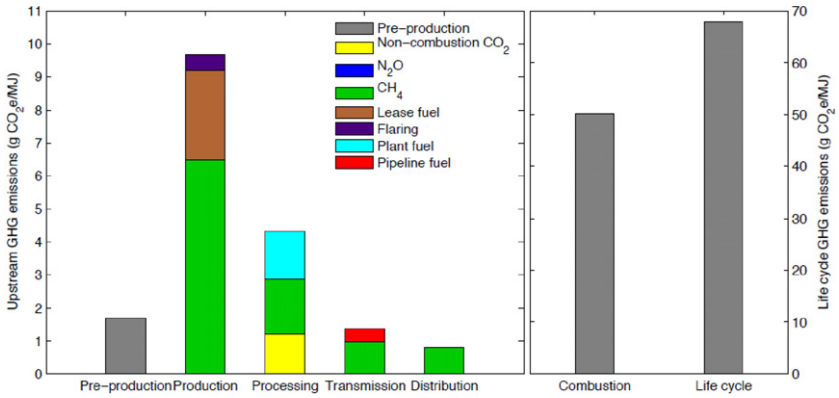

Figure 4. GHG emissions through the life cycle of Marcellus shale gas. (Preproduction through distribution emissions are on left scale; combustion and total life cycle emissions are on right scale. No carbon capture is included after combustion.)

Table 3. Uncertainty analysis on Marcellus gas preproduction.

Life cycle stage	Mean (g CO_2e/MJ)	Standard deviation (g CO_2e/MJ)	COV	90% CI-L (%)	90% CI-U (%)
Well pad preparation	0.13	0.1	0.72	58	131
Drilling	0.21	0.1	0.50	51	95
Hydraulic fracturing	0.35	0.1	0.24	37	42
Completion	1.15	1.8	1.53	96	287
Total	1.84	1.8	0.96	67	179

Table 4. Sensitivity of emissions from wells with different production rates and lifetimes. (Source: author calculations.)

Average gas flow (MMscf/day)	Lifetime (years)	Emissions from preproduction (g CO_2e/MJ)	Preproduction % contribution to life cycle emissions of Marcellus shale gas (%)	Total life cycle emissions (g CO_2e/MJ)
10	25	0.1	0.1	65.3
10	10	0.1	0.2	65.3
10	5	0.3	0.4	65.5
3	25	0.2	0.3	65.4
3	10	0.5	0.7	65.7
3	5	0.9	1.4	66.1
1	25	0.6	0.8	65.8
1	10	1.4	2.1	66.6
1	5	2.8	4.1	68.0
0.3	25	1.8	2.7	67.0
0.3	10	5	6.6	69.8
0.3	5	9.2	12.4	74.4

5. Sensitivity and uncertainty

Our results are subject to considerable uncertainty, particularly for the production rates and well lifetime. Table 3 summarizes the uncertainty analysis on the emission estimates for preproduction based on the distribution of parameters used.

Table 4 addresses model sensitivity to different estimates of ultimate gas recovery from wells, investigating the impact of different production rates and lifetimes. At high production rates and long well lifetimes the preproduction GHG emissions are normalized over higher volumes of natural gas than when using low flow rates and short well lifetimes. Comparing the case of 10 MMscf/day with a 25-year well lifetime to 0.3 MMscf/day with a 5-year well lifetime, table 4 shows that the emissions go from 0.1 to 9.2 g CO_2e/MJ. The overall life cycle emissions change from 65 to 74 g CO_2e/MJ. However, the preproduction emissions are less than 15% of the total life cycle emissions in all cases.

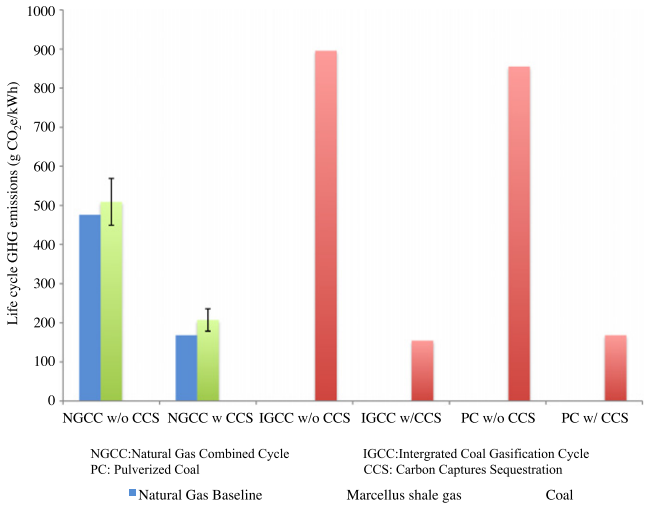

Figure 5. Comparison of life cycle GHG emissions from current domestic natural gas, Marcellus shale gas and coal for use in electricity production.

6. Comparison with coal for power generation

Marcellus shale gas emissions can be compared to alternative energy sources and processes when using a common metric such as electricity generated. Currently coal power plants are used to generate base load. Natural gas power plants, especially inefficient ones, are used to provide regulation services to balance supply and demand at times when base load power plants are insufficient or there is high-frequency variability in load or from renewable resources. Natural gas combined cycle (NGCC) plants could be used to generate base load thus competing directly with coal to provide this service. For this reason our comparison includes the emissions associated with using Marcellus shale gas in a NGCC power plant (efficiency of 50%) and the emissions from using coal in pulverized coal (PC) plants (efficiency of 39%) and integrated gasification combined cycle (IGCC) plants (efficiency of 38%). The results of these comparisons can be seen in figure 5. For this comparison point values are used for the life cycle GHG emissions of coal-based electricity. The error bars found in figure 5 represent the low and high emissions values for Marcellus shale gas, based on the assumptions of well production rate and well lifetime. The high-emission scenario assumes a 5-year well with 0.3 MMscf/day production rate

while the low-emission scenario, assumes a 25-year well with 10 MMscf/day production rate. Also shown in figure 5 are the life cycle emissions of electricity generated in power plants with carbon capture and sequestration (CCS) capabilities (efficiency of 43% for NGCC with CCS; efficiency of 30% for PC with CCS; efficiency of 33% for ICGG with CCS).

In general, natural gas provides lower greenhouse emission for all cases studied whether the gas is derived from Marcellus shale or the average 2008 domestic natural gas system. When advanced technologies are used with CSS then the emissions are similar and coal provides slightly less emissions. This implies that the upstream emissions for natural gas life cycle are higher than the upstream emissions from coal, once efficiencies of power generation are taken into account (Jaramillo *et al* 2007).

The comparison of natural gas and coal for electricity allows us to investigate the impact of three additional model uncertainty components including the choice of leakage rate, GWP values, and re-refracking of a Marcellus gas well. This study assumes a 2% production phase leakage rate based on the volume of gas produced (US EPA 2010, Venkatesh *et al* 2011). Assuming the average efficiency of 43% for natural gas fired electricity generation and 32% for coal fired plants the fugitive emissions rate would need to be 14% (resulting in a life cycle emission factor for Marcellus gas of 125 g CO_2e/MJ) before the overall life cycle emissions including those of electricity generation would be greater than coal. This is an exorbitantly high leakage rate and to put it into perspective, using 2009 dry natural gas production estimates and the average wellhead price, we calculate that the economic losses a would total around $11 billion. If we convert our data to the 20-year GWP the break-even point is reduced to 7% because of the higher impacts attributed to methane. Finally, we modeled a single hydraulic fracturing event occurring during well preproduction (figure 3). Above we calculated that the break-even emission factor that would make coal and natural electricity generation the same is 125 g CO_2e/MJ of natural gas. With the current emissions estimate for Marcellus gas of 68 g CO_2e/MJ, and a hydraulic fracturing event (and its associated flaring and venting emissions) contributing 1.5 g CO_2e/MJ to this estimate, more than 25 fracturing events would need to occur in a single well before the decision between coal and natural gas would change.

7. Comparison with liquefied natural gas as a future source

In 2005 EIA suggested that domestic natural gas production and Canadian imports would decline as natural gas consumption increased. EIA predicted that liquefied natural gas (LNG) imports would grow to offset the deficits in North American production (US EIA 2011a, 2011b). As a result of the development of unconventional natural gas reserves, EIA has changed their projections. The Annual Energy Outlook 2011 reference case (US EIA 2011a, 2011b) predicts that increases in shale gas production, including Marcellus, will more than offset the decline in conventional natural gas and decreasing imports from Canada and will allow for increases in natural gas consumption. Since shale gas is projected to be the largest component of the unconventional sources of future natural gas production, it seem appropriate to compare its emissions to those of the gas that would be used if shale gas were not produced. Venkatesh *et al* (2011) estimated the life cycle GHG from LNG imported to the US to have a mean of 70 g CO_2e/MJ, These results are based on emissions due to production and liquefaction in the countries of origin, shipping the gas to the US by ocean tanker, regasification in the US and its transmission, distribution and subsequent combustion. On average, the emissions of Marcellus shale gas were about 3% lower than LNG. As with the overall Marcellus gas results, there is considerable uncertainty to the comparisons. However, we conclude that as these unconventional sources of natural gas supplant LNG imports, overall emissions will not rise.

8. Conclusion

The GHG emission estimates shown here for Marcellus gas are similar to current domestic gas. Other shale gas plays could generate different results considering regional environmental variability and reservoir heterogeneity. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus gas preproduction. These preproduction emissions, however, are not substantial contributors to the life cycle estimates, which are dominated by the combustion emissions of the gas. For comparison purposes, Marcellus shale gas adds only 3% more emissions to the average conventional gas, which is likely within the uncertainty bounds of the study. Marcellus shale gas has lower GHG emissions relative to coal when used to generate electricity.

Acknowledgments

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States

Timothy J. Skone, P.E.

Office of Strategic Energy Analysis and Planning

May 12, 2011

Presented at: Cornell University Lecture Series

U.S. DEPARTMENT OF ENERGY

Overview

1. Who is NETL?
2. What is the role of natural gas in the United States?
3. Who uses natural gas in the U.S.?
4. Where does natural gas come from?
5. What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?
6. How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?
7. What are the opportunities for reducing GHG emissions?

Question #1:

Who is NETL?

National Energy Technology Laboratory

MISSION

Advancing energy options to fuel our economy, strengthen our security, and improve our environment

Oregon

Pennsylvania

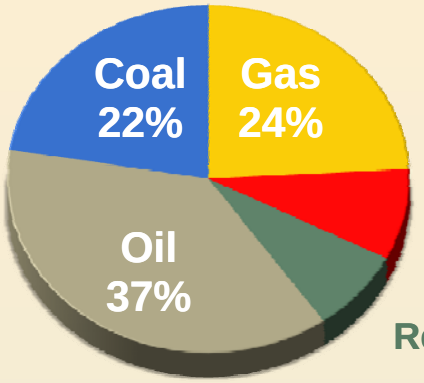
West Virginia

Question #2:

What is the role of natural gas in the United States?

Energy Demand 2008

100 QBtu / Year
84% Fossil Energy



Nuclear
8%

Renewables
8%

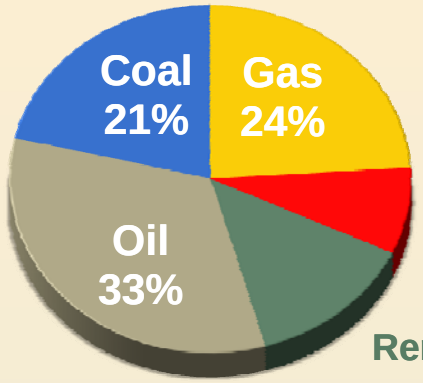
5,838 mmt CO_2

+ 14%

United States

Energy Demand 2035

114 QBtu / Year
78% Fossil Energy

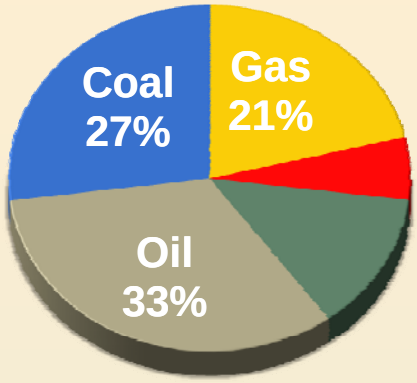


Nuclear
8%

Renewables
14%

6,311 mmt CO_2

487 QBtu / Year
81% Fossil Energy



Nuclear
6%

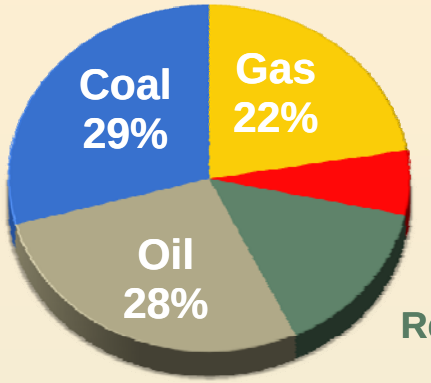
Renewables*
13%

29,259 mmt CO_2

+ 47%

World

716 QBtu / Year
79% Fossil Energy



Nuclear
8%

Renewables*
15%

42,589 mmt CO_2

Sources: U.S. data from EIA, Annual Energy Outlook 2011; World data from IEA, World Energy Outlook 2010, Current Policies Scenario

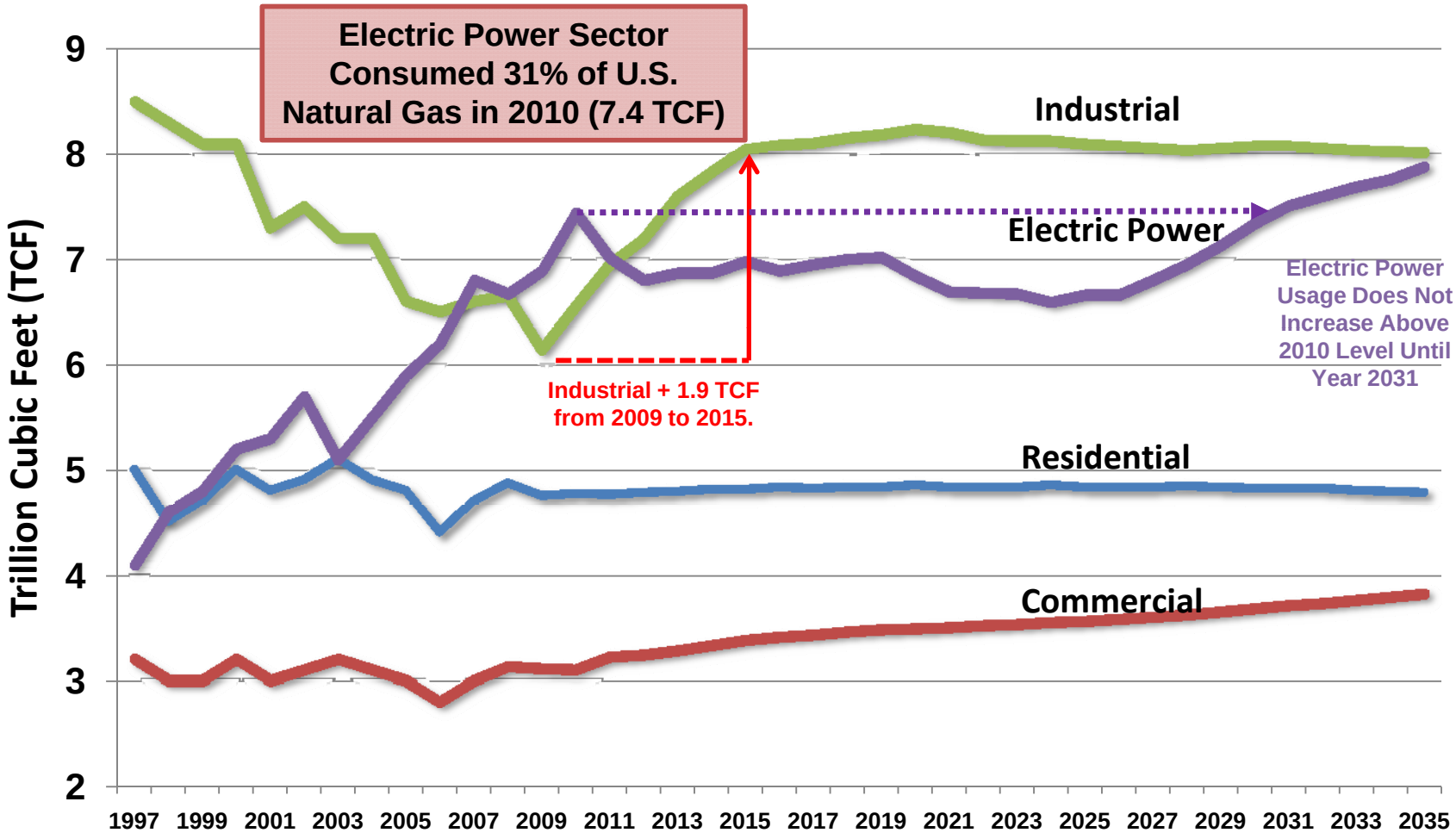
* Primarily traditional biomass, wood, and waste.

Question #3:

Who uses natural gas in the United States?

Domestic Natural Gas Consumption

Sectoral Trends and Projections: 2010 Total Consumption = 23.8 TCF



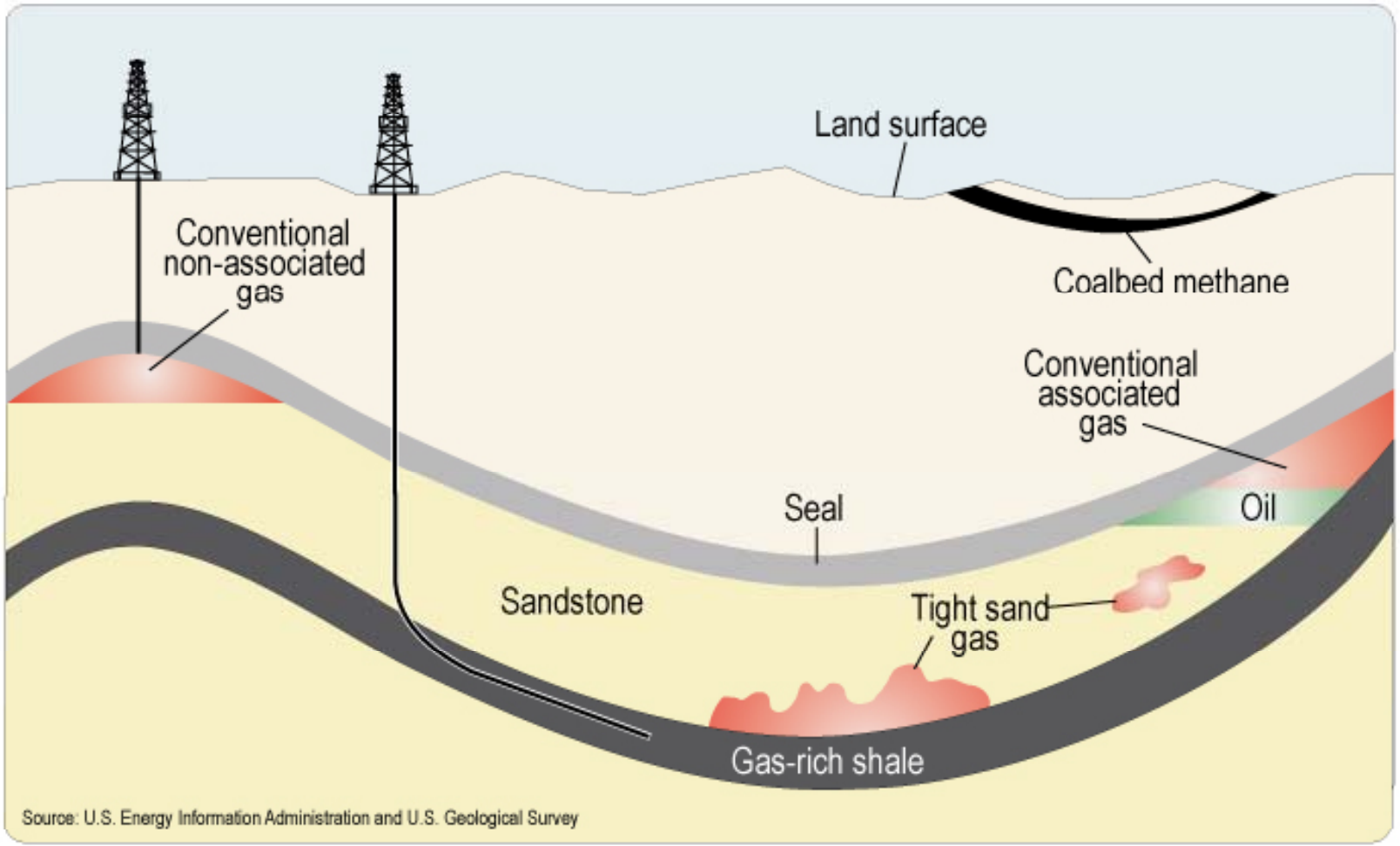
+1.9 TCF Resurgence in Industrial Use of Natural Gas by 2015 Exceeds the Net Incremental Supply; No Increase in Natural Gas Use for Electric Power Sector Until 2031

Source: EIA Annual Energy Review 2009 and Annual Energy Outlook 2011

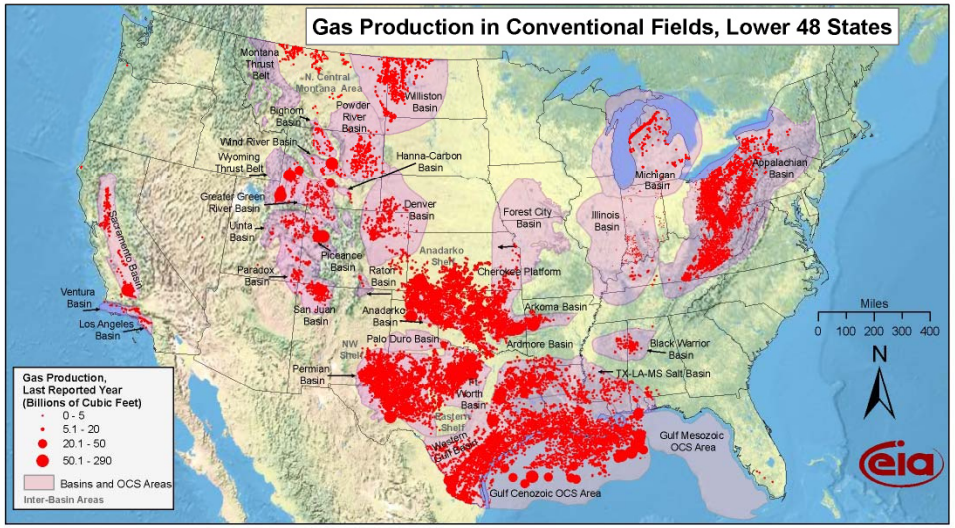
Question #4:

Where does natural gas come from?

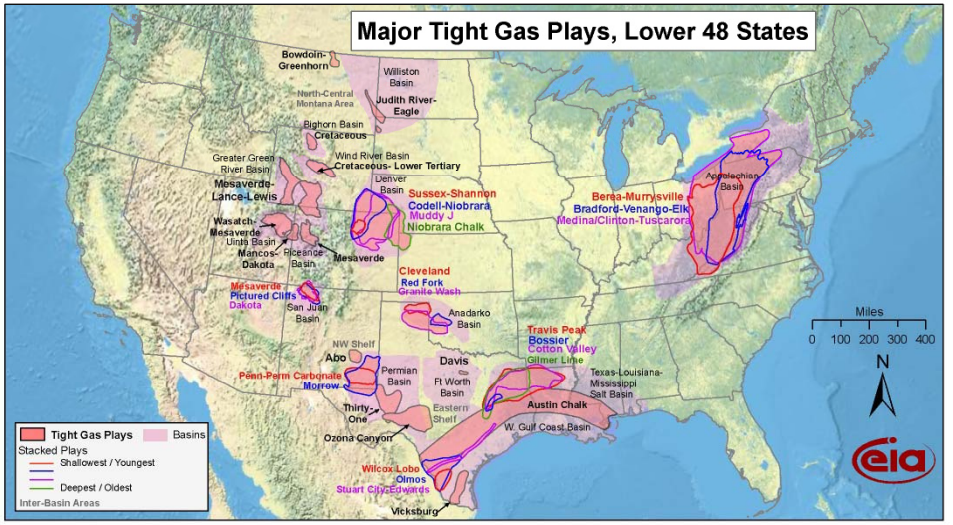
Schematic Geology of Onshore Natural Gas Resources



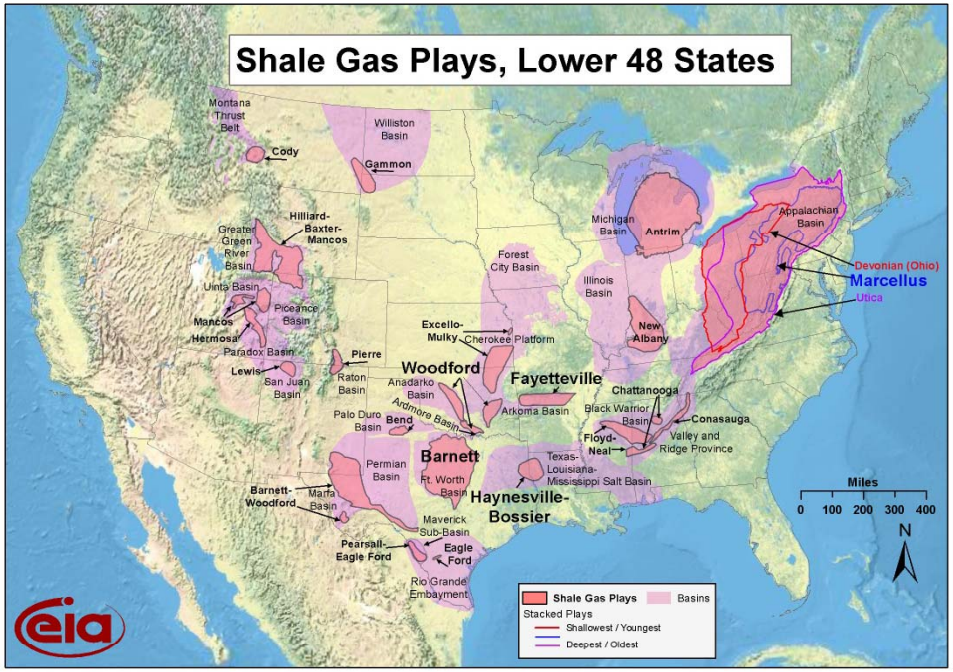
Source: EIA, Today in Energy, February 14, 2011; Modified USGS Figure from Fact Sheet 0113-01; www.eia.doe.gov/todayinenergy/detail.cfm?id=110 Last Accessed May 5, 2011.



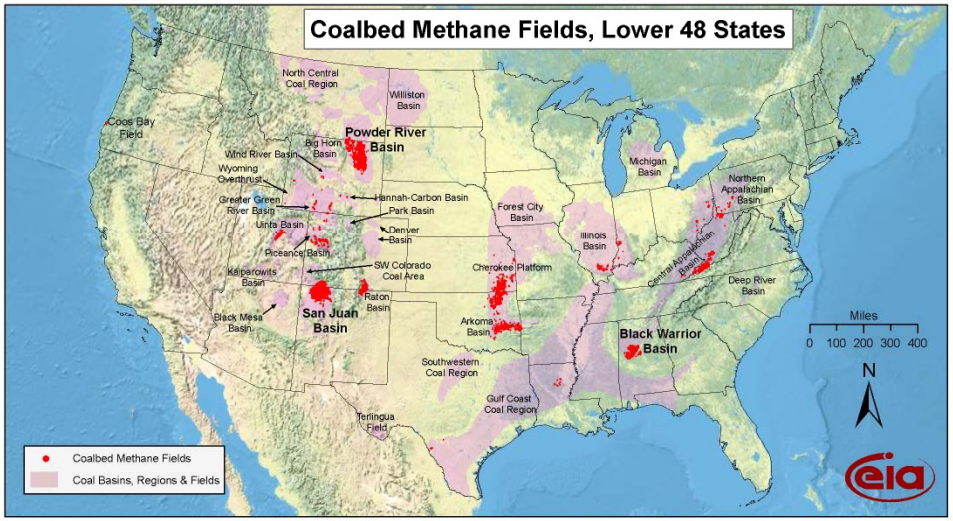
Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009



Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010



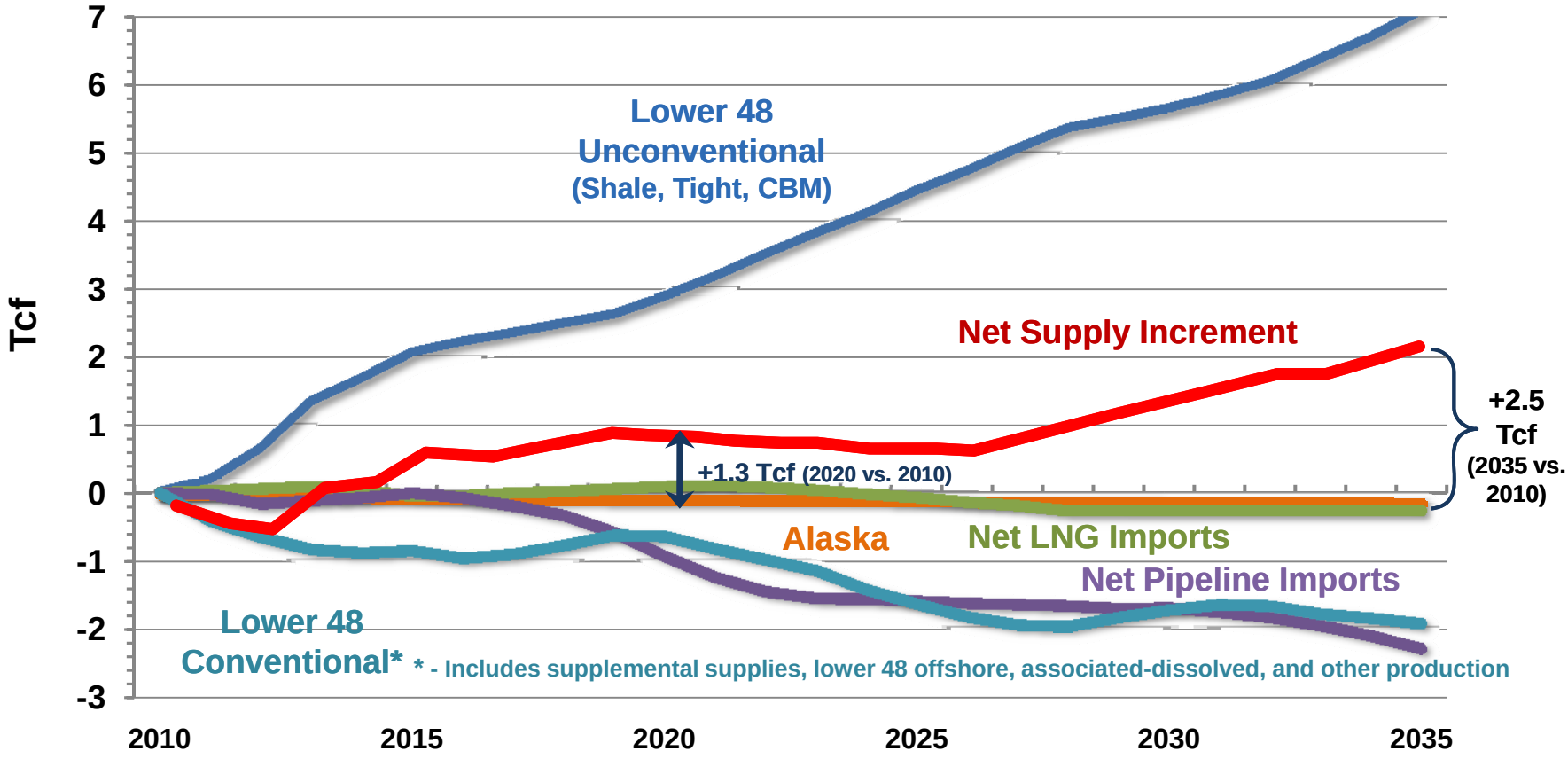
Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

EIA Natural Gas Maps

Source: EIA, Natural Gas Maps, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm Last Accessed May 5, 2011.

Sources of Incremental Natural Gas Supply

(Indexed to 2010)



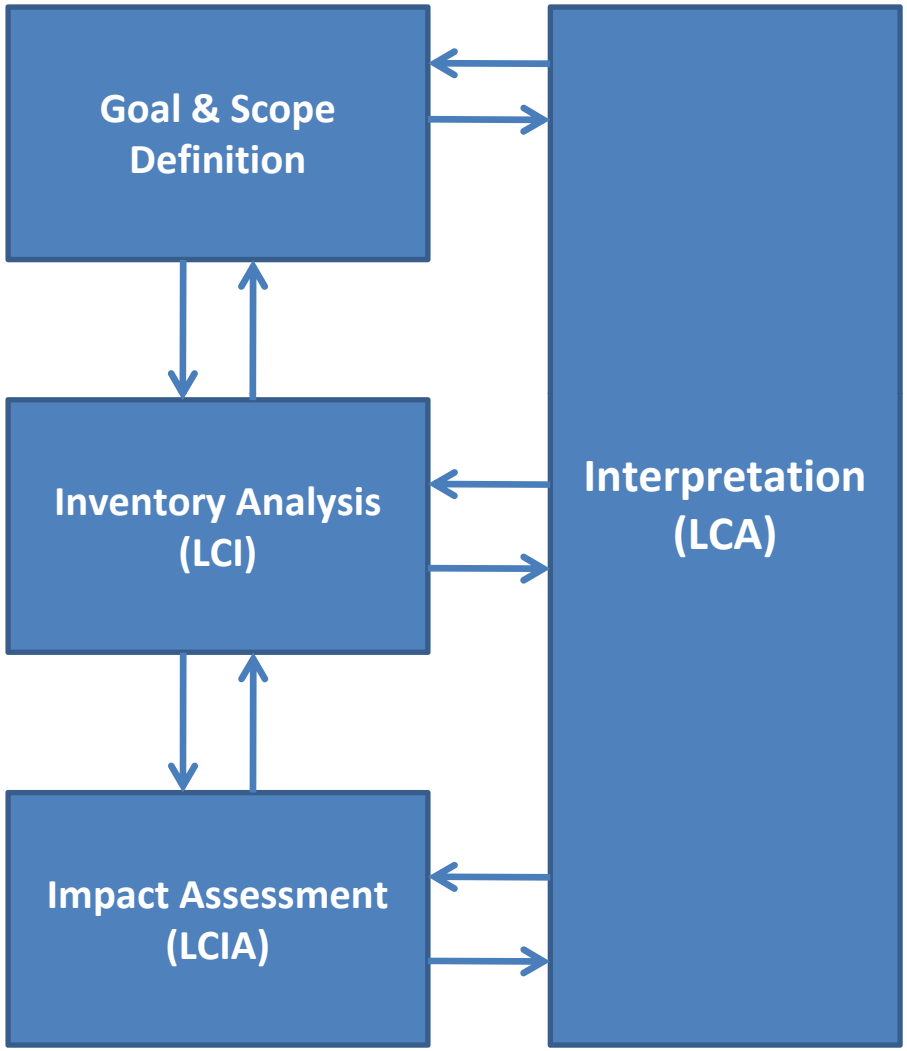
Unconventional Production Growth Offset by Declines in Conventional Production and Net Pipeline Imports; 1.3 Tcf Increment by 2020 Does Not Support Significant Coal Generation Displacement

Source: EIA, Annual Energy Outlook 2011

Question #5:

What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?

Overview: Life Cycle Assessment Approach



The Type of LCA Conducted Depends on Answers to these Questions:

1. What Do You Want to Know?
2. How Will You Use the Results?

International Organization for Standardization (ISO) for LCA

- ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principles and Framework
- ISO 14044 Environmental Management – Life Cycle Assessment – Requirements and Guidelines
- ISO/TR 14047:2003 Environmental Management – Life Cycle Impact Assessment – Examples of Applications of ISO 14042
- ISO/TS 14048:2002 Environmental Management – Life Cycle Assessment – Data Documentation Format

Source: ISO 14040:2006, Figure 1 – Stages of an LCA (reproduced)

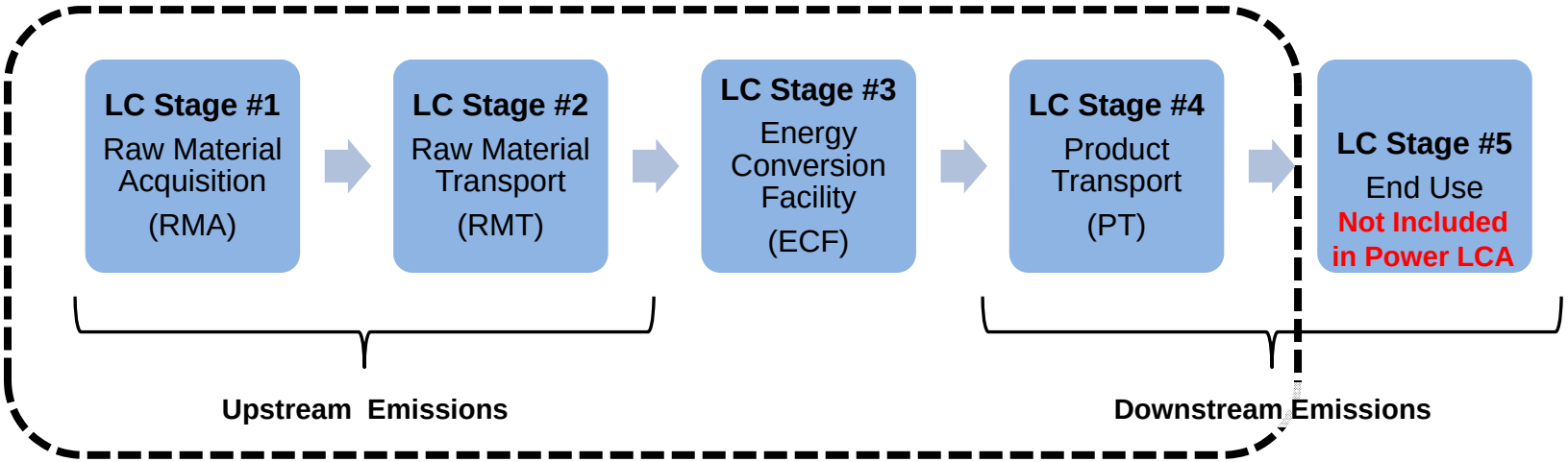
Overview: Life Cycle Assessment Approach

The Type of LCA Conducted Depends on Answers to these Questions :

1. **What Do You Want to Know?**
   - **The GHG footprint of natural gas, lower 48 domestic average, extraction, processing, and delivery to a large end-user (e.g., power plant)**
   - **The comparison of natural gas used in a baseload power generation plant to baseload coal-fired power generation on a lbs CO_2e/MWh basis**
2. **How Will You Use the Results?**
   - **Inform research and development activities to reduce the GHG footprint of both energy feedstock extraction and power production in existing and future operations**

NETL Life Cycle Analysis Approach

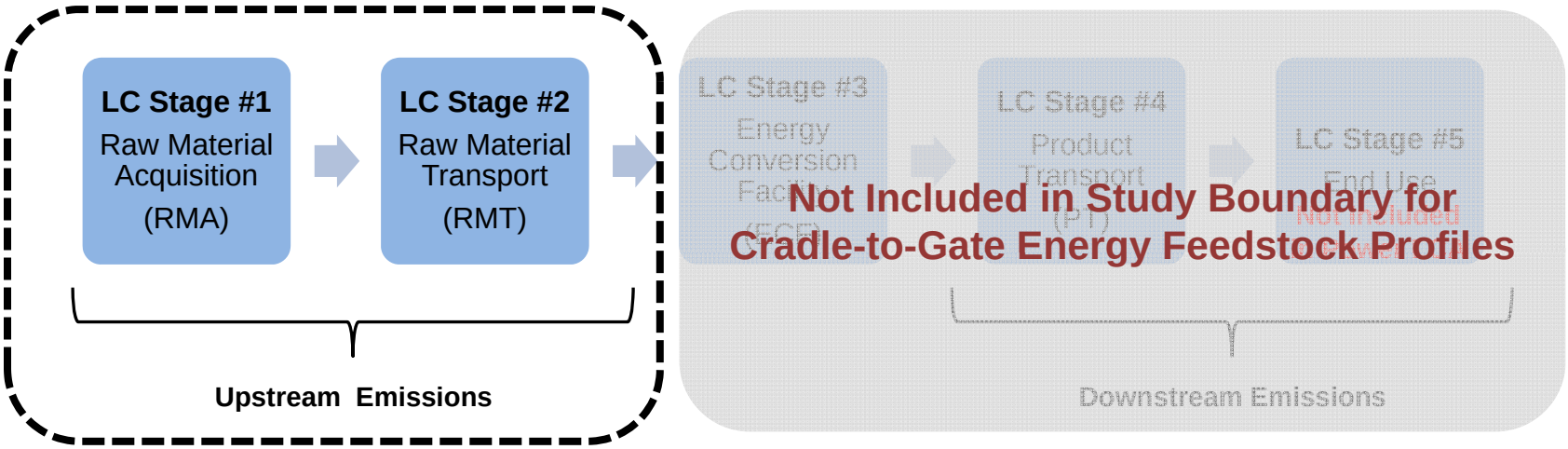
- **Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product or service throughout its life cycle, from raw material acquisition to the final disposal**



- **The ability to compare different technologies depends on the functional unit (denominator); for power LCA studies:**
  - 1 MWh of electricity delivered to the end user

NETL Life Cycle Analysis Approach for Natural Gas Extraction and Delivery Study

- **The study boundary for "domestic natural gas extraction and delivery to large end-users" is represented by Life Cycle (LC) Stages #1 and #2 only.**



- **Functional unit (denominator) for energy feedstock profiles is:**
  - 1 MMBtu of feedstock delivered to end user
    (MMBtu = million British thermal units)

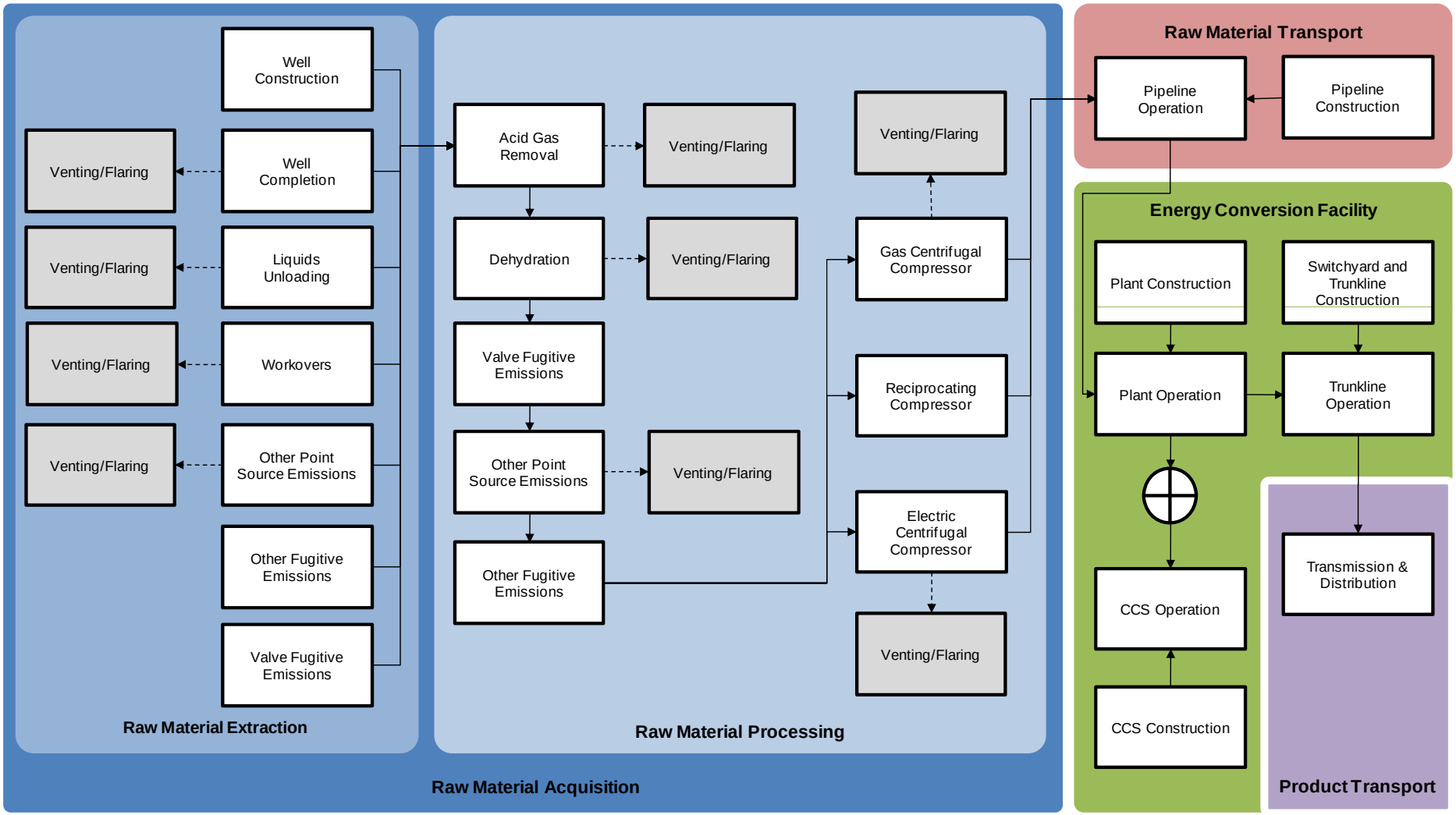
NETL Life Cycle Study Metrics

- **Greenhouse Gases**
  - CO_2, CH_4, N_2O, SF_6
- **Criteria Air Pollutants**
  - NO_X, SO_X, CO, PM10, Pb
- **Air Emissions Species of Interest**
  - Hg, NH_3, radionuclides
- **Solid Waste**
- **Raw Materials**
  - Energy Return on Investment
- **Water Use**
  - Withdrawn water, consumption, water returned to source
  - Water Quality
- **Land Use**
  - Acres transformed, greenhouse gases

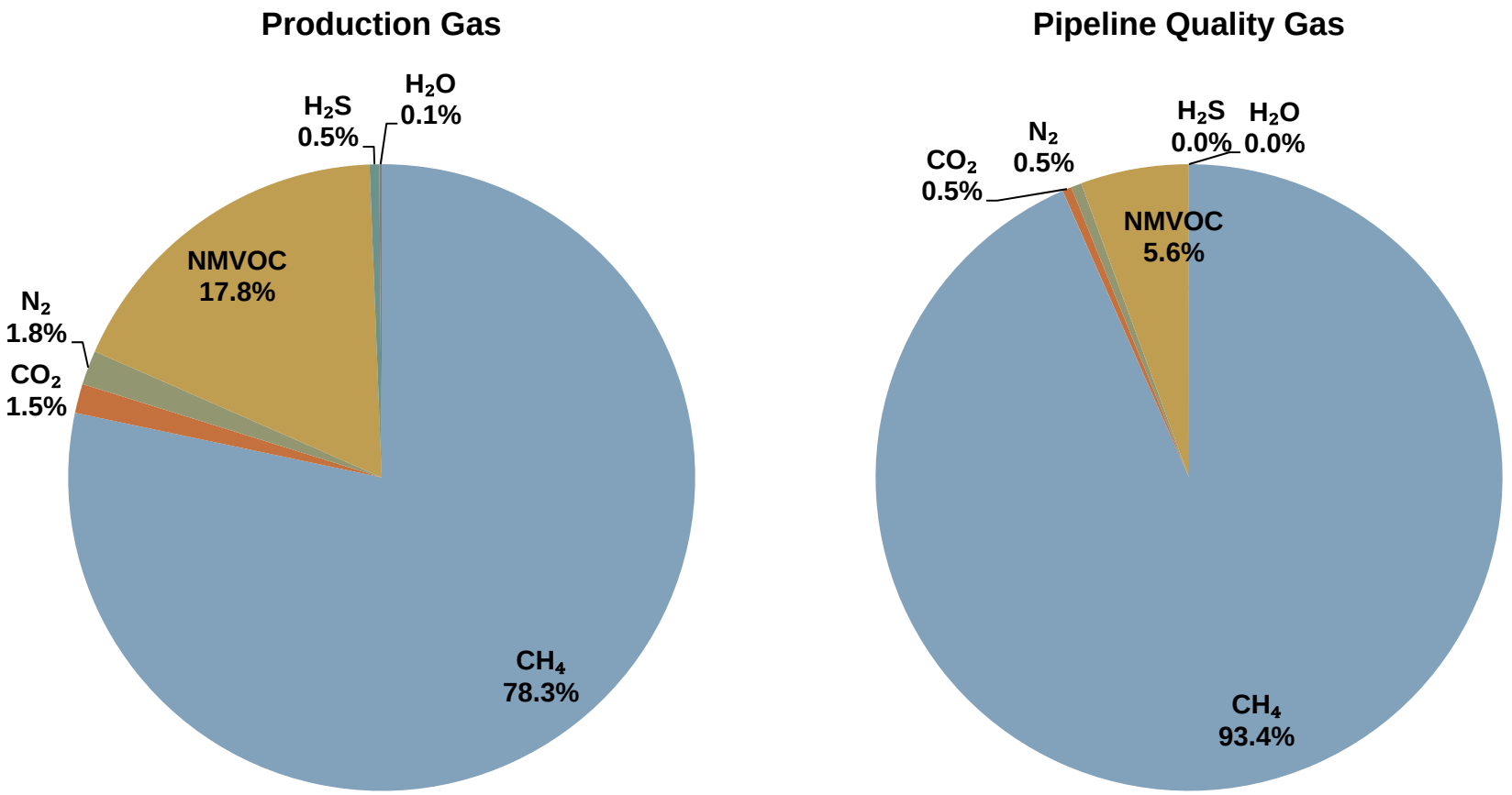
Converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents

CO_2 = 1
CH_4 = 25
N_2O = 298
SF_6 = 22,800

NETL Life Cycle Model for Natural Gas



Natural Gas Composition by Mass



Carbon content (75%) and energy content (1,027 btu/cf) of pipeline quality gas is very similar to raw production gas (within 99% of both values)

Natural Gas Extraction Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
Estimated Ultimate Recovery (EUR), Production Gas	BCF/well	8.6	4.4	67.7	1.2	3.0	0.2
Production Rate (30-yr average)	MCF/day	782	399	6,179	110	274	20
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	MCF/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	MCF/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	MCF/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.043	0.043	0.010	0.043	0.043	0.043

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Acid Gas Removal (AGR) and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%					
Methane Absorbed into Amine Solution	lb CH_4/MCF	0.04					
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/MCF	0.56					
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/MCF	0.21					
NMVOC Absorbed into Amine Solution	lb NMVOC/MCF	6.59					
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%					
Water Removed by Dehydrator Unit	lb H_2O/MCF	0.045					
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/MCF	0.0003					
Pneumatic Devices & Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%					
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05					
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.02					
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.03					

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Natural Gas Transmission Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Emissions on Transmission Infrastructure							
Pipeline Transport Distance (national average)	Miles	450					
Transmission Pipeline Infrastructure, Fugitive	lb CH_4/MCF-Mile	0.0003					
Transmission Pipeline Infrastructure, Fugitive (per 450 miles)	lb CH_4/MCF	0.15					
Natural Gas Compression on Transmission Infrastructure							
Distance Between Compressor Stations	Miles	75					
Compression, Gas-powered Reciprocating	Percent	29%					
Compression, Gas-powered Centrifugal	Percent	64%					
Compression, Electrical Centrifugal	Percent	7%					

Uncertainty Analysis Modeling Parameters

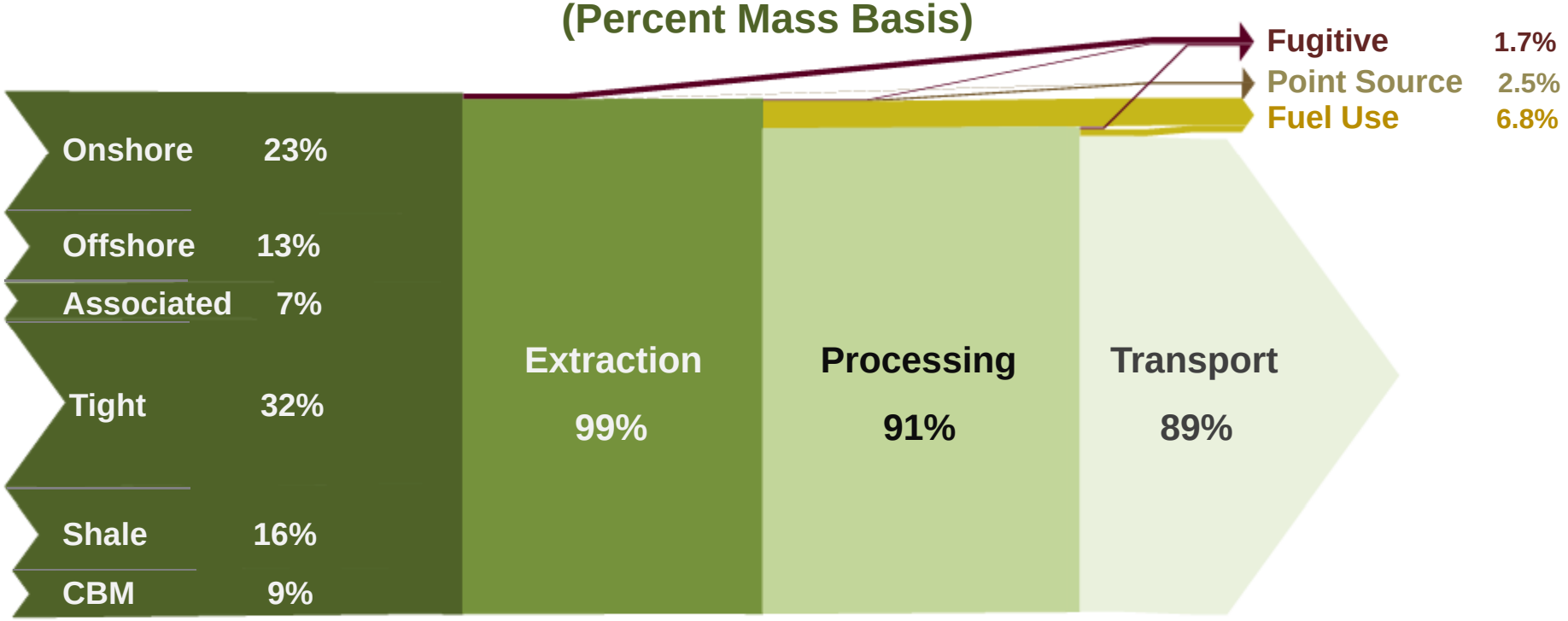
Parameter	Units	Scenario	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Production Rate	MCF/day	Low	403 (-49%)	254 (-36%)	3,140 (-49%)	77 (-30%)	192 (-30%)	14 (-30%)
		Nominal	**782**	**399**	**6,179**	**110**	**274**	**20**
		High	1,545 (+97%)	783 (+96%)	12,284 (+99%)	142 (+30%)	356 (+30%)	26 (+30%)
Flaring Rate at Well	%	Low	41% (-20%)	41% (-20%)	41% (-20%)	12% (-20%)	12% (-20%)	41% (-20%)
		Nominal	**51%**	**51%**	**51%**	**15%**	**15%**	**51%**
		High	61% (+20%)	61% (+20%)	61% (+20%)	18% (+20%)	18% (+20%)	61% (+20%)
Pipeline Distance	miles	Low	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)
		Nominal	**450**	**450**	**450**	**450**	**450**	**450**
		High	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)

Error bars reported are based on setting each of the three parameters above to the values that generate the lowest and highest result.

Note: "Production Rate" and "Flaring Rate at Well" have an inverse relationship on the effect of the study result. For example to generate the lower bound on the uncertainty range both "Production Rate" and "Flaring Rate Well" were set to "High" and "Pipeline Distance" was set to "Low".

Accounting for Natural Gas from Extraction thru Delivery to a Large End-User

(Percent Mass Basis)

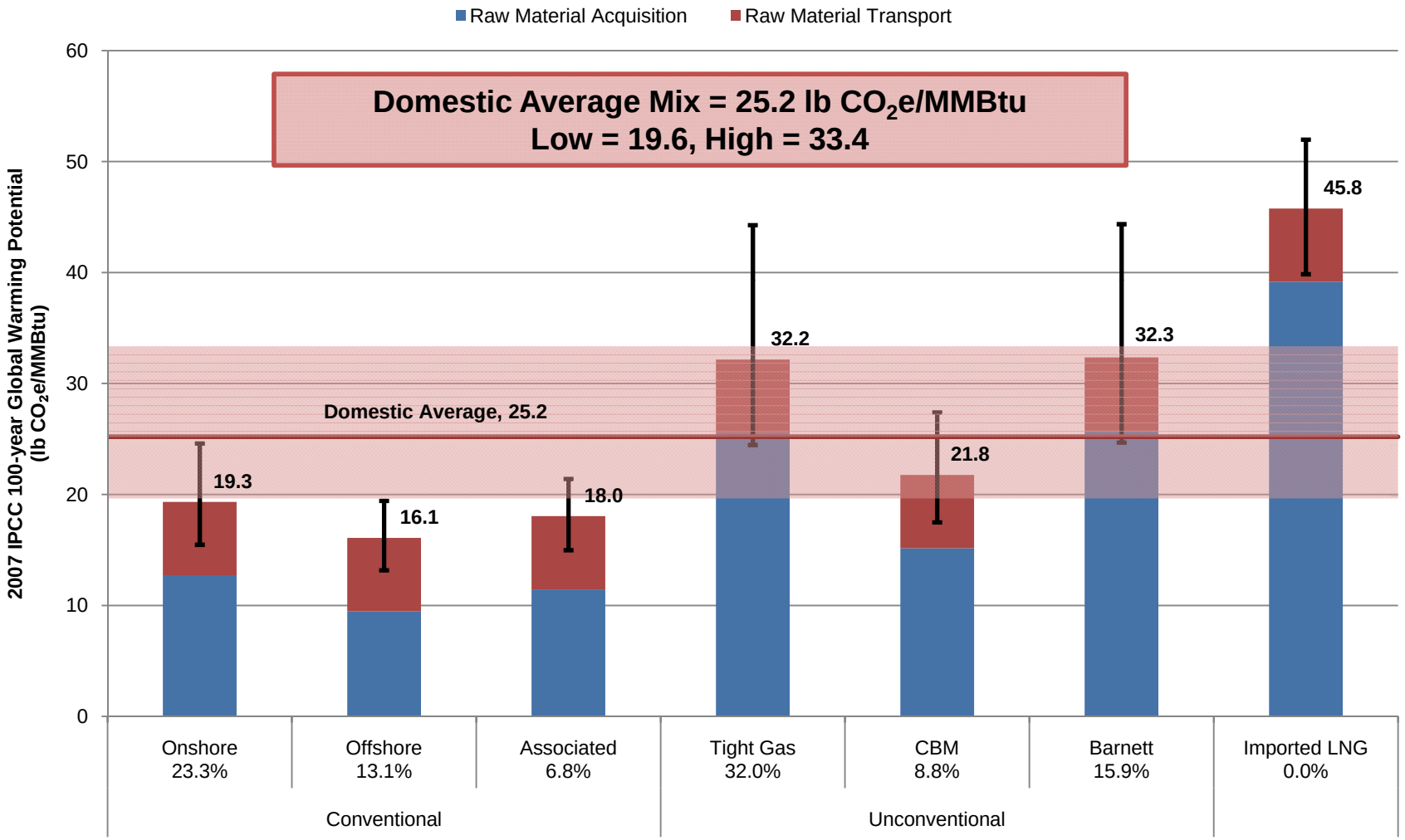


Natural Gas Resource Table	Raw Material Acquisition		Raw Material Transport	Cradle-to-Gate Total:
	Extraction	Processing		
Extracted from Ground	100%	N/A	N/A	100%
Fugitive Losses	1.1%	0.2%	0.4%	1.7%
Point Source Losses (Vented or Flared)	0.1%	2.4%	0.0%	2.5%
Fuel Use	0.0%	5.3%	1.6%	6.8%
Delivered to End User	N/A	N/A	89.0%	89.0%

11% of Natural Gas Extracted from the Earth is Consumed for Fuel Use, Flared, or Emitted to the Atmosphere (point source or fugitive)

Of this, 62% is Used to Power Equipment

Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

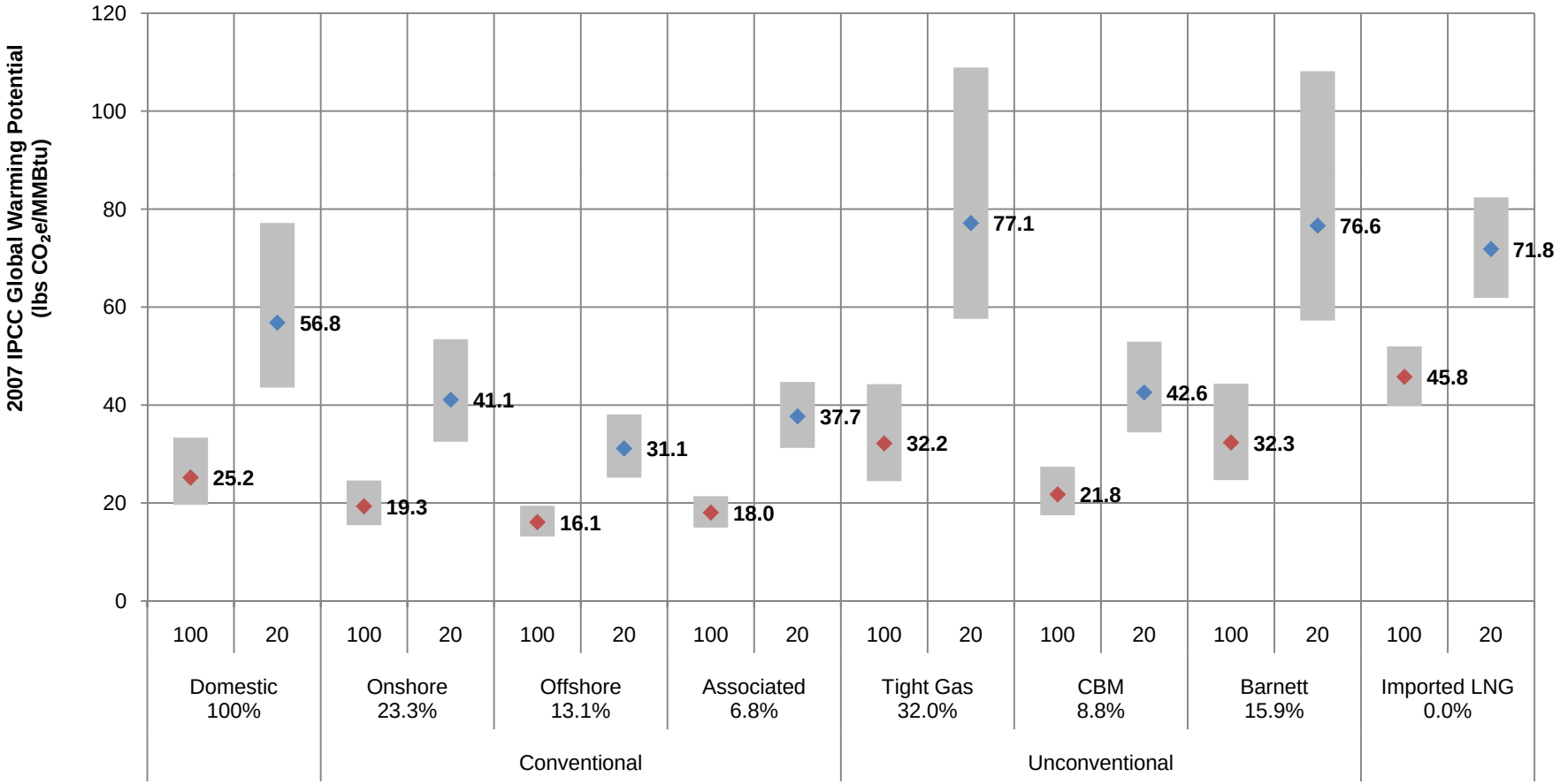


Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

Comparison of 2007 IPCC GWP Time Horizons:

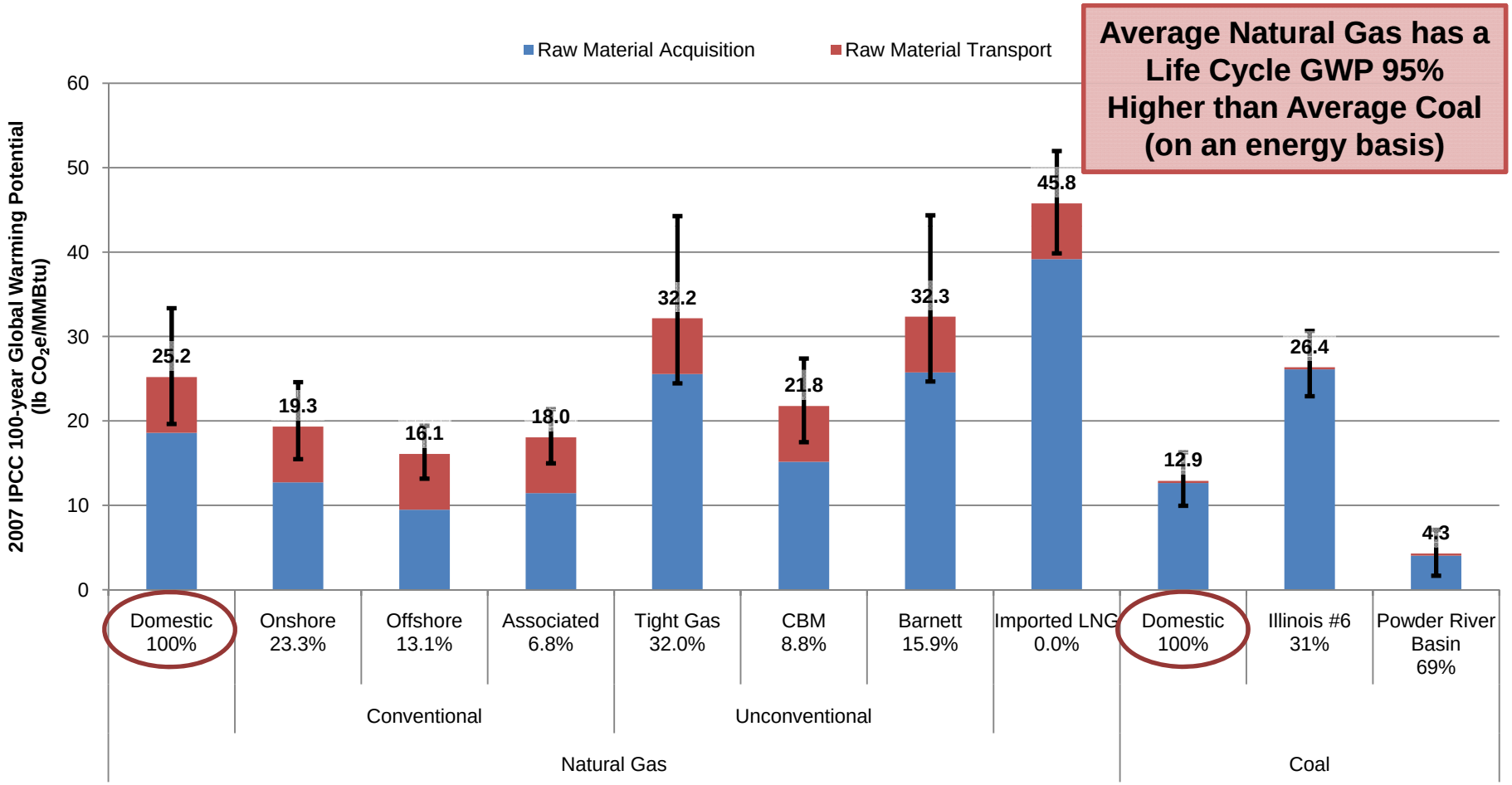
100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289



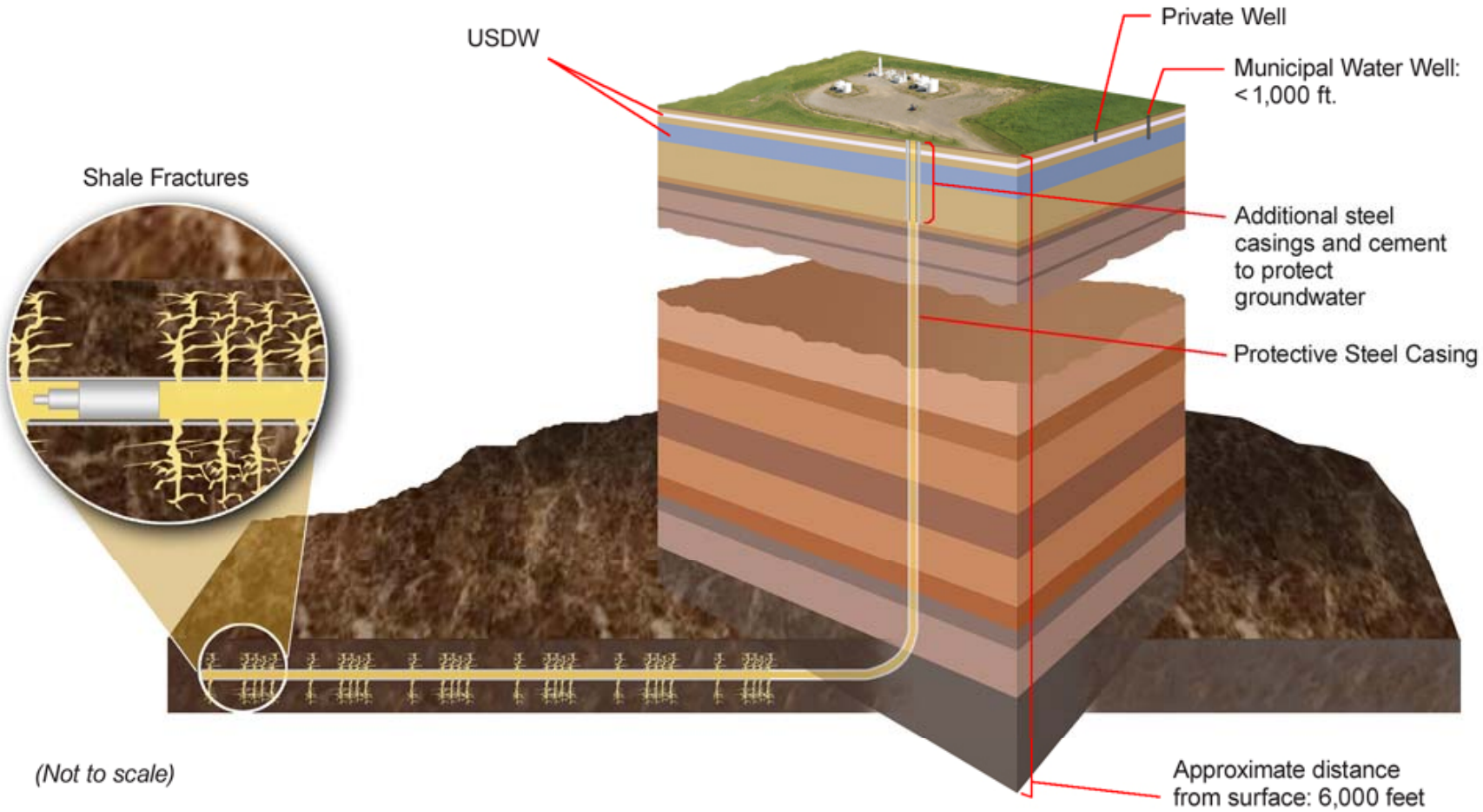
Life Cycle GHG Results for "Average" Natural Gas Extraction and Delivery to a Large End-User

Comparison of Natural Gas and Coal Energy Feedstock GHG Profiles



Average Natural Gas has a Life Cycle GWP 95% Higher than Average Coal (on an energy basis)

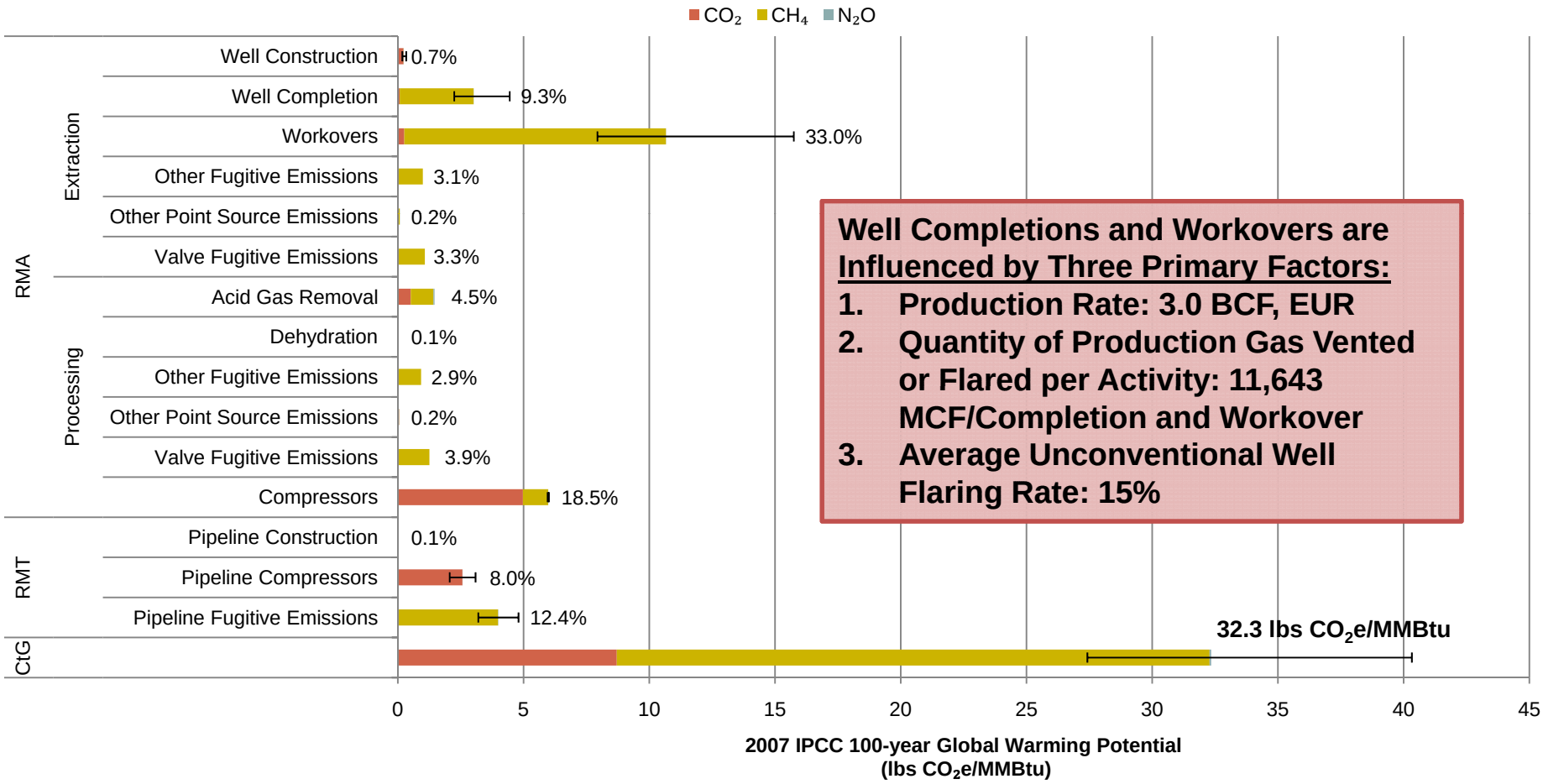
A Deeper Look at Unconventional Natural Gas Extraction via Horizontal Well, Hydraulic Fracturing (*the Barnett Shale Model*)



Source: NETL, *Shale Gas: Applying Technology to Solve America's Energy Challenge*, January 2011

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

GWP Result: IPCC 2007, 100-yr (lb CO_2e/MMBtu)

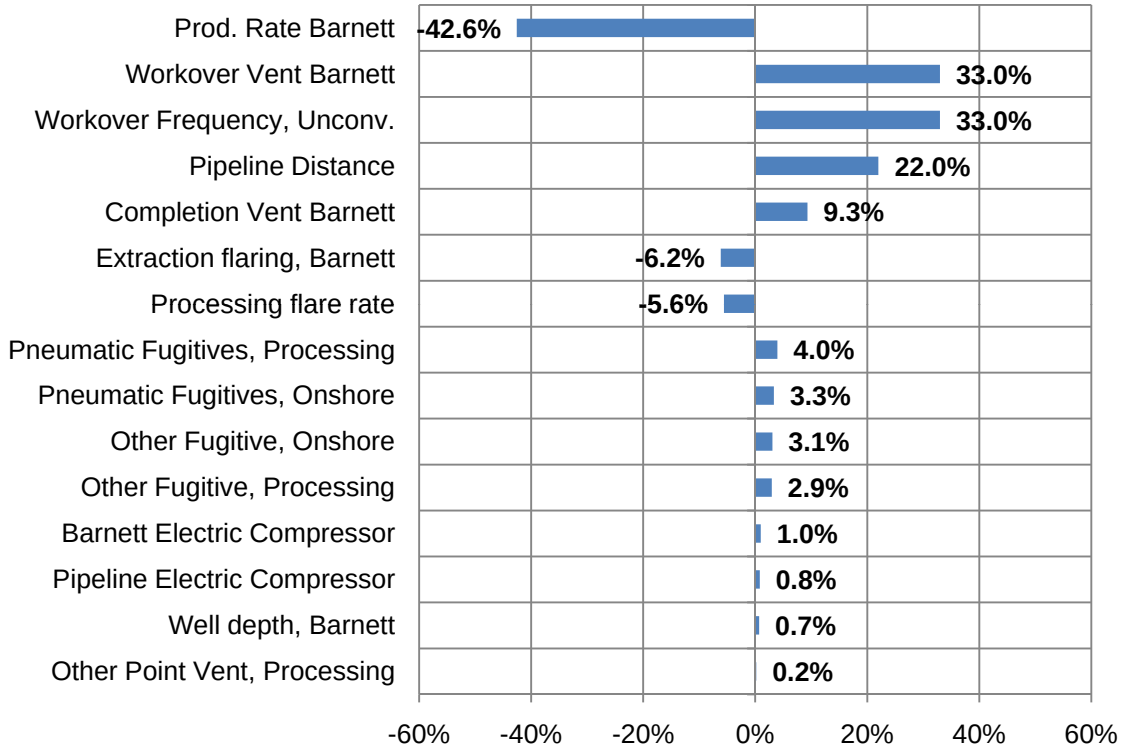


Well Completions and Workovers are Influenced by Three Primary Factors:

1. **Production Rate: 3.0 BCF, EUR**
2. **Quantity of Production Gas Vented or Flared per Activity: 11,643 MCF/Completion and Workover**
3. **Average Unconventional Well Flaring Rate: 15%**

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

Sensitivity Analysis



Default Value	Units
11,508	lb/day
489,023	lb/episode
0.118	episodes/yr
450	miles
489,023	lb/episode
15.0	%
100	%
0.001480	lb fugitives/lb processed gas
0.001210	lb fugitives/lb extracted gas
0.001119	lb fugitives/lb extracted gas
0.001089	lb fugitives/lb processed gas
25	%
7	%
13,000	feet
0.0003940	lb fugitives/lb processed gas

"0%" = 32.3 lb CO_2e/MMBtu Delivered; IPCC 2007, 100-yr Time Horizon

Example: A 1% increase in production rate from 11,508 lb/day to 11,623 lb/day results in a 0.426% decrease in cradle-to-gate GWP, from 32.3 to 32.2 lbs CO_2e/MMBtu

Question #6:

How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?

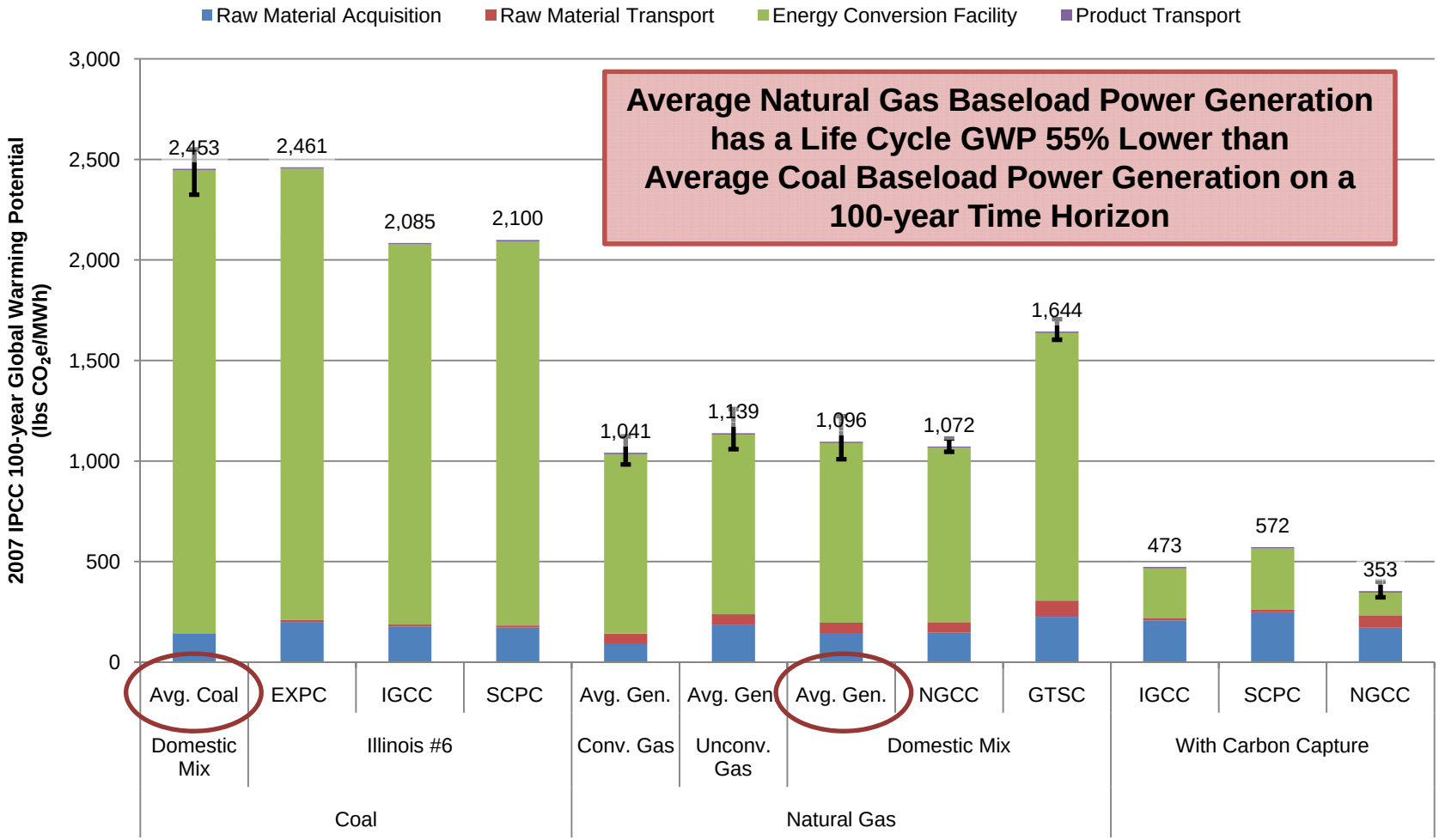
Power Technology Modeling Properties

Plant Type	Plant Type Abbreviation	Fuel Type	Capacity (MW)	Capacity Factor	Net Plant HHV Efficiency
2009 Average Coal Fired Power Plant[a]	Avg. Coal	Domestic Average	Not Calculated	Not Calculated	33.0%
Existing Pulverized Coal Plant	EXPC	Illinois No. 6	434	85%	35.0%
Integrated Gasification Combined Cycle Plant	IGCC	Illinois No. 6	622	80%	39.0%
Super Critical Pulverized Coal Plant	SCPC	Illinois No. 6	550	85%	36.8%
2009 Average Baseload (> 40 MW) Natural Gas Plant[a]	Avg. Gen.	Domestic Average	Not Calculated	Not Calculated	47.1%
Natural Gas Combined Cycle Plant	NGCC	Domestic Average	555	85%	50.2%
Gas Turbine Simple Cycle	GTSC	Domestic Average	360	85%	32.6%
Integrated Gasification Combined Cycle Plant with 90% Carbon Capture	IGCC/CCS	Illinois No. 6	543	80%	32.6%
Super Critical Pulverized Coal Plant with 90% Carbon Capture	SCPC/CCS	Illinois No. 6	550	85%	26.2%
Natural Gas Combined Cycle Plant with 90% Carbon Capture	NGCC/CCS	Domestic Average	474	85%	42.8%

[a] **Net plant higher heating value (HHV) efficiency reported is based on the weighted mean of the 2007 fleet as reported by U.S. EPA, eGrid (2010).**

Comparison of Power Generation Technology Life Cycle GHG Footprints

Raw Material Acquisition thru Delivery to End Customer (lb CO_2e/MWh)



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

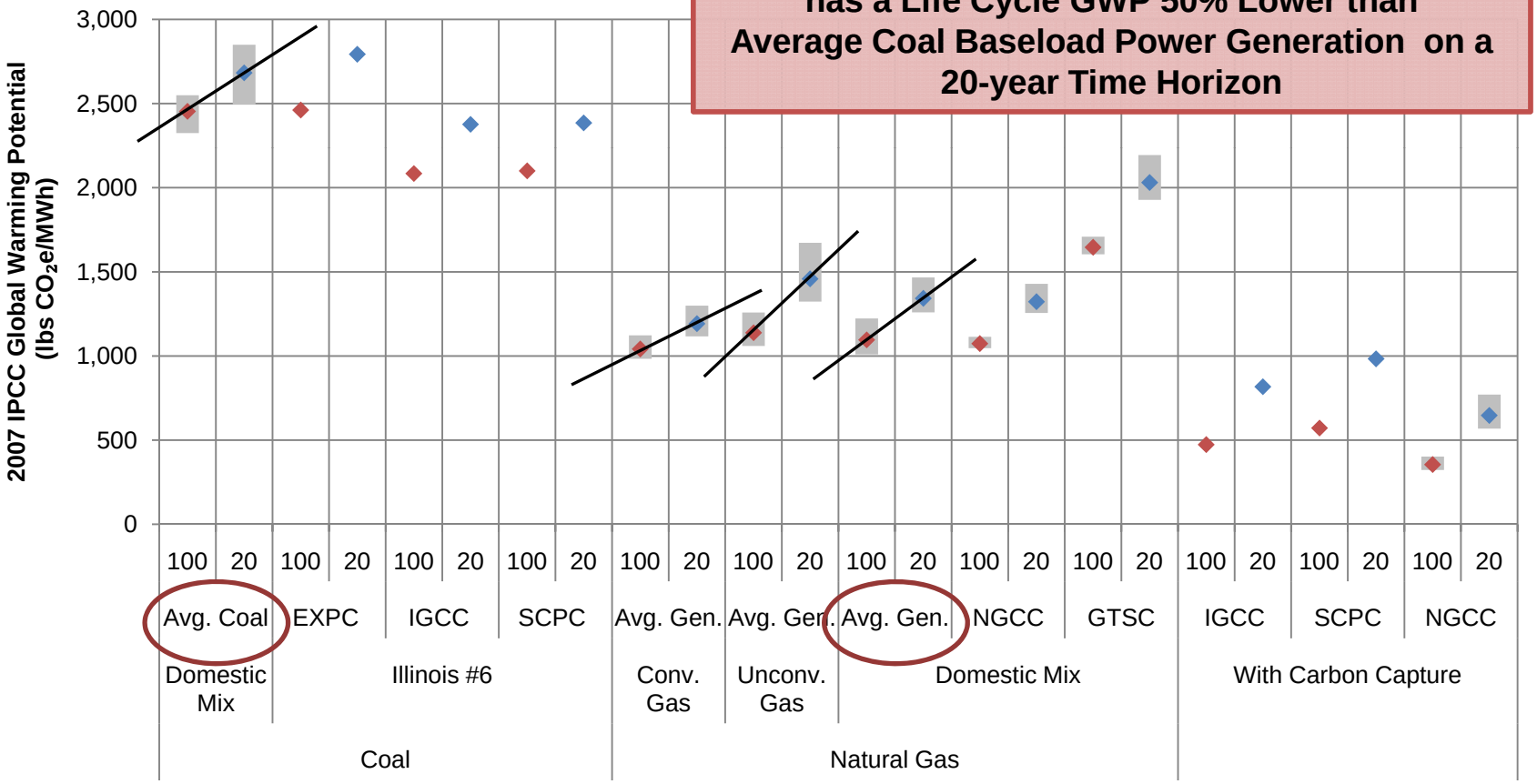
Comparison of Power Generation Technology Life Cycle GHG Footprints (lbs CO_2e/MWh)

Comparison of 2007 IPCC GWP Time Horizons:

100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289

Average Natural Gas Baseload Power Generation has a Life Cycle GWP 50% Lower than Average Coal Baseload Power Generation on a 20-year Time Horizon



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Study Data Limitations

- **Data Uncertainty**
  - Episodic emission factors
  - Formation-specific production rates
  - Flaring rates (extraction and processing)
  - Natural gas pipeline transport distance

- **Data Availability**
  - Formation-specific gas compositions (including CH_4, H_2S, NMVOC, and water)
  - Effectiveness of green completions and workovers
  - Fugitive emissions from around wellheads (between the well casing and the ground)
  - GHG emissions from the production of fracing fluid
  - Direct and indirect GHG emissions from land use from access roads and well pads
  - Gas exploration
  - Treatment of fracing fluid
  - Split between venting and fugitive emissions from pipeline transport

Question #7:

What are the opportunities for reducing GHG emissions?

Technology Opportunities

- **Opportunities for Reducing the GHG Footprint of Natural Gas Extraction and Delivery**
  - Reduce emissions from unconventional gas well completions and workovers
    - Better data is needed to properly characterize this opportunity based on basin type, drilling method, and production rate
  - Improve compressor fuel efficiency
  - Reduce pipeline fugitive emissions thru technology and best management practices (collaborative initiatives)

- **Opportunities for Reducing the GHG Footprint of Natural Gas and Coal-fired Power Generation**
  - Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir (CO_2-EOR)
  - Improve existing power plant efficiency
  - Invest in advanced power research, development, and demonstration

All Opportunities Need to Be Evaluated on a Sustainable Energy Basis: Environmental Performance, Economic Performance, and Social Performance (e.g., energy reliability and security)

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Recent NETL Life Cycle Assessment Reports

Available at http://www.netl.doe.gov/energy-analyses/:

- Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant
- Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant
- Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant
- Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant
- Life Cycle Analysis: Power Studies Compilation Report

Analysis complete, report in draft form:

- Life Cycle GHG Analysis of Natural Gas Extraction and Delivery
- Life Cycle Assessment of Wind Power with GTSC Backup
- Life Cycle Assessment of Nuclear Power

Other related Life Cycle Analysis publications available on NETL web-site:

- Life Cycle Analysis: Power Studies Compilation Report (Pres., LCA X Conference)
- An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin (Report)
- A Comparative Assessment of CO_2 Sequestration through Enhanced Oil Recovery and Saline Aquifer Sequestration (Presentation, LCA X Conference)

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

October 24, 2011

DOE/NETL-2011/1522

U.S. DEPARTMENT OF ENERGY

Disclaimer

Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

DOE/NETL-2011/1522

Final Report

October 24, 2011

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Acronyms and Abbreviations

AGR	Acid gas removal
API	American Petroleum Institute
bbl	Barrel
Bcf	Billion cubic feet
BOE	Barrel of oil equivalent
Btu	British thermal unit
CBM	Coal bed methane
CCS	Carbon capture and sequestration
cf	Cubic feet
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUR	Estimated ultimate recovery
EXPC	Existing pulverized coal
g	Gram
gal	Gallon
Gg	Gigagram
GHG	Greenhouse gas
GTSC	Gas turbine simple cycle
GWP	Global warming potential
H_2S	Hydrogen sulfide
hp-hr	Horsepower-hour
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
lb, lbs	Pound, pounds
LCA	Life cycle assessment, analysis
LNG	Liquefied natural gas
m	Meter
m^3	Meters cubed
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MJ	Megajoule
MMbbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NMVOC	Non-methane volatile organic compound
NREL	National Renewable Energy Laboratory
PRB	Powder River Basin
psig	Pounds per square inch gauge
PT	Product transport
RMA	Raw material acquisition
RMT	Raw material transport
SCPC	Super critical pulverized coal
T&D	Transmission and distribution
Tcf	Trillion cubic feet
ton	Short ton (2,000 lb)
tonne	Metric ton (1,000 kg)
UP	Unit process

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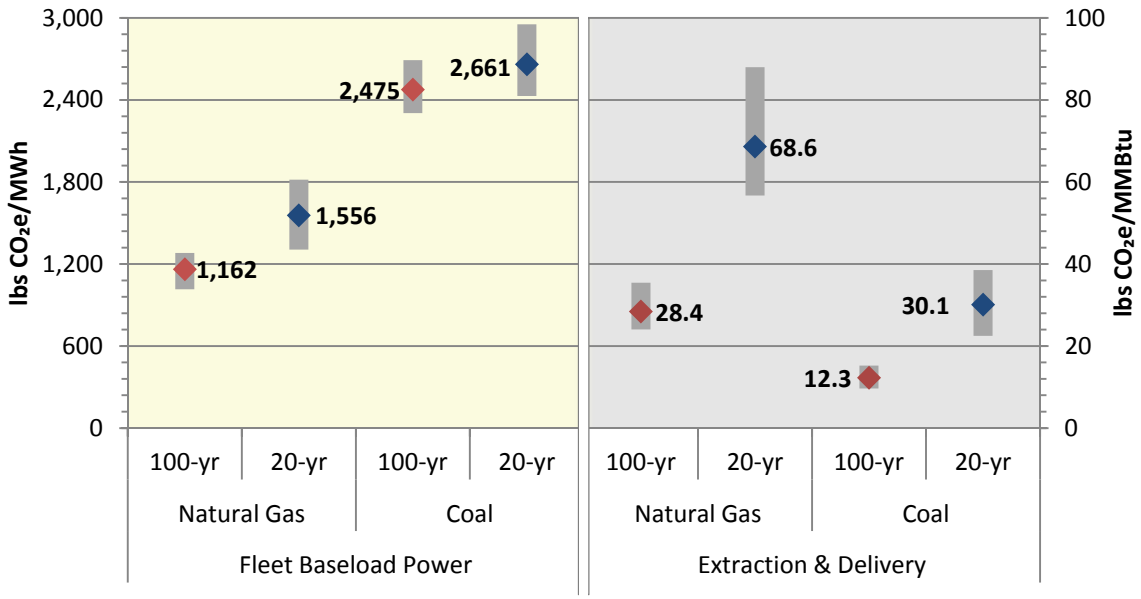
Executive Summary

Natural gas-fired baseload power production has life cycle greenhouse gas emissions 42 to 53 percent lower than those for coal-fired baseload electricity, after accounting for a wide range of variability and compared across different assumptions of climate impact timing. The lower emissions for natural gas are primarily due to differences in the current fleets' average efficiency – 53 percent for natural gas versus 35 percent for coal, and a higher carbon content per unit of energy for coal than natural gas. Even using unconventional natural gas, from tight sands, shale and coal beds, and compared with a 20-year global warming potential (GWP), natural gas-fired electricity has 39 percent lower greenhouse gas emissions than coal per delivered megawatt-hour (MWh) using current technology.

In a life cycle analysis (LCA), comparisons must be based on providing an equivalent service or function, which in this study is the delivery of 1 MWh of electricity to an end user. This life cycle greenhouse gas inventory also developed upstream (from extraction to delivery to a power plant) emissions for delivered energy feedstocks, including six different domestic sources of natural gas, of which three are unconventional gas, and two types of coal, and then combines them both into domestic mixes. These are important characterizations for the LCA community, and can be used as inputs into a variety of processes. However, these upstream, or cradle-to-gate, results are not appropriate to compare when making energy policy decisions, since the two uncombusted fuels do not provide an equivalent function. These results highlight the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Figure ES-1: Natural Gas and Coal GHG Emissions Comparison

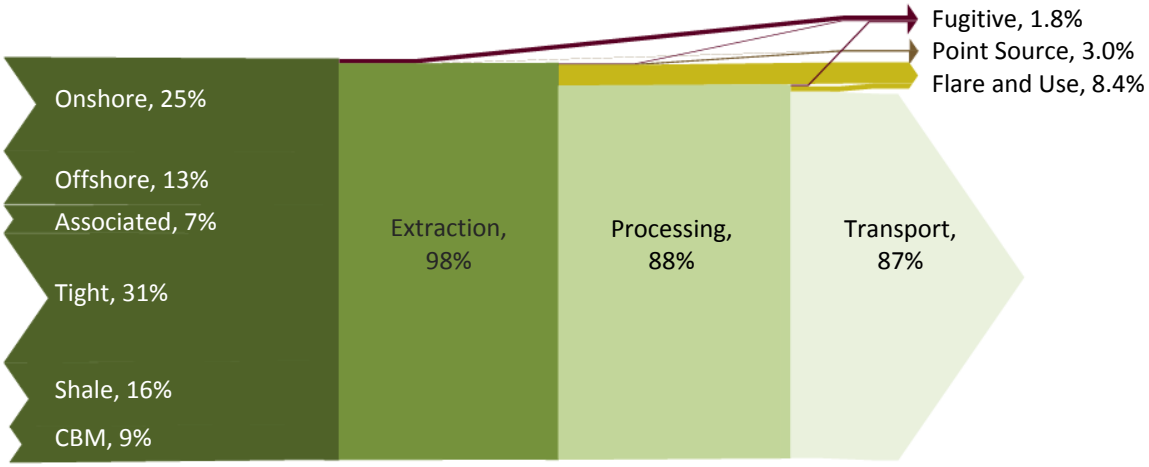


Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases (EPA, 2011b). As **Figure ES-2** shows, there are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted

natural gas —64 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy. Note that this figure accounts for the total mass of natural gas extracted from the earth, including water, acid gases, and other non-methane content.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 24 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

Figure ES-2: Cradle-to-Gate Reduction in Delivered Natural Gas for 2009



The conclusions drawn from this analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few key parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

Table ES-1: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

This analysis inventoried both average and marginal production rates for each natural gas type, with results shown in **Table ES-1**. The average represents natural gas produced from all wells, including older and low productivity stripper wells. The marginal production rate represents natural gas from

newer, higher productivity wells. The largest difference was for onshore conventional natural gas, which had a 41 percent reduction in upstream greenhouse gas emissions from 20.1 to 34.2 lbs CO_2e/MMBtu when going from marginal to average production rates. This change has little impact on emissions from power production.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all options need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security. There are many opportunities for decreasing the greenhouse gas emissions from natural gas and coal extraction, delivery and power production, including reducing fugitive methane emissions at wells and mines, and implementing advanced combustion technologies and carbon capture and storage.

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1 Introduction

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, commercial, industrial, and transportation applications in addition to an expanding role in power production. However, the primary component of natural gas by mass is methane, which is also a powerful greenhouse gas—8 to 72 times as potent as carbon dioxide (Forster et al., 2007). Losses of this methane to the atmosphere during the extraction, transmission, and delivery of natural gas to end users made up 32 percent of U.S. 2009 total methane emissions, and 3 percent of all greenhouse gases (EPA, 2011b). The rate of loss, and the associated emissions, varies with the source of natural gas—both the geographic location of the formation, as well as the technology used to extract the gas.

This report expands upon previous life cycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. Emissions inventories are created for the 2009 average natural gas production, but also for natural gas produced from the next highly-productive well for each source of natural gas. This context allows analysis of what the emissions are, and also what they could be in the future.

This analysis also includes an expanded system which compares the life cycle greenhouse gases (GHGs) from baseload natural gas-fired power plants with the GHGs generated by coal-fired plants, including extraction and transportation of the respective fuels. This comparison provides perspective on the scale of fuel extraction and delivery emissions relative to subsequent emissions from power generation and electricity transmission.

Beyond presenting the inventory, the goal of this report is to provide a clear presentation of NETL's natural gas model, including documentation of key assumptions, data sources, and model sensitivities. Further, areas of large uncertainty in the inventory are highlighted, along with areas for potential improvement for both data collection and greenhouse gas reductions.

This greenhouse gas inventory and analysis are part of a larger comprehensive life cycle assessment being performed on the same natural gas system. That assessment effort includes new sources of shale gas and expands the inventory beyond greenhouse gases to include criteria and hazardous air pollutants, water use and quality, direct and indirect land use and greenhouse gases from land use change.

2 Inventory Method, Assumptions, and Data

This ISO 14040-compliant inventory and analysis applies the LCA framework to determine the greenhouse gas burdens of natural gas extraction, transport and use in the U.S. The boundaries, basis of comparison, model structure, and data used by this analysis are discussed below. Further detail is available in the Appendix to this document.

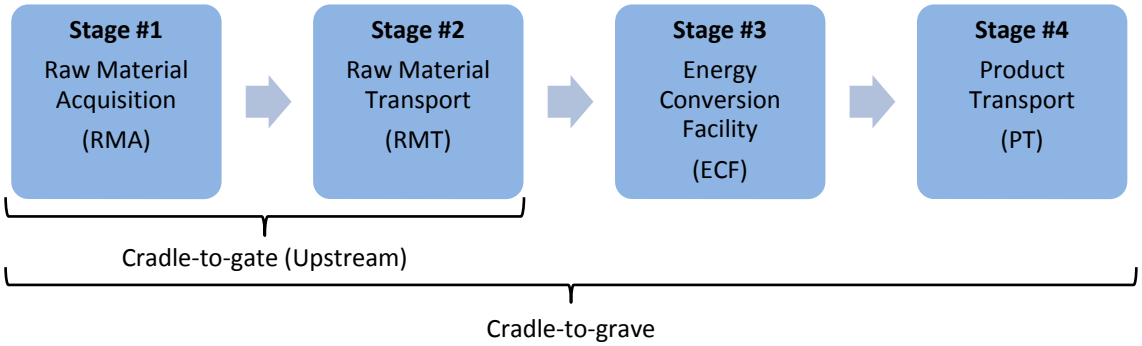
2.1 Boundaries

The first piece of this analysis is a cradle-to-gate greenhouse gas inventory that focuses on raw material acquisition and transport; as such, it is also referred to as an upstream inventory, upstream being a relative term (relative, in this case, to the power plant). As shown in **Figure 2-1**, and in more detail in **Figure 2-2**, the boundary of Stage #1 includes all construction and operation activities necessary to extract fuel from the earth, and ends when fuel is extracted, prepared, and ready for final transport to the power plant. Stage #2 includes all construction and operation activities necessary to

move fuel from the extraction and processing point to the power plant, and ends at the power plant gate. The boundary of the upstream inventory of natural gas does not include the distribution system of natural gas to small end users, but rather is representative of delivery to a large end user such as a power plant or even a city gate.

The second piece of this analysis is a cradle-to-grave context to compare the greenhouse gas emissions of natural gas extraction and transport with those of electricity production and transmission. Neither piece of analysis includes the use of the produced product, but rather ends when the product is delivered. Coal-fired power systems are used as a further point of comparison.

Figure 2-1: Life Cycle Stages and Boundary Definitions



2.2 Basis of Comparison (Functional Unit)

To establish a basis for comparison, the LCA method requires specification of a functional unit, the goal of which is to define an equivalent service provided by the systems of interest. Within the cradle-to-gate boundary of this analysis, the functional unit is 1 MMBtu of fuel delivered to the gate of an energy conversion facility or other large end user. When the boundaries of the analysis are expanded to include power production, the functional unit is the delivery of 1 MWh of electricity to the consumer. In both contexts, the period over which the service is provided is 30 years.

2.2.1 Global Warming Potential

Greenhouse gases in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (Forster, et al., 2007). The default GWP used is the 100-year time frame, but in some cases, results for the 20-year time frame are presented as well. Selected results comparing all three time frames are included in the Appendix. **Table 2-1** shows the GWPs used for the greenhouse gases inventoried in this study.

Table 2-1: IPCC Global Warming Potentials (Forster, et al., 2007)

GHG	20-year	100-year (Default)	500-year
CO_2	1	1	1
CH_4	72	25	7.6
N_2O	289	298	153
SF_6	16,300	22,800	32,600

2.3 Representativeness of Inventory Results

This inventory uses data gathered from a variety of sources, each of which represents a particular temporal period, geographic location, and state of technology. Since the results of this study are the combination of each of those sources, this section discusses what the results of this study represent in each of those categories.

2.3.1 Temporal

The natural gas upstream inventory results best represent the year 2009, because of the use of the 2009 EIA natural gas production data to create the mix of natural gas sources in the domestic average result and well production rates for each source of natural gas. The year-over-year change to that mix of natural gas sources is small, and the results could represent a period from 2004 to 2012.

This study does not attempt to forecast technological advances or market shifts that might significantly change production rates or emissions of less mature formations.

The inventory results through the conversion of fuel to electricity represent the year 2010 for NETL system study-based technologies and the year 2007 for the fleet average values for coal and natural gas, since this is the vintage of the latest eGRID data release (EPA, 2010). Again, there would be little year-over-year change to the information, and so this LCA could reasonably represent a longer time period, from 2004 to 2015.

Some information included in this inventory pre-dates the temporal period stated above, but was determined to be the latest or highest quality available data.

The time frame of this study is 30 years, but that does not accurately represent a well drilled 30 years from now and operating 60 years into the future. An assumption is made about resource availability based on current estimated ultimate recovery values, and forecasts from the Energy Information Administration (EIA).

2.3.2 Geographic

The results of this inventory are representative of the lower 48 United States. Natural gas from Alaska is neither explicitly included nor excluded, nor are imports and exports. In some situations, source data may not break out information about geographic location, and so is implicitly included in this inventory. However, the error associated with this type of inclusion—or exclusion—is small.

2.3.3 Technological

The natural gas upstream inventory results include two distinct technological representations. The first is a baseline result which represents average 2009 natural gas production, including production from older, less productive wells. Production data from that year is used to create an average domestic mix of natural gas sources, and the production rate of each source well is generally based on 2009 well count and production data. The second set of results is representative of a new marginal unit of natural gas produced in 2009; these results use a variety of methods to create production rates for wells which would create the next unit of natural gas.

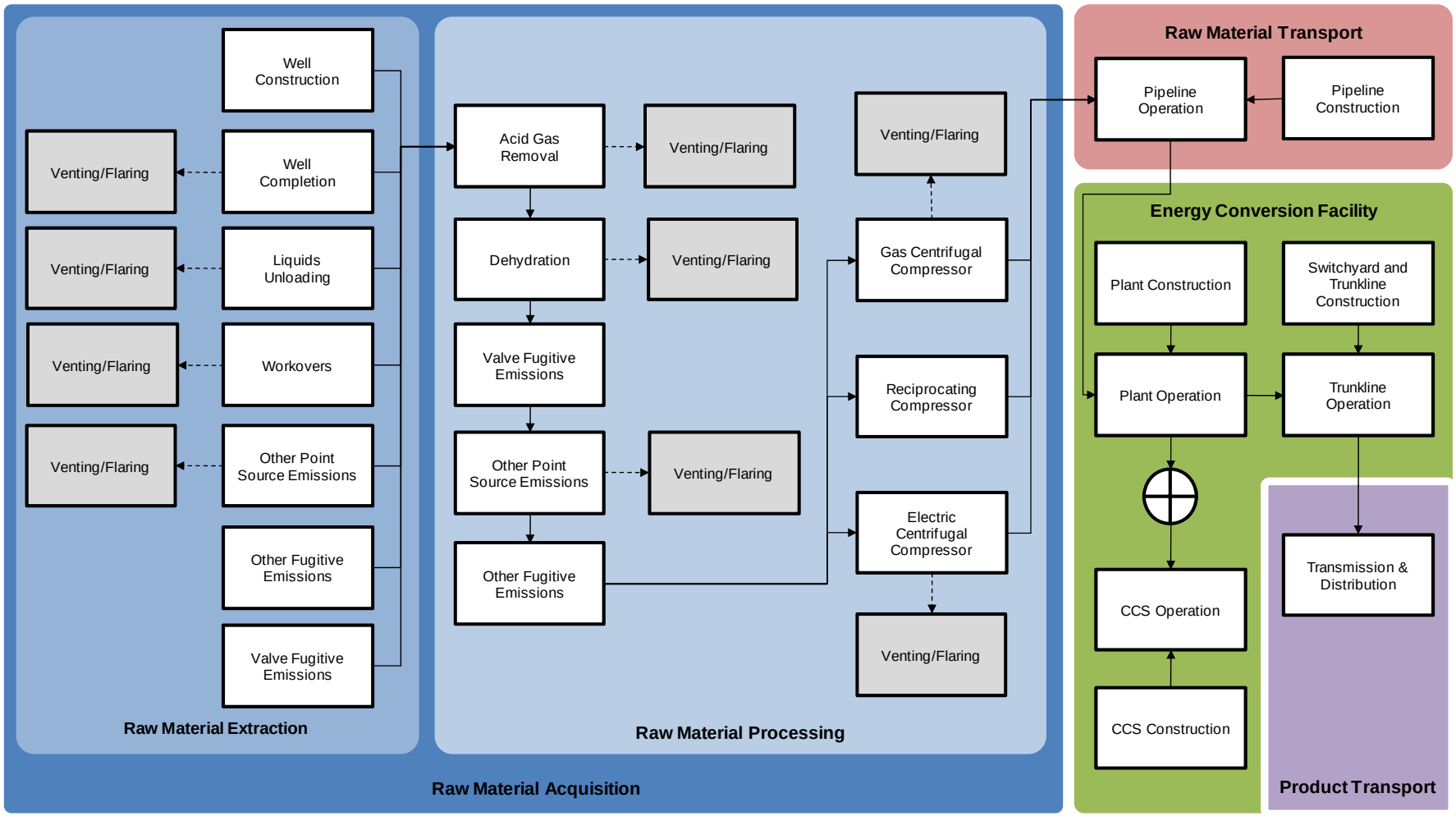
The results of this inventory are representative of currently installed technology as of 2011. This installed base is different from current technology because it includes much older equipment that is still operating.

2.4 Model Structure

All results for this inventory were calculated by NETL's LCA model for natural gas power systems. This model is an interconnected network of operation and construction blocks. Each block in the model, referred to as a unit process, accounts for the key inputs and outputs of an activity. The inputs of a unit process include the purchased fuels, resources from nature (fossil feedstocks, biomass, or water), and man-made raw materials. The outputs of a unit process include air emissions, water effluents, solid waste, and product(s). The role of an LCA model is to converge on the values for all intermediate flows within the interconnected network of unit processes and then scale the flows of all unit processes to a common basis, or functional unit.

The network of unit processes used for the modeling of natural gas power is shown in **Figure 2-2**. Note that only the RMA and RMT portions of the model are necessary to determine the upstream environmental burdens of natural gas; a broader scope—from raw material acquisition through delivery of electricity—is necessary to determine the cradle-to-grave environmental burdens of natural gas power. For simplicity, the following figure shows the extraction and delivery for a generic natural gas scenario; NETL's actual model uses six parallel modules to arrive at the life cycle results for a mix of six types of natural gas. This figure also shows a breakdown of the RMA stage into extraction and processing sub-stages.

Figure 2-2: Natural Gas LCA Modeling Structure



2.5 Data

The primary unit processes of this model are based on data compiled by NETL. Secondary unit processes, such as production of construction materials besides steel, are based on third party data. A full description of data sources is available in the Appendix.

Where data for the inventory is available, high and low values are collected, along with a nominal value. When results are presented, three cases are shown: a nominal case, a high case and a low case. The high and low results (error bars on the results) are a deterministic representation of the variability on the data and not indicative of an underlying distribution or likelihood.

2.5.1 Sources of Natural Gas

This inventory and analysis includes results for natural gas domestically extracted from six sources in the lower 48 states:

1. Conventional onshore
2. Associated
3. Conventional offshore
4. Tight sands
5. Shale formations (Barnett)
6. Coal bed methane

This is not a comprehensive list of natural gas extracted or consumed in the United States. Natural gas extracted in Alaska, 2 percent of domestically extracted natural gas, is included as conventional onshore production. The Haynesville shale play makes up a large portion of unconventional shale production, but it is assumed here that the Barnett play is representative of all shale production. Imported natural gas (18 percent of 2009 total consumption, 88 percent of which is imported via pipeline from Canada) is not included. About 12 percent of imports in 2009 were brought in as liquefied natural gas (LNG) from a variety of countries of origin. While this inventory includes a profile for LNG from offshore extraction in Trinidad and Tobago, this natural gas is not included in the domestic production mix.

Table 2-2 shows the makeup of the domestic production mix in the United States in 2009 and the mix of conventional and unconventional extraction. Note that in 2009 unconventional natural gas sources make up 56 percent of production and the majority of consumption in the Unites States (EIA, 2011a).

Table 2-2: Mix of U.S. Natural Gas Sources (EIA, 2011a)

Source	Conventional			Unconventional		
	Onshore	Associated	Offshore	Tight	Shale	CBM
Domestic Mix	25%	13%	7%	31%	16%	9%
Type Mix	44%			56%		
	56%	15%	29%	56%	28%	15%

The characteristics of these six sources of natural gas are summarized next, including a description of the extraction technologies.

2.5.1.1 Onshore

Conventional onshore natural gas is recovered by vertical drilling techniques. Once a conventional onshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. Compressors are used to move natural gas

through all process equipment and pressurize it for pipeline transport. Approximately 25 percent (5.2 TCF) of U.S. natural gas production is from conventional onshore gas wells (EIA, 2011a).

An intermittent procedure called liquids unloading is performed at mature onshore conventional natural gas wells to remove water and other liquids from the wellbore; if these liquids are not removed, the flow of natural gas is impeded. Another intermittent activity is a well workover, which is necessary to repair damage to the wellbore and replace downhole equipment, if necessary.

Natural gas is lost through intentional venting, which may be necessary for safety reasons, during well completion when natural gas recovery equipment or gathering lines have not yet been installed, or when key process equipment is offline for maintenance. When feasible, vented natural gas can be recovered and flared, which reduces the global warming potential of the vented natural gas by converting methane to carbon dioxide. Losses of natural gas also result from fugitive emissions due to the opening and closing of valves, and processes where it is not feasible to use vapor recovery equipment.

2.5.1.2 Offshore

Conventional offshore natural gas is recovered by vertical drilling techniques, similar to onshore. Once a conventional offshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. A natural gas reservoir must be large in order to justify the capital outlay for the completion of the well and construction of an offshore drilling platform, so production rates tend to be very high. Approximately 13 percent (2.7 TCF) of the United States natural gas supply in 2009 was from the conventional extraction from offshore natural gas wells (EIA, 2011a).

2.5.1.3 Associated

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated natural gas is similar to the extraction methods for conventional onshore natural gas (discussed above). Similar to conventional onshore and offshore natural gas wells, associated natural gas extraction includes losses due to well completion, workovers, and fugitive emissions. Since the natural gas is co-produced with petroleum, the use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Another difference between associated natural gas and other conventional natural gas sources is that liquid unloading is not necessary for associated natural gas wells because the flow of petroleum prevents the accumulation of liquids in the well. Approximately 7 percent (1.4 TCF) of U.S. natural gas production is from conventional onshore oil wells (EIA, 2011a). The majority of these wells are in Texas and Louisiana (EIA, 2010).

2.5.1.4 Tight Gas

The largest single source of domestically produced natural gas, and the largest share of unconventional natural gas, is tight gas. From naturalgas.org, tight gas is defined as follows:

> …trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). In a conventional natural gas deposit, once drilled, the gas can usually be extracted quite readily, and easily. A great deal more effort has to be put into extracting gas from a tight formation. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing. However, these techniques are also very costly. Like all unconventional natural gas, the economic incentive must be there to incite

companies to extract this costly gas instead of more easily obtainable, conventional natural gas (NGSA, 2010).

Approximately 31 percent (6.6 TCF) of natural gas produced domestically is from tight deposits. This analysis assumes tight gas wells are vertically drilled and hydraulically fractured.

2.5.1.5 Shale

Natural gas is also dispersed throughout shale formations, such as the Barnett Shale region in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracking). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracking uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale formation and facilitating the flow of natural gas. Hydrofracking is performed during the original completion of a shale gas well, but due to the steeply declining production curves of shale gas wells, hydrofracking is also performed during the workover of shale gas wells. Unlike conventional natural gas wells, shale gas wells do not require liquid unloading because wellbore liquids are reduced during workover operations. Natural gas from shale formations accounts for approximately 16 percent (3.3 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.1.6 Coal Bed Methane

Natural gas can be recovered from coal seams through the use of shallow horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed by a depressurization period during which naturally-occurring water is discharged from the coal seam. Coal bed methane (CBM) wells do not require liquid unloading and the emissions from CBM workovers are similar to those for shale gas wells. The production of natural gas from CBM wells accounts for approximately 9 percent (1.8 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.2 Natural Gas Composition

Relevant to all phases of the life cycle, the composition of natural gas varies considerably depending on source, and even within a source. For simplicity, a single assumption regarding natural gas composition is used, although that composition is modified as the natural gas is prepared for the pipeline (EPA, 2011a). **Table 2-3** shows the composition on a mass basis of production and pipeline quality natural gas. The pipeline quality natural gas has had water and acid gases (CO_2 and H_2S) removed, and non-methane VOCs either flared or separated for sale. The pipeline quality natural gas has higher methane content per unit mass. The energy content does not change significantly.

Table 2-3: Natural Gas Composition on a Mass Basis

Component	Production	Pipeline Quality
CH_4 (Methane)	78.3%	92.8%
NMVOC (Non-methane VOCs)	17.8%	5.54%
N_2 (Nitrogen)	1.77%	0.55%
CO_2 (Carbon dioxide)	1.51%	0.47%
H_2S (Hydrogen Sulfide)	0.50%	0.01%
H_2O (Water)	0.12%	0.01%

2.5.3 Data for Natural Gas Extraction

This analysis models the extraction of natural gas by characterizing key construction and operation activities at the natural gas wellhead. A summary of each unit process of NETL's model of natural gas extraction is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for these unit processes.

2.5.3.1 Well Construction

Data for the construction and installation of natural gas wellheads are based on the energy requirements and linear drill speed of diesel-powered drilling rigs, the depths of wells, and the casing materials required for a wellbore. Construction and installation are one-time activities that are apportioned to each unit of natural gas operations by dividing all construction and installation emissions by the lifetime in years and production in million cubic feet of a typical well.

2.5.3.2 Well Completion

The data for well completion describe the emission of natural gas that occurs during the development of a well, before natural gas recovery and other equipment have been installed at the wellhead. Well completion is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from an event that occurs one time in the life of a well.

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a).

Within the unconventional well category, NETL adjusted EPA's completion emission factors to account for the different reservoir pressures of unconventional wells. NETL used EPA's emission factor of 9,175 Mcf of methane per completion for Barnett Shale gas wells. NETL adjusted this emission factor downward for tight gas in order to account for the lower reservoir pressures of tight gas wells. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor. The production rate of tight gas wells is 40 percent of that for Barnett Shale wells (with EURs of 1.2 BCF for tight gas vs. 3.0 BCF for Barnett Shale), and thus NETL assumes that the completion emission factor for tight gas wells is 3,670 Mcf of methane per completion (40 percent × 9,175 = 3,670).

CBM wells also involve unconventional extraction technologies, but have lower reservoir pressures than shale gas or tight gas wells. The corresponding emission factor of CBM wells is 49.57 Mcf of methane per completion, which is the well completion factor that EPA reports for low pressure wells (EPA, 2011a).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. For instance, when factoring for the density of natural gas, a conventional completion emission of 36.65 Mcf is equivalent to 1,540 lbs. CH_4/completion.

2.5.3.3 Liquid Unloading

The data for liquids unloading describe the emission of natural gas that occurs when water and other condensates are removed from a well. These liquids impede the flow of natural gas from the well, and thus producers must occasionally remove the liquids from the wellbore. Liquid unloading is necessary for conventional gas wells—it is not necessary for unconventional wells or associated gas

wells. Liquid unloading is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well.

The methane emissions from liquids unloading are based on the total unloading emissions from conventional wells in 2007, the number of active conventional wells in 2007, and the average frequency of liquids unloading (EPA, 2011a). The resulting emission factor for liquids unloading is 776 lb CH_4/episode.

2.5.3.4 Workovers

Well workovers are necessary for cleaning wells and, in the case of shale and tight gas wells, use hydraulic fracturing to re-stimulate natural gas formations. The workover of a well is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well. As stated in EPA's technical support document of the petroleum and natural gas industry (EPA, 2011a), conventional wells produce 2.454 Mcf of methane per workover. EPA assumes that the emissions from unconventional well workovers are equal to the emission factors for unconventional well completion (EPA, 2011a). Thus, for unconventional wells, this analysis uses the same emission factors for well completion (discussed above) and well workovers.

Unlike well completions, well workovers occur more than one time during the life of a well. For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

2.5.3.5 Other Point Source Emissions

Routine emissions from natural gas extraction include gas that is released from wellhead and gathering equipment. These emissions are referred to as "other point source emissions." This analysis assumes that a portion of these emissions are flared, while the balance is vented to the atmosphere. For conventional wells, 51 percent of other point source emissions are flared, while for unconventional wells, a 15 percent flaring rate is used (EPA, 2011a).

Data for the other point source emissions from natural gas extraction are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for onshore and offshore wells. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other point source emissions from natural gas extraction are shown in **Table 2-4**.

2.5.3.6 Other Fugitive Emissions

Routine emissions from natural gas extraction include fugitive emissions from equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions," and cannot be captured for flaring. Data for other fugitive emissions from natural gas extraction are based on EPA data for onshore and offshore natural gas wells (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other fugitive emissions from natural gas extraction are included in **Table 2-4**.

2.5.3.7 Valve Fugitive Emissions

The extraction of natural gas uses pneumatic devices for the opening and closing of valves and other control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction site, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from valves (and other pneumatically-operated devices) are based on EPA data for onshore and offshore gas wells (EPA, 2011a). EPA's data are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate. The emission factors for fugitive valve emissions from natural gas extraction are included in **Table 2-4**.

Table 2-4: Other Point Source and Fugitive Emissions from Natural Gas Extraction

NG Extraction Emission Source	Onshore Extraction	Offshore Extraction	Units
Other Point Source Emissions	7.49E-05	3.90E-05	lb CH_4/lb NG extracted
Other Fugitive Emissions	1.02E-03	2.41E-04	lb CH_4/lb NG extracted
Valve Fugitive Emissions (including pneumatic devices)	2.63E-03	1.95E-06	lb CH_4/lb NG extracted

2.5.3.8 Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring at a natural gas well include carbon dioxide, methane, and nitrous oxide. The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.3 percent CH_4, 1.51 percent CO_2, 1.77 percent nitrogen, and 17.8 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). This composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2), the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2, and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4 Data for Natural Gas Processing

This analysis models the processing of natural gas by developing an inventory of key gas processing operations, including acid gas removal, dehydration, and sweetening. Standard engineering calculations were applied to determine the energy and material balances for the operation of key natural gas equipment. A summary of NETL's natural gas processing data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for NETL's natural gas processing data.

2.5.4.1 Acid Gas Removal

Raw natural gas contains hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas. Amine-based processes are the predominant technologies for acid gas removal (AGR). The energy consumed by an amine reboiler accounts for the majority of energy consumed by the AGR process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass of raw natural gas (Foss, 2004) is modeled in this analysis.

In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb of natural gas sweetened (API, 2009).

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and natural gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas.

Non-methane volatile organic compounds (NMVOCs) are a co-product of AGR. A mass balance shows that 84 percent of the vented gas from the AGR process is NMVOC. They are separated and sold as a high value product on the market. Co-product allocation based on the energy content of the natural gas stream exiting the AGR unit and the NMVOC stream was used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

2.5.4.2 Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

NETL's data for natural gas dehydration accounts for the reboiler used by the dehydration process, the flow rate of glycol solvent, and the methane vented from the regeneration of glycol solvent. All of these activities depend on the concentrations of gas and water that enter and exit the dehydration process. The typical water content for untreated natural gas is 49 lbs. per million cubic feet (MMcf). In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is three gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gallon (EPA, 2006).

2.5.4.3 Valve Fugitive Emissions

The processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery

equipment on all valves and other control devices at a natural gas processing plant, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from pneumatic devices are based on EPA data for gas processing plants (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific processing activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for valve fugitive emissions from natural gas processing is included in **Table 2-5**.

2.5.4.4 Other Point Source Emissions

Routine emissions from natural gas processing include gas that is released from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other point source emissions." This analysis assumes that 100 percent of other point source emissions from natural gas processing are captured and flared.

Data for the other point source emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other point source emissions from natural gas processing is included in **Table 2-5**.

2.5.4.5 Other Fugitive Emissions

Routine emissions from natural gas processing include fugitive emissions from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions." and cannot be captured for flaring.

Data for the other fugitive emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other fugitive emissions from natural gas processing is included in **Table 2-5**.

Table 2-5: Other Point Source and Fugitive Emissions from Natural Gas Processing

NG Processing Emission Source	Value	Units
Other Point Source Emissions	3.68E-04	lb CH_4/lb NG processed
Other Fugitive Emissions	8.25E-04	lb CH_4/lb NG processed
Valve Fugitive Emissions (including pneumatic devices)	6.33E-06	lb CH_4/lb NG processed

2.5.4.6 Venting and Flaring

The venting and flaring process for natural gas processing is similar to that of natural gas extraction, described in **Section 2.5.3.8**, except all of the other point source emissions at the natural gas processing plant are flared. The combustion products of flaring at a natural gas processing plant include carbon dioxide, methane, and nitrous oxide. The mass composition of pipeline quality natural gas is 92.8 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.5 percent NMVOCs; this composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2); the methane

emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2; and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4.7 Natural Gas Compression

Compressors are used to increase the natural gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. Three types of compressors are used at natural gas processing plants: gas-powered reciprocating compressors, gas-powered centrifugal compressors, and electrically-powered centrifugal compressors.

Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Burklin & Heaney, 2006).

Gas-powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures).

If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a populated area. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine.

Centrifugal compressors (both gas-powered and electrically-powered) lose natural gas through a process called wet seal degassing, which involves the regeneration of lubricating oil that is circulated between the compressor shaft and housing. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010) and implies a wet seal degassing emission factor of 0.0069 lb of natural gas/lb of processed natural gas.

2.5.5 Data for Natural Gas Transport

This analysis models the transport of natural gas by characterizing key construction and operation activities for pipeline transport. A summary of NETL's natural gas transport data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculation methods for NETL's natural gas transport data.

2.5.5.1 Natural Gas Transport Construction

The construction of a natural gas pipeline is based on the linear density, material requirements, and length for pipeline construction. A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Construction is a one-time activity that is apportioned to each unit of natural gas transport by dividing all construction burdens by the book life in years and throughput in million cubic feet of the pipeline.

2.5.5.2 Natural Gas Transport Operations

Data for the operation of a natural gas pipeline are based on national inventory data for methane emissions from natural gas transmission (EPA, 2011b) and a national pipeline compressor survey compiled by EIA (Gaul, 2011). Air emissions from pipeline operations are calculated by applying AP-42 emission factors to the portion of pipeline natural gas that is combusted for compressor power. Seven percent of U.S. natural gas pipeline compressors rely on electric power, and thus the emission profile of the U.S. electricity grid is used to model the emissions associated with electric compressor operations. Finally, the estimated transport capacity of U.S. national gas pipelines (in ton-miles) is applied to the other pipeline variables in order to correlate pipeline emissions with pipeline distance.

2.5.6 Data for Other Energy Sources

The overall goal of this analysis is to understand the greenhouse gas burdens of natural gas extraction and transport. However, the modeling of the conversion of natural gas energy to electricity and electricity transmission is necessary in order to understand how significant extraction and transport are in the cradle-to-grave life cycle context. Additionally, including a comparison both to the upstream greenhouse gases from coal extraction and transport, and the conversion of coal to electricity allows comparison of the fuels on a common basis.

Coal was chosen as a comparable fossil energy source to natural gas that will be used for power production. Because a mix of natural gas sources is developed to represent a domestic production average, a similar method was followed for developing an average domestic coal extraction and transport profile. Two sources of coal are used in the mix, and a wide range of uncertainty is applied to sensitive parameters to ensure the domestic average is captured. The two coal sources are:

- Illinois No. 6 Underground-mined Bituminous
- Powder River Basin Surface-mined Sub-bituminous

Table 2-6 shows the properties used for each type of coal, as well as the proportion of U.S. supply used to create the average profile. The methane content is indicative of what is emitted to the atmosphere during the mining process, not the methane contained in the coal in the formation or after mining.

Table 2-6: Coal Properties

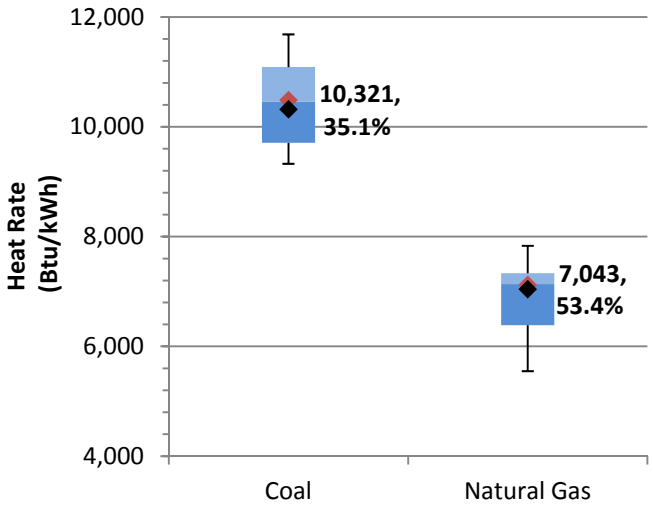
Coal Type	U.S. Supply Share (% by energy)	Energy Content (Btu/lb)	Carbon Content (% by mass)	Methane Emissions (cf CH_4/ton)
Sub-bituminous	69%	8,564	50.1%	8 – 98 (51)
Bituminous	31%	11,666	63.8%	360 – 500 (422)
Average		9,526	54.3%	

Additional information for the Illinois No. 6 profile can be found in the appendix and in the NETL document, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).* Additional information for the Powder River Basin coal extraction and transport profile can be found in the appendix to this document.

2.5.7 Data for Energy Conversion Facilities

The simplest way to compare the full life cycle of coal and natural gas is to produce electricity, although there are alternative uses for both feedstocks. To compare inputs of coal and natural gas on a common basis, production of baseload electricity was chosen. Seven different power plant options are used – three for natural gas and four for coal. Three of the options include carbon capture technology and sequestration infrastructure. Two of the options are U.S. fleet averages based on eGRID data, while the remainder are NETL baseline models. For the U.S. fleet average power plants, **Figure 2-3** shows the distribution of heat rates and associated efficiencies from eGRID. To arrive at the samples shown below, plants smaller than 200MW, with capacity factors lower than 60 percent, and with primary feedstock percentages below 85 percent were cut. The boxes are the first and third quartiles, and the whiskers the 5th and 95th percentiles. The division in the boxes is the median value. The black diamond is the mean, and the orange diamond is the production-weighted mean.

Figure 2-3: Fleet Baseload Heat Rates for Coal and Natural Gas (EPA, 2010)



2.5.7.1 Natural Gas Combined Cycle (NGCC)

The NGCC power plant is based a 555-MW thermoelectric generation facility with two parallel, advanced F-Class gas fired combustion turbines. Each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine. The NGCC plant consumes natural gas at a rate of 75,900 kg/hr and has an 85 percent capacity factor. Other details on the fuel consumption, water withdrawal and discharge, and emissions to are detailed in NETL's bituminous baseline (NETL, 2010a). The carbon capture scenario for NGCC is configured a Fluor Econamine carbon dioxide capture system that recovers 90 percent of the CO_2 in the flue gas

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant (NETL, 2010d).*

2.5.7.2 Gas Turbine Simple Cycle (GTSC)

The GTSC plant uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators. The performance of the GTSC plant was adapted from NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and not

accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW and it has an 85 percent capacity factor.

2.5.7.3 U.S. 2007 Average Baseload Natural Gas

The average baseload natural gas plant was developed using data from eGRID on plant efficiency (EPA, 2010). The most recent eGRID data is representative of 2007 electricity production. The average heat rate was calculated for plants with a capacity factor over 60 percent and a capacity greater than 200MW to represent those plants performing a baseload role. The average efficiency (weighted by production, so the efficiency of larger, more productive plants had more weight) was 53.4 percent. This heat rate is applied to the energy content of natural gas (which ranges from 990 and 1,030 Btu/cf) in order to determine the feed rate of natural gas per average U.S. natural gas power. Similarly, the carbon content of natural gas (which ranges from 72 percent to 80 percent) is factored by the feed rate of natural gas, 99 percent oxidation efficiency, and a molar ratio of 44/12 to determine the CO_2 emissions per unit of electricity generation.

2.5.7.4 Integrated Gasification Combined Cycle (IGCC)

The plant modeled is a 640 MW IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned before being fed to two advanced F-Class combustion turbine/generators. The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator. A syngas expander generates additional power.

This facility has a capacity factor of 80 percent. For the carbon capture case, the plant is a 556 MW facility with a two-stage Selexol solvent process to capture both sulfur compounds and CO_2 emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant (NETL, 2010c).*

2.5.7.5 Supercritical Pulverized Coal (SCPC)

This plant is a 550 MW facility located at a greenfield site in southeast Illinois utilizing a single-train supercritical steam generator. Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator. Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide, a combination of low-nitrogen oxides burners and overfire air, and a selective catalytic reduction unit that removes nitrogen oxides, a pulse jet fabric filter that removes particulates, and mercury reductions via co-benefit capture.

The carbon capture case is a 546 MW plant configured with 90 percent CCS utilizing an additional sulfur polishing step to reduce sulfur content and a Fluor Econamine FG Plus process. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).*

2.5.7.6 Existing Pulverized Coal (EXPC)

This case is an existing pulverized coal power plant that fires coal at full load without capturing carbon dioxide from the flue gas. This case is based on a 434 MW plant with a subcritical boiler that fires Illinois No. 6 coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. The net efficiency of this power plant is 35 percent.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant (NETL, 2010b).*

2.5.7.7 U.S. 2007 Average Baseload Coal

Using a similar method to the fleet average natural gas baseload plant, a mean and weighted average efficiency of 35.1 percent were pulled from eGRID. Using the coal characteristics detailed in **Table 2-6**, a feed rate and emissions rate were created.

For each option, the transmission and distribution (T&D) of electricity incurs a 7 percent loss, resulting in the production of additional electricity and extraction of necessary fuel to overcome this loss. All upstream life cycle stages scale according to this loss factor.

Construction is included in the four NETL developed models. It accounts for less than 1 percent of overall greenhouse gas impact, and so was excluded from the total for the fleet average plants.

The performance characteristics of the power plants modeled in this analysis are summarized in **Table 2-7**. Note that for the average natural gas and coal power plants, low, nominal and high values are indicated.

Table 2-7: Power Plant Performance Characteristics

Property		Natural Gas			Coal					
		NGCC	GTSC	Avg. NG	IGCC	IGCC (w/ CCS)	SCPC	SCPC (w/ CCS)	EXPC	Avg. Coal
Performance										
Net Output	MW	555	360	> 200	640	556	550	546	434	> 200
Heat Rate[1]	Btu/kWh L			7,334						11,090
	Btu/kWh N	6,798	11,323	7,043	8,756	10,458	8,687	12,002	9,749	10,321
	Btu/kWh H			6,387						9,708
Efficiency	% L			46.5%						30.8%
	% N	50.2%	30.1%	48.4%	39.0%	32.6%	39.3%	28.4%	35.0%	33.1%
	% H			53.4%						35.1%
Capacity Fac.	%	85%	85%	> 60%	80%	80%	85%	85%	85%	> 60%
Feedstocks										
Natural Gas	cf/MWh	6,619	11,025	6,858	-	-	-	-	-	-
Ill. No. 6 Coal	lb/MWh	-	-	-	730	876	745	1,036	734	649
PRB Coal	lb/MWh	-	-	-	-	-	-	-	-	355
Air Emissions										
CO_2	lb/MWh	804	1,100	817	1,723	206	1,768	244	2,075	1,999
CO_2 Capture	%	n/a	n/a	n/a	n/a	90%	n/a	90%	n/a	n/a

[1] L, N, H indicated Low, Nominal (default), and High values, respectively.

2.5.8 Summary of Key Model Parameters

The following table summarizes the key parameters that affect the life cycle results for the extraction of natural gas. This includes the amounts of methane emissions from routine activities, frequency and emission rates from non-routine operations, depths of different well types, flaring rates of vented gas, production rates, and domestic supply shares.

Table 2-8: Key Parameters for Six Types of Natural Gas Sources

Property (Units)	Onshore	Associated	Offshore	Tight Sands	Shale	CBM
Natural Gas Source						
Production Rate (Mcf/day) (Range)	66 (46 - 86)	121 (85 - 157)	2,800 (1,960 - 3,641)	110 (77 - 143)	274 (192 - 356)	105 (73 - 136)
Natural Gas Extraction Well						
Flaring Rate (%)	51% (41 - 61%)			15% (12 - 18%)		
Well Completion (Mcf/episode)	47			4,657	11,643	63
Well Workover (Mcf/episode)	3.1			4,657	11,643	63
Well Workover Frequency (Episode/well/yr)	1.1			3.5		
Liquids Unloading (Mcf/episode)	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading Frequency (Episodes/well)	930	n/a	930	n/a	n/a	n/a
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.11		0.0001	0.11		
Other Sources, Point Source (lb CH_4/Mcf)	0.003		0.002	0.003		
Other Sources, Fugitive (lb CH_4/Mcf)	0.043		0.01	0.043		
Acid Gas Removal (AGR) and CO_2 Removal Unit						
Flaring Rate (%)	100%					
CH_4 Absorbed (lb CH_4/Mcf)	0.04					
CO_2 Absorbed (lb CO_2/Mcf)	0.56					
H_2S Absorbed (lb H_2S/Mcf)	0.21					
NMVOC Absorbed (lb NMVOC/Mcf)	6.59					
Glycol Dehydrator Unit						
Flaring Rate (%)	100%					
Water Removed (lb H_2O/Mcf)	0.045					
CH_4 Emission Rate (lb CH_4/Mcf)	0.0003					
Valves & Other Sources of Emissions						
Flaring Rate (%)	100%					
Valve Emissions, Fugitive (lb CH_4/Mcf)	0.0003					
Other Sources, Point Source (lb CH_4/Mcf)	0.02					
Other Sources, Fugitive (lb CH_4/Mcf)	0.03					
Natural Gas Compression at Gas Plant						
Compressor, Gas-powered Reciprocating (%)	100%	100%		100%	75%	100%
Compressor, Gas-powered Centrifugal (%)			100%			
Compressor, Electrical, Centrifugal (%)					25%	
Natural Gas Emissions on Transmission Infrastructure						
Pipeline Transport Distance (mi.)	604 (483 - 725)					
Pipeline Emissions, Fugitive (lb CH_4/Mcf-mi.)	0.0003					
Natural Gas Compression on Transmission Infrastructure						
Distance Between Compressors (mi.)	75					
Compressor, Gas-powered Reciprocating (%)	78%					
Compressor, Gas-powered Centrifugal (%)	19%					
Compressor, Electrical, Centrifugal (%)	3%					

3 Inventory Results

This section includes upstream results for the average production case, marginal upstream results, and results after conversion to electricity.

3.1 Average Upstream Inventory Results

This analysis defines upstream activities as the raw material acquisition and transport activities that are necessary for the delivery of fuel to a power plant. The results of this analysis include the upstream GHG emissions for natural gas. For the natural gas supply chain, upstream includes well operations and natural gas processing activities, as well as the pipeline transport of natural gas from the extraction site to a power plant.

Figure 3-1: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source

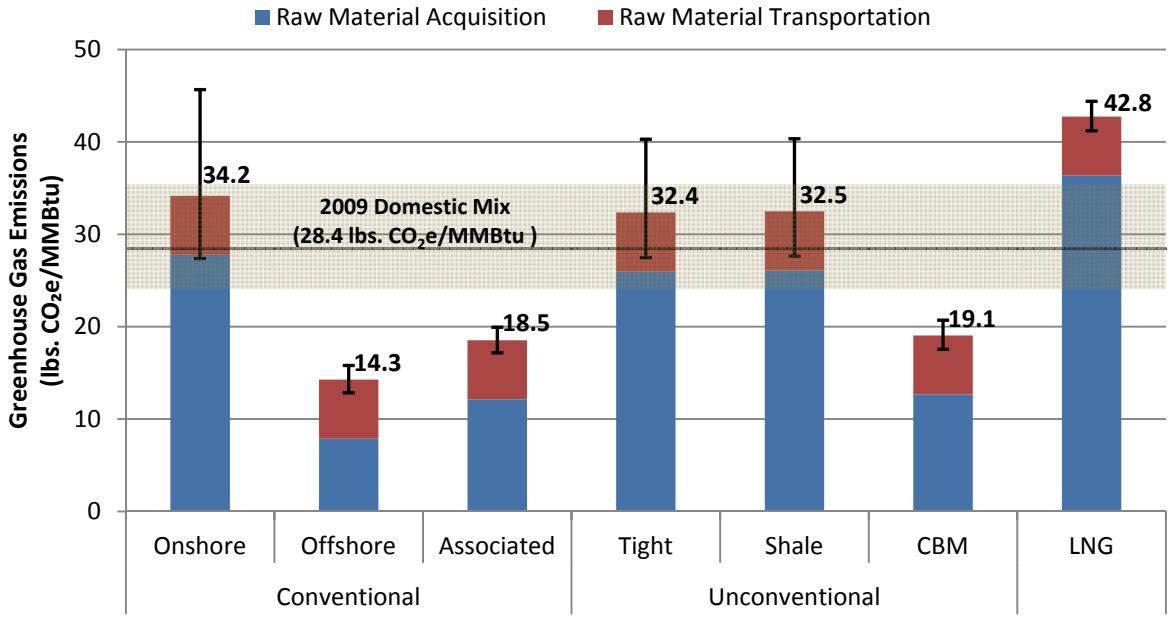


Figure 3-1 shows the comparative upstream greenhouse gases of the six sources of domestic gas, imported liquefied natural gas, and the 2009 mix of all of those sources, broken out by life cycle stage. These results are based on IPCC 100-year GWP. The domestic average of 28.4 lbs. CO_2e/MMBtu and its associated uncertainty are shown overlaying the results for the other types of gas. This average is calculated using the percentages shown in **Table 2-2**. It is worth noting here that the RMT result is the same for all types of natural gas. It is assumed in this study that natural gas is a commodity that is indistinguishable once put on the transport network, so the distance traveled is the same for all types of natural gas. The distance parameter is adjustable, so if a natural gas type with a short distance to markets were evaluated, the RMT value would be smaller.

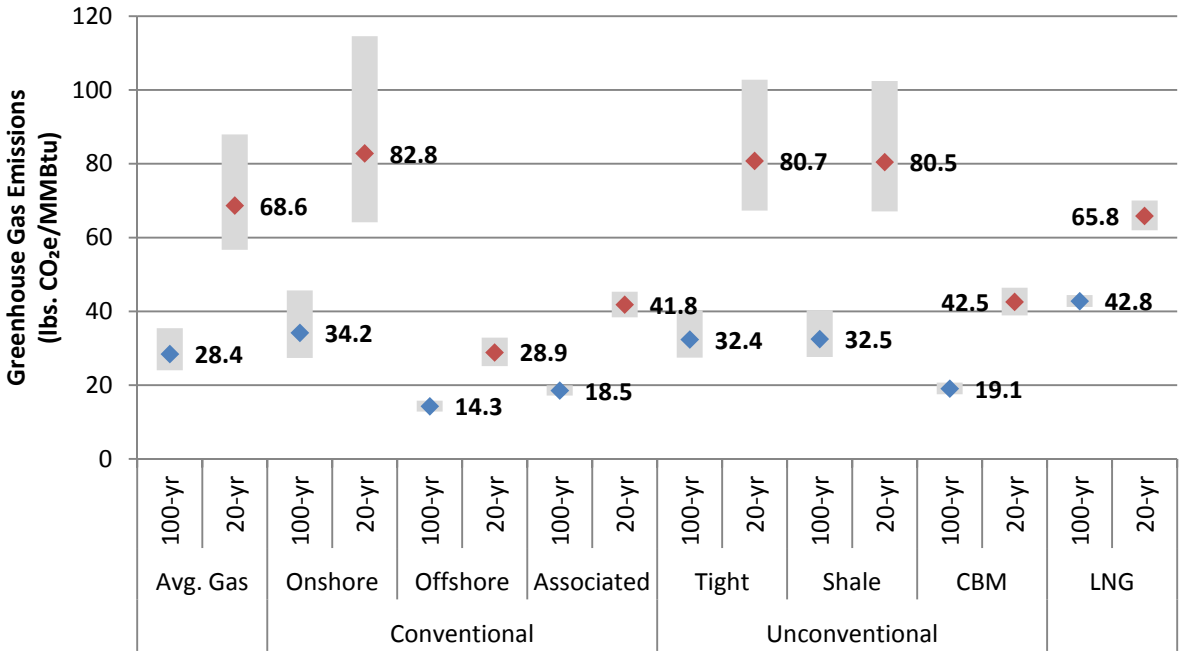
Offshore sourced natural gas has the lowest greenhouse gases of any source. This is due to the very high production rate of offshore wells and an increased emphasis on controlling methane emissions for safety and risk-mitigation reasons.

Imported gas has a significantly higher greenhouse gases than even domestic unconventional extraction. It is fundamentally an offshore extraction process, which has the lowest GHGs of all the

sources. The additional impact is due to the refrigeration, ocean transport and liquefaction processes. Uncertainty is highest for the unconventional sources due to high episodic emissions (well completions, workovers, etc.) and a wide range of observed production rates to allocate those emissions.

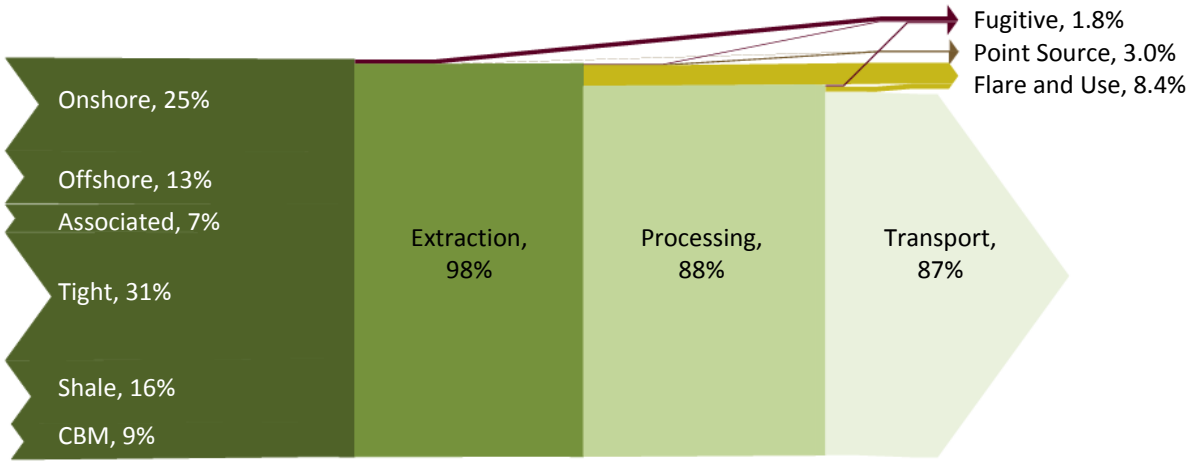
The key sources of GHG emissions in the natural gas supply chain are the combustion of fossil fuels and the venting of methane from natural gas processing and compression equipment.

Figure 3-2: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source and GWP



The results in **Figure 3-2** compare the basic results from **Figure 3-1** across two sets of global warming potentials (detailed in **Table 2-1**). Converting the inventory of greenhouse gases to 20-year GWP, where methane's factor increases from 25 to 72, magnifies the difference between conventional and unconventional sources of natural gas, and the importance of methane losses to the cradle-to-gate GHG results.

Figure 3-3: Cradle-to-Gate Reduction in Extracted Natural Gas



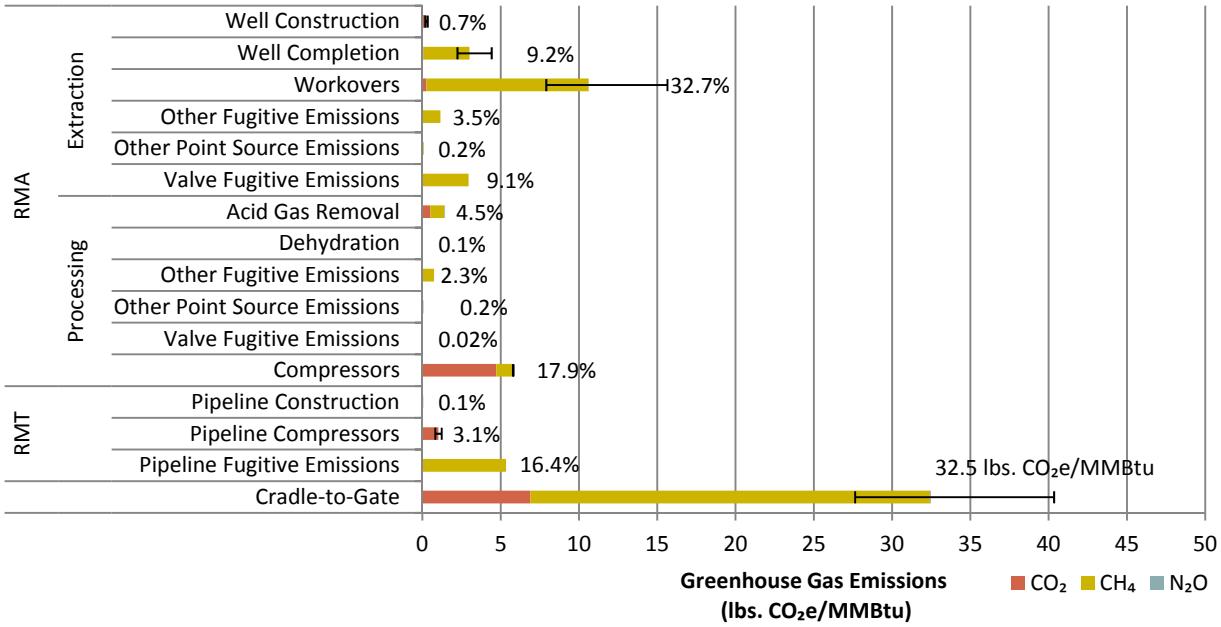
The Sankey diagram shown in **Figure 3-3** shows the reduction in natural gas (not solely methane) from extraction to delivery at the plant gate. This information is also not weighted by global warming potential. **Table 3-1** shows the same information in table form. Of the natural gas extracted from the ground, only 87 percent is delivered to the plant or city gate; 13 percent is either used internally for power, released at a point source and then flared – if applicable, or lost as a fugitive emission. It is important to recognize that not all of this gas is emitted to the atmosphere. In fact, 64 percent of the reduction in natural gas is used to power various processing equipment, most significantly compressors providing motive force for the natural gas. Further, 23 percent are point source emissions, generally concentrated enough to be flared; this, importantly from a climate change perspective, converts the methane to carbon dioxide. Only 13 percent of emissions are considered fugitive: spatially separated emissions difficult to capture or control.

Table 3-1: Natural Gas Losses from Extraction and Transportation

Process	Raw Material Acquisition		Transport	Total
	Extraction	Processing		
Extracted from Ground	100.0%			100.0%
Fugitive Losses	1.2%	0.1%	0.5%	1.8%
Point Source Losses (Vented or Flared)	0.8%	2.2%	0.0%	3.0%
Flare and Fuel Use	0.0%	7.6%	0.8%	8.4%
Delivered to End User				86.9%

By expanding the underlying data in NETL's model, a better understanding of the key contributions to natural gas emissions can be achieved. **Figure 3-4** shows the GHG contribution of specific extraction and transport activities for the Barnett Shale profile. This figure further shows the contribution of methane (CH_4), nitrous oxide (N_2O) and carbon dioxide (CO_2) to the total greenhouse gases. Similar data exists for each source of natural gas, as well as for the domestic average.

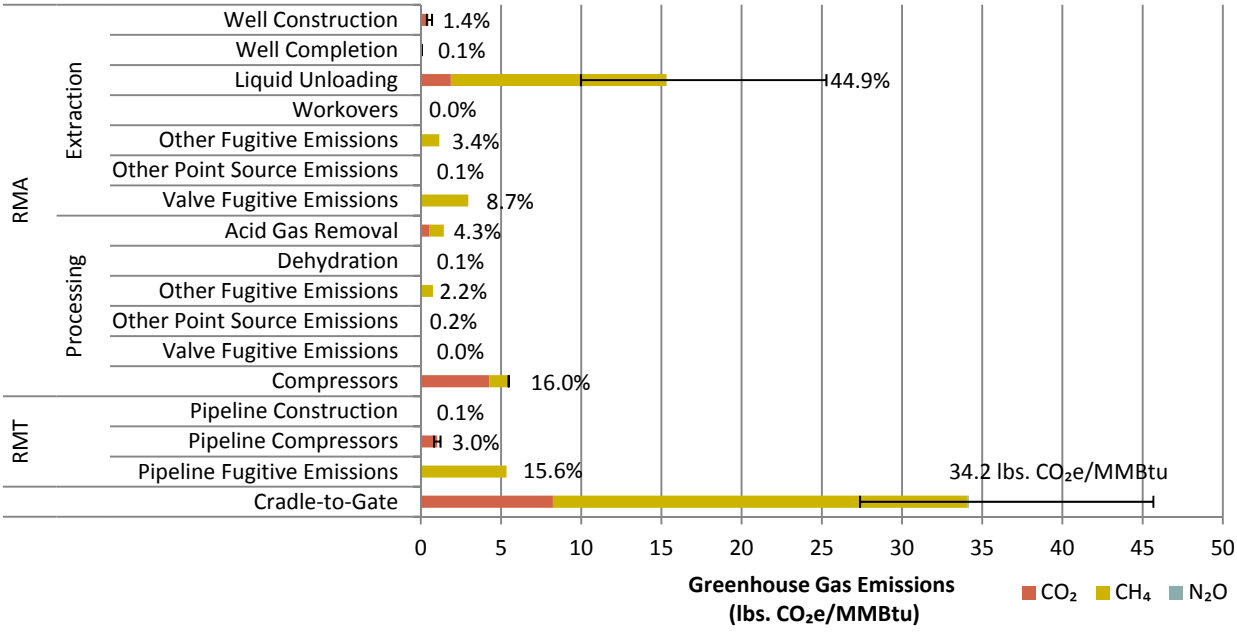
Figure 3-4: Expanded Greenhouse Gas Results for Barnett Shale Gas



This figure shows clearly how important methane is to the total greenhouse gas emissions. In most energy systems, carbon dioxide is the primary concern, but for natural gas extraction, processing and transport, the methane drives the result, and most of the uncertainty. With this unconventional gas, the importance (and associated uncertainty) associated with episodic emissions such as well completion and workover can be seen as well. Well construction, on the other hand, contributes less than 1 percent to the total. Moreover, from the compressors at the last stage of the processing step along with the compressor operations and fugitive emissions on the pipeline, the importance of transport can be seen from these results.

Figure 3-5 shows similar cradle-to-gate results for the natural gas extracted from conventional onshore wells. As with the shale profile, the major contributors are the fuel use and fugitive emissions from the transport, and episodic emissions like liquid unloading. Liquid unloading along contributes 45 percent to the total emissions, and the majority of the uncertainty as well. The uncertainty indicated here is due to a wide range in production rate, not the emission factor for liquids unloading. As discussed in the modeling method, production rate is used to apportion episodic emissions.

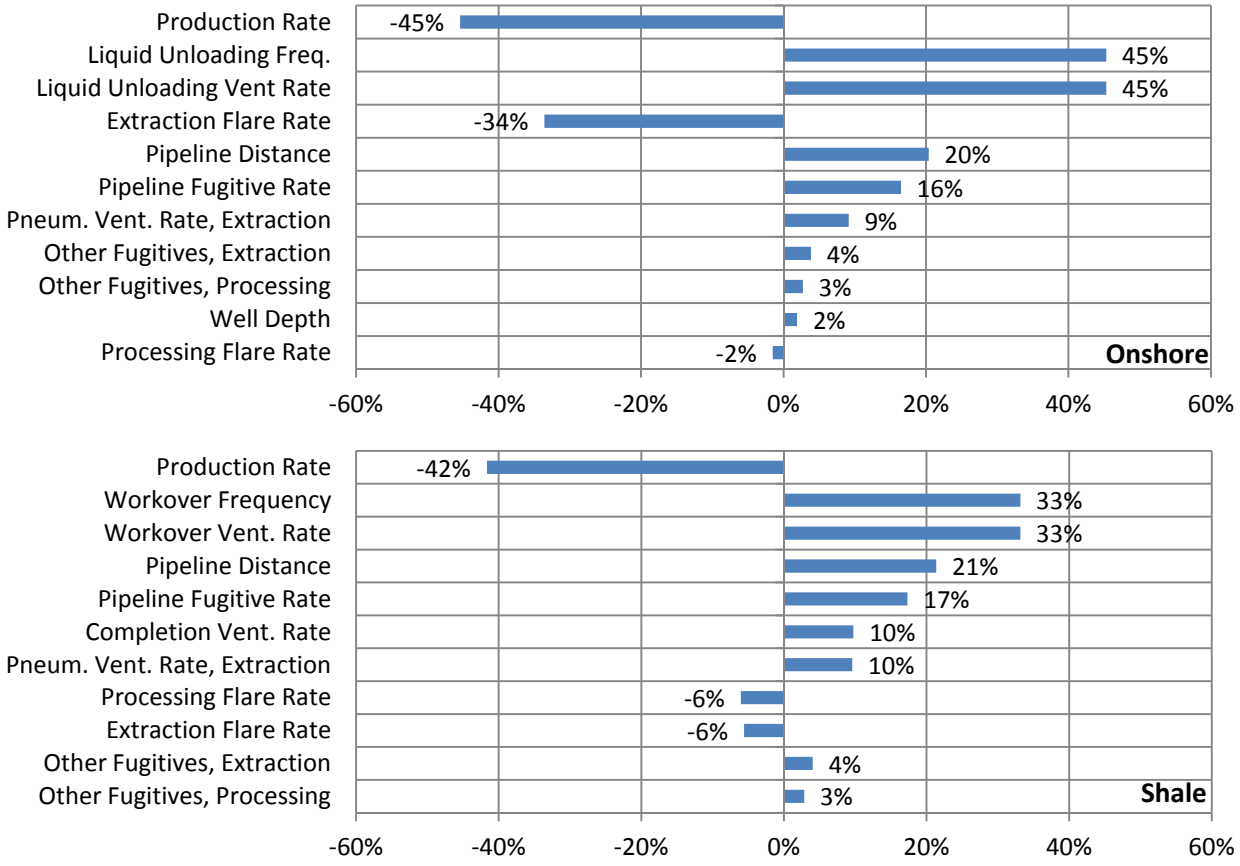
Figure 3-5: Expanded Greenhouse Gas Results for Onshore Natural Gas



This analysis uses a parameterized modeling approach that allows the alteration and subsequent analysis of key variables. Doing so allows the identification of variables that have the greatest effect on results. Sensitivity results are shown in **Figure 3-6**. Parameters were adjusted and displayed regardless of whether uncertainty information was collected for that parameter. Percentages above are relative to a unit change in parameter value; all parameters are changed by the same percentage, allowing comparison of the magnitude of change to the result across all parameters. Positive results indicate that an increase in the parameter leads to an increase in the result. A negative value indicates an inverse relationship; an increase in the parameter would lead to a decrease in the overall result.

For example, a 5 percent increase in shale Production Rate would result in a 2.1 percent (5 percent of 42 percent) decrease in cradle-to-gate GHGs, from 32.5 to 31.8 lbs. CO_2e/MMBtu. A corresponding 5 percent increase in onshore Production rate results in a 2.3 percent decrease to 33.4 lbs. CO_2e/MMBtu. Thus, onshore is more sensitive to changes in production rate than shale gas.

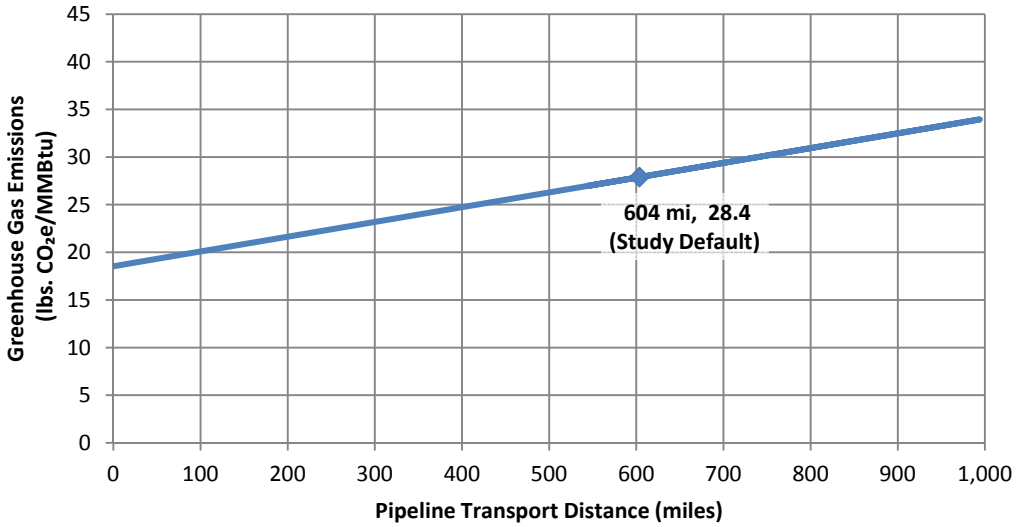
Figure 3-6: Sensitivity of Onshore and Shale GHGs to Changes in Parameters



The results in **Figure 3-6** show that both the onshore and shale profiles are sensitive to changes in pipeline distance, which is currently set to 604 miles for all profiles. As more unconventional sources like Marcellus shale which is close to major demand centers (New York, Boston, Toronto) come on the market, the average distance natural gas has to travel will go down, decreasing the overall impact.

The pipeline transport of natural gas is inherently energy intensive because compressors are required to continuously alter the physical state of the natural gas in order to maintain adequate pipeline pressure. Further, the majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline. **Figure 3-7** shows the sensitivity of natural gas losses to pipeline distance. The study default for domestic sources of natural gas is 604 miles, which was determined by solving for the distance at which the per-mile emissions were equivalent to the U.S. annual natural gas transmission methane emissions in 2009. See **Appendix A** for full discussion on determining a default distance.

Figure 3-7: Sensitivity of GHGs Results to Pipeline Distance



3.2 Results for Marginal Production

Marginal production is defined here as the next unit of natural gas produced not included in the average, presumably from a new, highly productive well for each type of natural gas. Since older, less productive wells are ignored as part of these results, the production rate per well is much higher, episodic emissions are spread across more produced gas, and the corresponding GHG inventory is lower. **Table 3-2** shows the production rate assumptions used for both the average and marginal cases.

Table 3-2: Production Rate Assumptions for Average and Marginal Cases

Source	Well Count	Dry Production (Tcf)	Production Rate (Mcf/day)					
			Average			Marginal		
			N	L (-30%)	H (+30%)	N	L (-30%)	H (+30%)
Onshore	216,129	5.2	66	46	86	593	297	1,186
Offshore	2,641	2.7	2,801	1,961	3,641	6,179	3,090	12,358
Associated	31,712	1.4	121	85	157	399	200	798
Tight Sands	162,656	6.6	111	78	144	110	77	143
Shale	32,797	3.3	274	192	356	274	192	356
CBM	47,165	1.8	105	73	136	105	73	136

Results are shown below in **Table 3-3**. The marginal and average production rates for the unconventional sources (tight, shale and CBM) were identical, and so there is no change shown below. There was a significant change in the production rate for all the mature conventional sources. Large numbers of the wells from each of these sources are nearing the end of the useful life, and have dramatically lower production rates, bringing the average far below what would be expected of a new well of each type.

Table 3-3: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

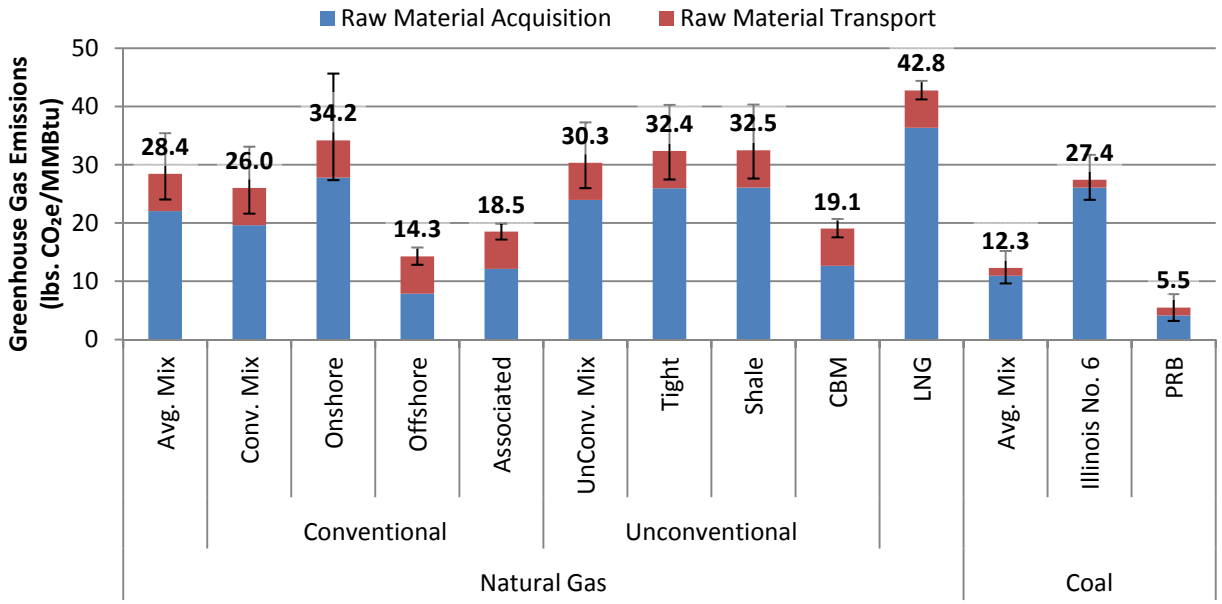
Interestingly, although the production rates for both associated gas and offshore gas change significantly, there is little change to the upstream value: a drop of 0.8 percent and 1.4 percent respectively. This has to do with the characteristics of these types of wells; the flow of natural gas in offshore wells is so strong that there is no need to periodically perform liquids unloading, and for associated wells, the petroleum co-product is constantly removing any liquid in the well. This means the only episodic emission (one which would need to be allocated by lifetime production of the well) is the construction or completion of the well, which is small in both cases, as a percentage of overall emissions.

That leaves onshore conventional production as the only source which shows a significant difference (a drop of 41.2 percent) between the average and marginal production. There are over 200,000 active onshore conventional wells, over 80 percent of which have daily production below the average rate of 138 Mcf/day (EIA, 2010). Yet, when this marginal natural gas is run through electricity generation, there is only a 7 percent drop in greenhouse gas emissions.

3.3 Comparison to Other Fossil Energy Sources

Additional insight can be gained by comparing the life cycle of natural gas power to those of coal. The upstream GHG emissions for various fuels are shown in **Figure 3-8**.

Figure 3-8: Comparison of Upstream GHG Emissions for Various Feedstocks

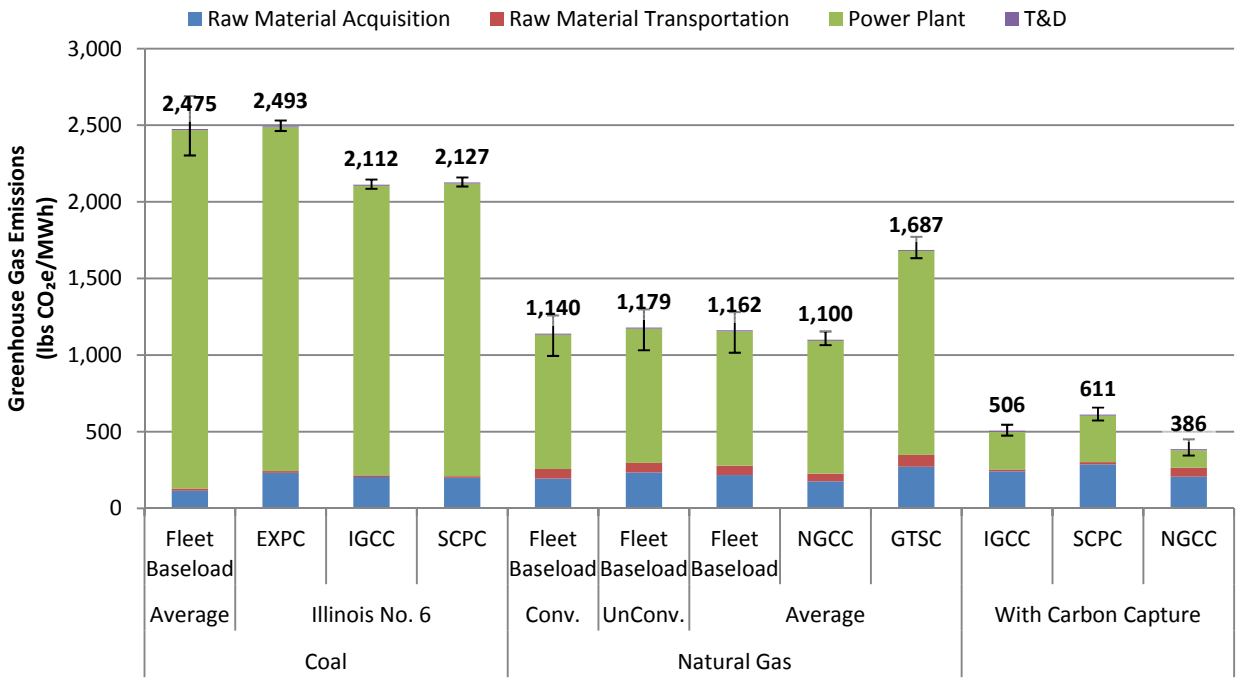


Compared on an upstream energy basis, natural gas has higher GHG emissions than coal. Comparing the domestic mixes from **Figure 3-8**, natural gas is nominally 116 percent more greenhouse gas intense than coal. Gassier bituminous coal such as Illinois No. 6 is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

3.4 Role of Energy Conversion

The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than it is out of natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels, and as such, different bases on which they could be compared. However, in the United States, the vast majority of coal is used for power production, and so provides the most relevant comparison. **Figure 3-9** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer. In addition to the NETL baseline fossil plants with and without carbon capture and sequestration, these results include a simple cycle gas turbine (GTSC) and representations of fleet average baseload coal and natural gas plants, as described in **Section 2.5.7**.

Figure 3-9: Life Cycle GHG Emissions for Electricity Production



In contrast to the upstream results, which showed a significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. Even when using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer greenhouse gases emitted than for coal-fired power. Because of different the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 2,475 lbs. CO_2e/MWh, more than double the emissions of the natural –gas fired plant at 1,162 lbs. CO_2e/MWh.

Figure 3-10 shows the same results but applying and comparing 100- and 20-year IPCC global warming potentials to the inventoried greenhouse gases.

Figure 3-10: Comparison of Power Production GHG Emissions on 100- and 20-year GWPs

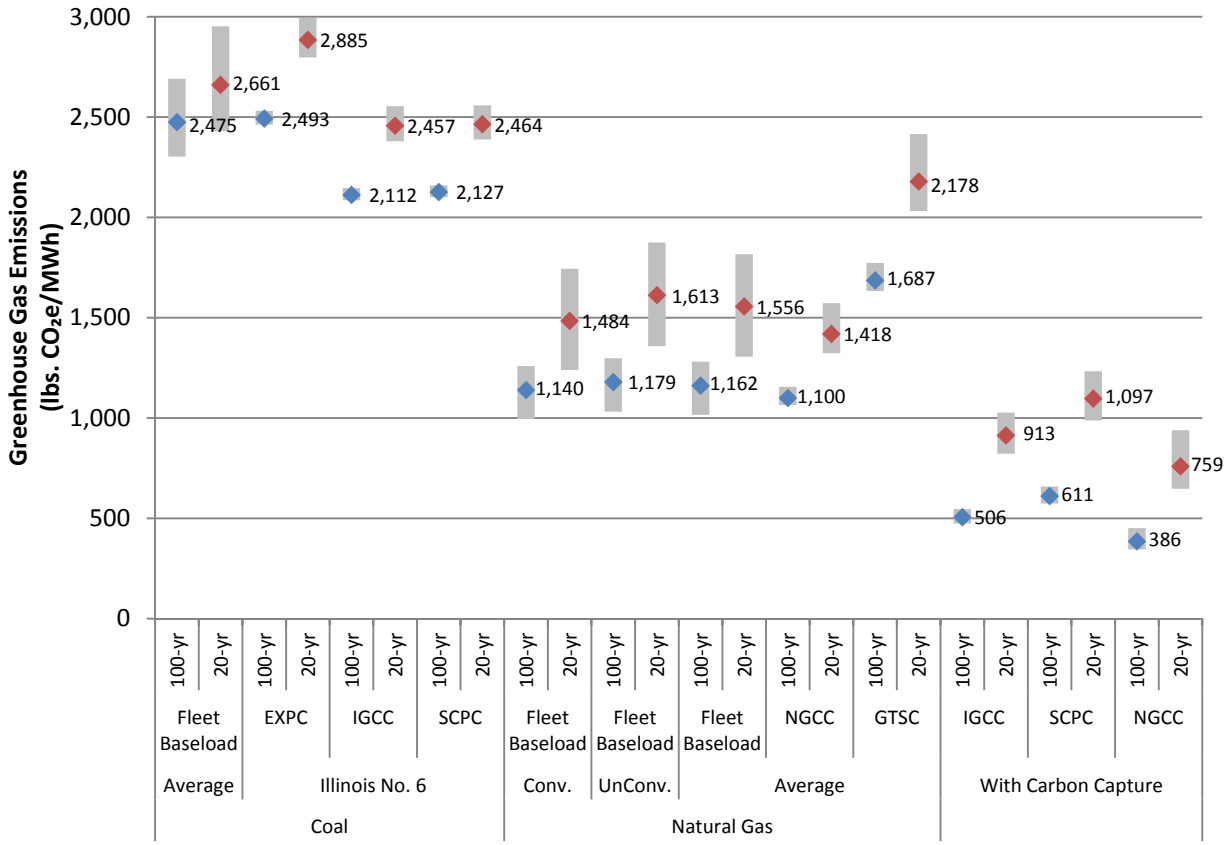


Figure 3-10 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an IGCC unit with carbon capture. The high end of the range overlaps the nominal value for IGCC in this situation.

4 Discussion

The following section contains a comparison of the results of this analysis to other natural gas LCAs, a discussion on data limitations, recommendations for improvement and final conclusions.

4.1 Comparison to Other Natural Gas LCAs

Authors at universities and other government labs have conducted research on the natural gas life cycle. The methods and conclusions of three such papers are summarized below.

Life Cycle Assessment of a Natural Gas Combined Cycle Power Generation System (Spath & Mann, 2000)

This NREL study is somewhat dated, having been published in 2000, but using data from the 1990s. It is a high quality study, which makes solid assumptions and tests those assumptions with documented sensitivity analysis. It uses national, annual, top-down information to develop the upstream emissions for natural gas extraction and transportation. Because of this, there are no data specific to unconventional extraction. This study includes not only greenhouse gases but select criteria air emissions and an energy balance. A qualitative impact assessment is performed as well.

Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation (Jaramillo, Griffin, & Matthews, 2007)

This widely cited paper is the most recent publicly available, peer-reviewed study that directly compares life cycle greenhouse gas emissions of power generated from natural gas and coal. Due to concerns regarding gas price volatility at the time the paper was being written, it also includes a comparison of LNG and synthetic natural gas (SNG) from coal. Rather than attempting to represent the next megawatt-hour generated by using best available technology, it looks at average current megawatt-hours generated, so plant efficiencies tend to be lower and emission factors higher. It mixes technologies (NGCC vs. GTSC) and roles (baseload vs. peaking). Like the NREL study, the upstream emissions for both natural gas and coal are top-down numbers. These values are somewhat dated, and represent a homogeneous gas supply rather than breaking out unconventional extraction.

Development of a Top Down Screening Model Using 2011 EPA Greenhouse Gas Inventory

Although this study uses emission factors from the EPA that went into building the 2011 U.S. Greenhouse Gas Inventory, it did not use the annual emissions estimates to generate a top-down value. Rather, some of the EPA emission factors were applied against specific activities, combined with other data sources and standard engineering calculations in a comprehensive hybrid bottom-up approach.

For comparison purposes, NETL performed a top-down analysis of 2009 domestic natural gas production using EPA's 2011 GHG inventory. This top-down approach was not a comprehensive LCA, but was a screening method that resulted in an aggregated, national-level estimate of GHG emissions. The top-down approach gave a GHG result of 36.6 lbs. CO_2e/MMBtu of delivered natural gas to a large end user, with +30 percent and -19 percent uncertainty. NETL's comprehensive LCA model of natural gas gives a GHG result of 28.4 lbs. CO_2e/MMBtu of delivered natural gas, which is 24 percent lower than the top-down value derived from EPA's national inventory. The nominal top-down number from EPA's inventory is within NETL's uncertainty range, but NETL and EPA use many of the same emission factors for natural gas production, and thus an explanation of the 24 percent difference is necessary.

An overarching reason for the difference between EPA's national inventory and NETL's natural gas life cycle analysis model is that EPA's inventory is based on the emissions reported for an entire industry sector over one year, while NETL's model accounts for the operating characteristic of six types of natural gas extraction technologies over a 30-year period and then mixes the six types according to the 2009 U.S. natural gas supply profile. Three specific examples of this fundamental difference between modeling approaches are as follows:

1. A difference in method between activity-based scaling to the national level vs. well-specific production rates that scale results to each of six extraction types.
2. Differences in episodic emission factors for tight gas and the contribution of tight gas to the national inventory.
3. Time series discrepancies inherent in EPA's episodic emission factors.

Clarification on these differences is provided below.

For each type of natural gas well, NETL apportions episodic emission factors based on the production rate of a single well. These apportioned emissions are then compiled according to the relative contribution of each well type to the domestic mix to arrive at the domestic average emissions. EPA's national GHG inventory, on the other hand, does not use well production rates, but uses well activity counts for conventional and unconventional wells to scale up the episodic emission factors to a national level. It is possible that the production rates of the wells that were sampled during the development of EPA's episodic emission factors do not align with the average well production rates applied by NETL. Or the activity counts used by EPA do not align with the contribution of the six natural gas types to the national mix as modeled by NETL.

When modeling tight gas, NETL made adjustments to EPA's emission factors for well completions and workovers. A close look at EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emission factors are representative of high-pressure, tight gas wells in the San Juan and Piceance Basins that were completed using a horizontal hydraulic fracturing method and have a high, for tight gas basins, EUR of approximately 2 to 4 BCF. NETL's survey of tight gas production in the U.S. determined that an EUR of 1.2 BCF is more representative of average U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. NETL uses an emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells. It is worth noting that EPA does not distinguish between tight sands and shale gas in the annual inventory, a general category of unconventional natural gas is characterized by low and high pressure formations. NETL applied EPA's unconventional completion and workover emission factor for low pressure formations (49.57 Mcf CH_4) reported in Subpart W Technical Support Document (EPA, 2011a) to the coal bed methane well profile and the corresponding high pressure well emission factor to shale gas based on the correlation of representative EUR of 3 BCF for Barnett Shale and the San Juan and Piceance Basin EUR's representing a range of 2 to 4 BCF. While the EPA Subpart W Technical Support Document detailed the results for unconventional well completions and workovers for low pressure formations, the annual inventory (EPA, 2011a) discusses unconventional well activity as a single category assumed to be completed by hydraulic fracture, for the purposes of the inventory, and applies the high pressure formation emission factor of 9,175 Mcf CH_4 for all unconventional well completions and workovers in the annual activity count.

The differences between the top-down and comprehensive approaches is further influenced by whether or not EPA explicitly accounts for tight gas production or simply includes tight gas within its conventional onshore natural gas activity factors. Tight gas represents 31 percent of the 2009 U.S. domestic natural gas supply, and thus the results for NETL's domestic mix are sensitive to changes in the tight gas results (the extent of this sensitivity is demonstrated by the tornado chart for the domestic natural gas mix). It is not clear if EPA includes tight gas within its conventional or unconventional category. If EPA accounts for tight gas in its conventional category, then liquids unloading would be incorrectly assigned to tight gas production, which would result in an overstated result. Alternatively, if EPA accounts for tight gas in its unconventional category, then a well completion and workover emission factor based on high production tight gas formations using horizontal hydraulic fracture was applied, which would result in an overstated result. This difference is only relevant in the comparative context between the two modeling approaches (screening versus comprehensive life cycle analysis). With respect to the purpose of the EPA national inventory approach, the effects are minimized based on the granularity of the overall analysis and the comparison of results at the national sector level. As described above, NETL adjusted the episodic emission factors for tight gas and coal bed methane based on well completion method and production profile.

EPA's documentation of unconventional emission factors are provided in its Subpart W document, which is the basis for its national inventory results (EPA, 2011a). EPA's 2009 GHG inventory is representative of 2009 natural gas production; however, a close look at EPA's Subpart W document reveals that the episodic emission factors are based on relatively small samples of natural gas wells from 2006 and 2007. It is common for LCAs to use data from a broad range of years. However, the behavior of the natural gas industry was especially volatile between 2007 and 2009. The imposition of emission factors that are representative of 2006 and 2007 upon other natural gas data that are representative of anomalous activity in 2009 creates a time-series lag that introduces uncertainty to the emission factor.

Figure 4-1: Natural Gas Well Development vs. Natural Gas Production (EIA, 2011b, 2011c)

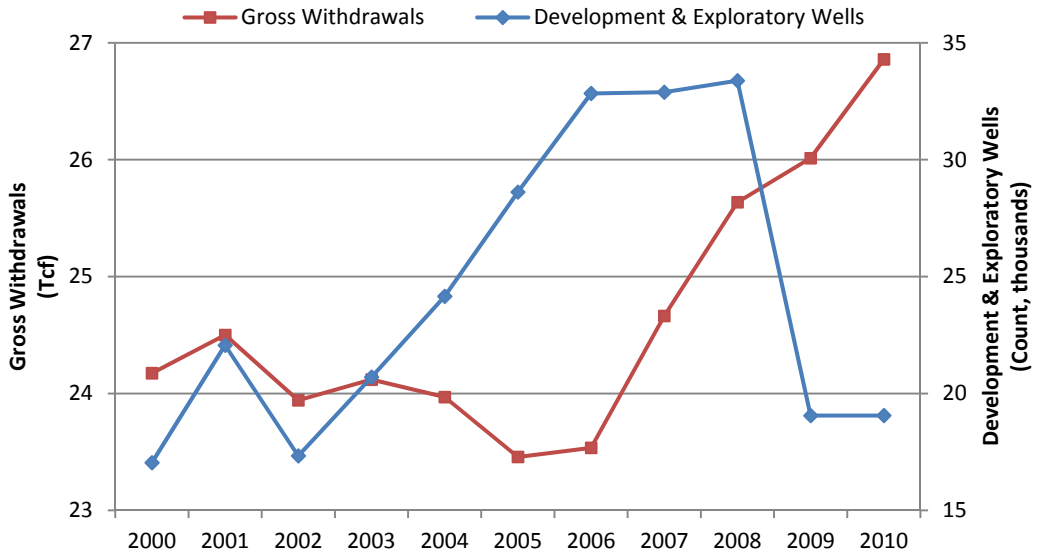


Figure 4-1 shows how increases in natural gas withdrawals lag between five and six years behind the increase in natural gas well drilling activity. Using a numerator with 2006 to 2007 data for well

activity, and 2009 data for withdrawals for the numerator could cause an undefined level of uncertainty in the emission factor. The modeling approaches used by EPA and NETL (as described in the first item above) react differently to this time-series lag. It is possible that NETL's model diminishes these effects because it amortizes the emissions over a 30-year operating period. **Table 4-1** shows the differences among key parameters of the NETL and EPA models.

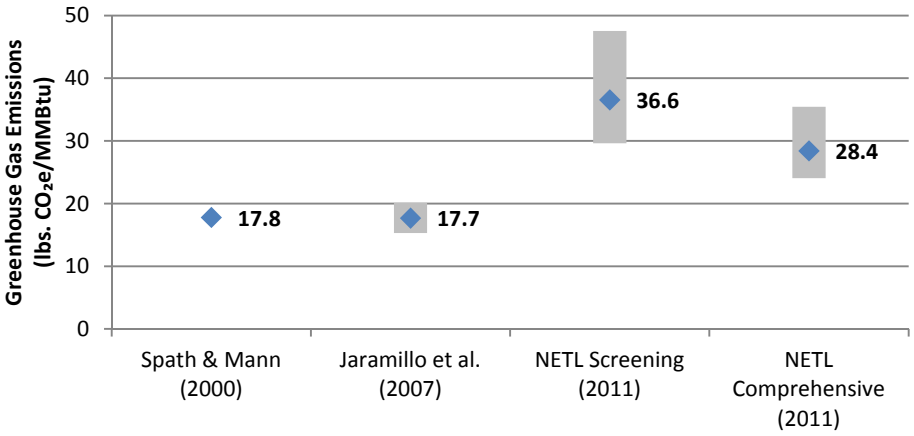
Table 4-1: Parameter Comparison between NETL and EPA Natural Gas Modeling

Property[1]	Units	NETL						EPA	
		Onshore	Assoc.	Offshore	Tight Sands[2]	Barnett Shale	CBM[3]	Conv.	Unconv.
Contribution to 2009 Mix	Percent	25%	7%	13%	31%	16%	9%	n/a	n/a
Production Rate (30-yr average)	Mcf/day	66	121	2,800	110	274	105	n/a	n/a
Active Wells (2007)	Count	n/a	n/a	n/a	n/a	n/a	n/a	431,035	41,790
Flaring Rate at Well	Percent	51%	51%	51%	15%	15%	51%	51%	15%
Completion Emissions	Mcf CH_4/episode	36.7	36.7	36.7	3,670	9,175	49.6	36.7	9,175
Workover Emissions	Mcf CH_4/episode	2.5	2.5	2.5	3,670	9,175	49.6	2.5	9,175
Workover Frequency	Episodes/year	0.04	0.04	0.04	0.12	0.12	0.12	0.04	0.12
Liquids Unloading Emissions	Mcf CH_4/episode	18.5	n/a	18.5	n/a	n/a	n/a	18.5	n/a
Liquids Unloading Frequency	Episodes/year	31	n/a	31	n/a	n/a	n/a	31	31

Figure 4-2 shows comparative greenhouse gas emissions from the three studies reviewed above. Results from each study were converted to a common basis of 100-year Global Warming Potential in pounds CO_2e per MMBtu gas delivered. The NREL study did not have an explicit range of values, so the central estimate is shown. For Jaramillo et al., the central estimate is the average of the high and low values.

[1] All emission rates are prior to flaring.
[2] The tight sands emission factor for well completions and workovers was calculated by NETL by reducing EPA's completion and workover factor (3,670 Mcf CH_4) for unconventional wells. The emission rates for completions and workovers are associated with the production rates and reservoir pressures of a well.
[3] The CBM emission factor for well completions and workovers (49.57 Mcf CH_4) is from EPA's documentation of low pressure wells. While CBM wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have lower emission rates from completions and workovers.

Figure 4-2: Comparison of Natural Gas Upstream GHGs from Other Studies



4.2 Data Limitations

A key objective of an LCA is to normalize all data to a common basis (the functional unit). Like all LCAs, this analysis is limited by data uncertainty and data limitations. Key instances of data uncertainty and limitation are summarized below.

4.2.1 Data Uncertainty

Episodic emissions, natural gas production rates, flaring rates, and pipeline distance are four areas of data uncertainty in this analysis and represented within the study results.

Episodic emission factors include the non-routine release of natural gas during well completion, workovers, and liquid unloading. The results of this analysis are sensitive to these episodic emissions. The data for episodic emissions from natural gas wells is limited to a relatively small sample of wells and includes data going back as far as 1996 (EPA, 2011a). These emission factors are not necessarily applicable to all natural gas wells. For instance, it is likely that some unconventional wells have been completed using best practices and thus have low completion emissions, while some conventional wells have been completed with poor practices and thus have high completion emissions. However, there is no basis for claiming that a more recent, larger sampling of natural gas wells would increase or decrease these emission factors.

This analysis uses the production rate for each type of natural gas well for apportioning episodic emissions to a unit of natural gas production. The production rates of unconventional natural gas wells (Barnett Shale, tight gas, and CBM wells) are based on estimated ultimate recovery (EUR) data that are specific to each formation and have specific geographical constraints (Lyle, 2011). Representativeness of unconventional production rate data provides a reasonable confidence range of +/-30 percent. Production data for conventional wells is more variable, exhibiting a 200 percent increase from the low to high production rates. This variability is due to the broad range in age, reservoir, and technology characteristics for conventional wells, making it difficult to define a "typical" conventional natural gas well.

Flaring rate is the portion of vented natural gas that is combusted; the unflared portion is released directly to the atmosphere. Conventional wells flare 51 percent of vented gas, while unconventional wells flare 15 percent of vented natural gas (EPA, 2011a). The natural gas processing plant is modeled at a 100 percent flaring rate. While technology is available to capture and flare virtually all of the vented natural gas from extraction and processing, economics and other practical concerns

often prevent the implementation of such technologies. To account for uncertainty, this analysis varied the default values for flaring rates by +/-20 percent. It is likely that there are natural gas wells that fall outside of this range; however, based on professional judgment, we expect this range to account for average natural gas production.

The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors as well as fugitive losses of natural gas. The total natural gas combustion and fugitive emissions is a function of pipeline distance, which was estimated at an average distance of 604 miles. This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the U.S. It is possible that some natural gas sources are located significantly closer to their final markets than other sources of natural gas. To account for this uncertainty, this analysis varies the average pipeline distance by +/- 20 percent, which is an uncertainty range based on professional judgment.

4.2.2 Data Availability

Most data required for this analysis were readily available. However, there are several instances for which more detailed data would enhance the functionality of the LCA model and allow further discernment among natural gas types.

- Formation-specific gas compositions (CH_4, H_2S, NMVOC, and water) for each natural gas type would allow the assignment of specific venting emissions for natural gas extraction and processing. It would also allow the calculation of the specific heat load required for natural gas processing equipment (acid gas removal and dehydration).
- The effectiveness of green completions and workovers would allow further scrutiny of the episodic emissions at wells and, possibly, further data granularity among the three unconventional well types (Barnett Shale, tight gas, and CBM wells).
- No data are available for the fugitive emissions from around wellheads (between the well casing and the ground). This is a possible emission source that could present a significant opportunity for reductions in natural gas losses at a specific wellhead or site, but is not expected to be a significant contribution from an average natural gas perspective.
- Data for water sourcing and production of other fluids used for hydraulic fracturing would expand the boundaries of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Direct and indirect GHG emissions from land use from access roads and well pads would expand the scope of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Data for the energy requirements of natural gas exploration would allow further comparisons between conventional and unconventional natural gas. Historically, conventional natural gas fields have been difficult to find, but relatively easy to develop once they are located (NGSA, 2010). In contrast, unconventional gas fields are easy to find, but require significant preparation before natural gas is recovered.

- The energy requirements for the treatment of flowback water from the hydraulic fracturing of unconventional wells would represent an environmental burden that could allow further differentiation among natural gas extraction types.
- The current EPA GHG inventory data for natural gas pipeline emissions includes methane emissions in one category. A split between venting and fugitive emissions from pipeline transport would facilitate recommendations for reducing pipeline losses. Vented emissions may present opportunities for recovery, while fugitive emissions may not represent feasible opportunities for recovery.

4.3 Recommendations for Improvement

Creating a greenhouse gas inventory from a life cycle perspective gives not only a more complete picture of the impact of the process in question, but also allows for identification for the areas of largest impact, and those with the greatest opportunity for improvement. Since this inventory is presented on two different bases, opportunities were identified in both the extraction and delivery of natural gas as well as the production of electricity from natural gas and coal.

4.3.1 Reducing the GHG Emissions of Natural Gas Extraction and Delivery

Unconventional gas sources (shale, tight sands, coal bed methane, etc.) now make up the majority of natural gas extraction. As such, the emissions released during well completion and periodic well workovers are a major contributor to the overall greenhouse gas footprint, and a large opportunity for reduction. However, due to the relatively recent development of unconventional resources, better data is needed to characterize this opportunity based on basin type, drilling method, and production in order to better identify the potential for reductions.

Transportation of processed natural gas to the point at which it is consumed – in this inventory, large end users such as power plants – makes up a large portion of the overall upstream impact. There are two components to this impact: the first is the use of energy to compress the natural gas – the initial compression to put the natural gas on the pipeline, and then periodic compression as the motive force to push the natural gas along the transmission system. The second component is fugitive emissions from joints in the pipeline and other equipment. Improving compressor efficiency not only increases the amount of sellable product, but reduces the greenhouse gases emitted delivering that product. Pipeline fugitive emissions could be reduced with both technology and best management practices.

4.3.2 Reducing the GHG Emissions of Natural Gas and Coal-fired Electricity

Although efforts to reduce methane emissions from natural gas and coal extraction and transportation are important and should be continued, most GHG emissions from their extraction, transportation and use comes in the form of post-combustion carbon dioxide. Three high-level opportunities for reducing these emissions include:

- Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir
- Improve existing power plant efficiency
- Invest in advanced power research, development, and demonstration

Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

4.4 Conclusions

This greenhouse gas (GHG) analysis inventories six different sources of natural gas, including three types of unconventional gas, combines them into a domestic mix, and then compares the inventory on both a delivered feedstock and delivered electricity basis to a similar domestic mix of coal. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy.

However, the conclusion that coal is the cleaner fuel flips once the fuels are converted to electricity in power plants with different efficiencies—53 percent for natural gas versus 35 percent for coal. Natural gas-fired electricity has a 42 percent to 53 percent lower climate impact than coal-fired electricity. Even when fired on 100 percent unconventional natural gas, from tight sands, shale and coal beds, and compared on a 20-year GWP, natural gas-fired electricity has 39 percent lower greenhouse gases than coal. This shifting conclusion based on a change in the basis of comparison highlights the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 17 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

The conclusions drawn from this inventory and the associated analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

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Appendix A:
Data and Calculations for Greenhouse Gas Inventory

Table of Contents

The energy and material flows tracked by NETL's life cycle analysis (LCA) method in support of this study are used to quantify emissions of greenhouse gases (CO_2, CH_4, and N_2O, SF_6) that would result from natural gas extraction and transport, and from coal extraction and transport. The methods for calculating these flows for the raw material acquisition (RMA) and raw material transport (RMT) of natural gas and coal are provided below.

Some common engineering conversions used in this study are:

- 1 tonne = 1,000 kg
- 1 kg = 2.205 lb
- 1 m^3 = 35.3 cf
- Natural Gas Density: 1 cf of natural gas = 0.042 lb natural gas
- Natural Gas Energy Content: 1,027 Btu/cf natural gas
- The molar ratio of CO_2 to carbon is 44/12

A.1 Raw Material Acquisition: Natural Gas

In this analysis, the boundary of the RMA for natural gas begins with the extraction of natural gas from nature and ends with processed natural gas ready for pipeline delivery. Key activities in the RMA of natural gas are as follows:

- Well construction and installation
- Natural gas sweetening (acid gas removal)
- Natural gas dehydration
- Natural gas venting and flaring
- Natural gas compression
- Well decommissioning

The data sources and assumptions for calculating the greenhouse gas (GHG) emissions from each RMA activity are provided below. In most cases, the methane emissions are calculated by using standard engineering calculations around key gas field equipment, followed by the application of the Environmental Protection Agency (EPA) AP-42 emission factors as necessary.

Well Construction and Installation

NETL's LCA model of natural gas extraction includes the construction and installation activities for natural gas wells. Construction is defined as the cradle-to-gate burdens of key materials that embody key equipment and structures. Installation is defined as the activity of preparing a site, erecting buildings or other structures, and putting equipment in place.

The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. In the case of offshore extraction, a large platform is also required. A well is lined with a carbon steel casing that is held in place with concrete. A typical casing has an inner diameter of 8.6 inches, is 0.75 inches thick, and weighs 24 pounds per foot (NaturalGas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total length of a natural gas well is variable, based on the natural gas extraction profile under consideration. The well lengths considered in this study are as follows: conventional onshore: 1,990 m; conventional offshore: 2,660 m; conventional onshore associated: 1,500 m; shale gas: 3,980 m; coal bed methane: 3,980 m; and tight gas: 2,525 m. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

The installation of natural gas wells includes the drilling of the well, followed by the installation of the well casing. Horizontal drilling is used for unconventional natural gas reserves where hydrocarbons are dispersed throughout a matrix of shale or coal. An advanced drilling rig has a drilling speed of 17.8 meters per hour, which translates to the drilling of a 7,000 foot well in approximately 10 days (NaturalGas.org, 2004). A typical diesel engine used for oil and gas exploration has a power of 700 horsepower and a heat rate of 7,000 Btu/hp-hr (EPA, 1995). The methane emissions from well installation is the product of the following three variables: heat rate of drilling engine (7,000 Btu/hp-hr), methane emission factor (EPA, 1995) for diesel combustion in stationary industrial engines (6.35E-05 lb/hp-hr), and the total drilling time (in hours).

The daily production rate of a natural gas well is an important factor in apportioning one-time construction activities or intermittent operations to a unit of natural gas production. Typical production rates vary considerably based on well type. Production rates also vary based on well specific factors, such as the age of the natural gas well. For instance, the average daily production rate for new, horizontal shale gas wells in the Barnett Shale region is as high as 2.5 million standard cubic feet (MMcf) per day, but declines at a rapid rate (Hayden & Pursell, 2005). The observed production rates in the Barnett Shale region decline 55 percent during the first year, 25 percent during the second year, 15 percent during the third year, and 10 percent each following year (Hayden & Pursell, 2005). The production rates for each type of natural gas well are shown in **Table A-12**. These production rates include the average production of natural gas wells in 2009 (the basis year of this analysis), as marginal production rates. Marginal production rates exclude poorly performing, mature wells that will likely be removed from service within a couple of years.

The construction and material requirements are apportioned to one kilogram of natural gas product by dividing them by the lifetime production of the well. The natural gas wells considered in this study are presumed to produce natural gas at the rates discussed above, with a lifetime of 30 years. Thus, construction and material requirements, and associated GHG emissions, are apportioned over the lifetime production rate specific to each type of natural gas well, based on average well production rates.

Natural Gas Sweetening (Acid Gas Removal)

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling when combusted in equipment. The removal of H_2S from natural gas is known as sweetening. Amine-based processes are the predominant technologies for the sweetening of natural gas.

The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass is modeled in this analysis. This H_2S concentration is based on raw gas composition data compiled by the Gas Processors Association (Foss, 2004).

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. Approximately 0.30 moles of H_2S are removed per 1 mole of circulated amine solution (Polasek, 2006), the reboiler duty is approximately 1,000 Btu per gallon of amine (Arnold, 1999), and the reboiler has a thermal efficiency of 92 percent. The molar mass of amine solution is assumed to be 83 g/mole, which is estimated by averaging the molar mass of monoethanolamine (61 g/mole) and diethanolamine (105 g/mole). The density of the

amine is assumed to be 8 lb/gal (3.62 kg/gal). The calculation of energy input per kilogram of natural gas product is shown in **Equation 1**.

$$\frac{0.005\ kg\ H_2S}{kg\ NG\ product} * \frac{1\ kg\ mol\ H_2S}{34\ kg\ H_2S} * \frac{1\ kg\ mol\ amine}{0.30 kg\ mol\ H_2S} * \frac{83\ kg\ amine}{kg\ mol\ amine} * \frac{1\ gal\ amine}{3.62\ kg\ amine} * \frac{1{,}000\ Btu\ reboiler\ duty}{gal\ amine} * \frac{1\ Btu\ energy\ input}{0.92\ Btu\ reboiler\ duty} = \frac{12.2\ Btu}{kg\ NG\ product} = \frac{26.9\ Btu}{lb\ NG\ product} \quad \textbf{(Equation 1)}$$

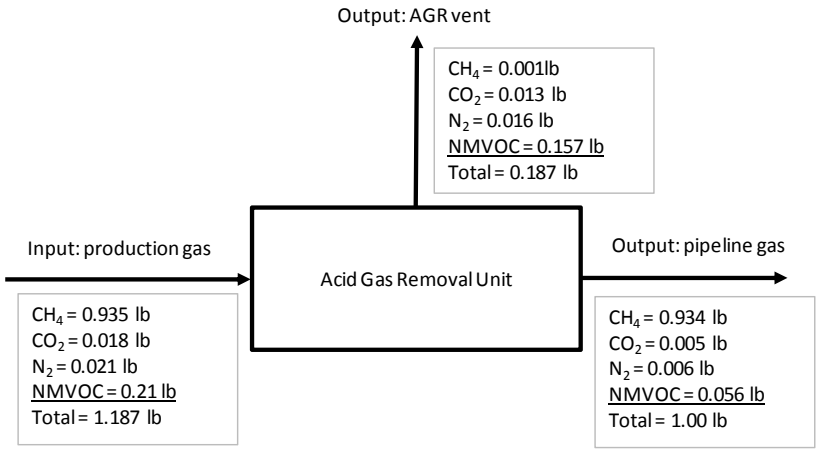
The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA, 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb per natural gas sweetened (API, 2009). The calculation of methane released by amine reboiler venting is shown in **Equation 2**.

$$\frac{0.0185\ tonne\ CH_4}{10^6\ cf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1 cf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG} \quad \textbf{(Equation 2)}$$

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. Most of this CO_2 is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. This analysis calculates the mass of naturally-occurring CO_2 emissions from the acid gas recovery (AGR) unit by balancing the composition of production gas (natural gas that has been extracted but has not undergone significant processing) and pipeline-quality gas. Production gas contains 1.52 mass percent CO_2 and pipeline-quality natural gas contains 0.47 mass percent CO_2. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas. The key constraints of this mass balance are the different compositions of input gas (production gas) and output gas (pipeline-quality gas) and the methane venting rate from amine regeneration. The mass balance around the AGR unit is illustrated by **Figure A-1.**

Figure A-1: Mass Balance for Acid Gas Removal



As shown by the mass balance around the AGR unit, the majority (84 percent by mass) of the AGR vent stream is NMVOC. At this concentration, NMVOCs are a high-value energy product. Thus, from an LCA perspective, NMVOCs are a valuable co-product of the AGR process. Co-product allocation is used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

In this analysis, the relative energy contents of the natural gas and NMVOC outputs from the AGR process are used as the basis for co-product allocation. The heating value of pipeline-quality natural gas is 24,452 Btu/lb (which is calculated from the default study value of 1,027 Btu/cf). The heating value of NMVOCs is 21,025 Btu/lb, which is calculated from the composition of the vent stream from the AGR unit and the heating values of each NMVOC component (The Engineering Toolbox, 2011); the calculation of the heating value of NMVOC is shown in **Table A-1**. As shown by the mass balance (**Figure A-1**), 0.157 lbs of NMVOC are produced for every lb of natural gas produced. When these mass flows are converted to an energy basis using the above heating values, 88.1 percent of the product leaving the AGR process is natural gas and 11.9 percent is NMVOCs. Thus, the natural gas model allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

Table A-1: Heating Value of NMVOC Co-Product from AGR Process

NMVOC Component	Percent Mass	Heating Value (Btu/lb)
CH_4	0%	23,811
Ethane	44.1%	20,525
Propane	26.7%	21,564
Iso-Butane	5.9%	21,640
n-Butane	10.4%	21,640
iso-Pentane	3.0%	20,908
n-Pentane	3.9%	20,908
Hexanes	3.0%	20,526
Heptanes Plus	2.9%	21,000
Other (N_2 and CO_2)	0%	0
Composite Heating Value		21,025

The following table shows the energy consumption and GHG emissions for acid gas removal. These energy and emission factors do not account for the co-product allocation between natural gas and NMVOCs. The co-product allocation between natural gas and NMVOC is performed within the modeling software (GaBi).

For **Table A-2**, the energy used for acid gas removal is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent. The CH_4 venting factor assumes that the reboiler vent is not flared.

Table A-2: Acid Gas Removal (Sweetening)

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	26.9	Btu/lb NG product	calculated
Reboiler fuel	2.26E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2 (combustion)	6.47E-04	lb CO_2/lb NG product	calculated
CO_2 (vented)	0.013	lb CO_2/lb NG product	calculated
N_2O	3.54E-06	lb N_2O/lb NG product	calculated
CH_4 (combustion)	1.27E-05	lb CH_4/lb NG product	calculated
CH_4 (vented)	9.71E-04	lb CH_4/lb NG product	API 2009
NMVOC (vented)	0.157	lb NMVOC/lb NG product	calculated

Natural Gas Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

The fuel requirements of dehydration are a function of the reboiler duty. Due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMcf. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 152,000 Btu/MMcf of dehydrated natural gas (as shown by **Equation 3** and **Equation 4** below). Assuming that the reboiler is fueled by natural gas, this translates to 1.48E-04 lb of natural gas combusted per lb of dehydrated natural gas (as shown by the equations below). The emission factor for the combustion of natural gas in boiler equipment produces 2.3 lb CH_4/million cf natural gas (API, 2009). After converting to common units, the above fuel consumption rate and methane emission factor translate to 8.09E-09 lb CH_4/lb NG treated.

$$\frac{3.00\ gal\ glycol}{lb\ water} * \frac{1{,}124\ Btu}{gal\ glycol} * \frac{(49-4)\ lb\ water}{MMCF\ NG} = \frac{152{,}000\ Btu}{MMcf\ NG} \qquad \textbf{(Equation 3)}$$

$$\frac{152{,}000\ Btu}{MMcf\ NG} * \frac{MMcf\ NG}{10^6 cf\ NG} * \frac{1\ cf\ NG}{1027\ Btu} = \frac{1.48\times10^{-4}\ lb\ NG\ fuel}{lb\ NG\ product} \quad \textbf{(Equation 4)}$$

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators are used to capture most of methane emissions from glycol strippers; nonetheless, small amounts of methane are vented from dehydrators. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 8.06E-06 lb of methane is released for every pound of natural gas that is dehydrated.

For **Table A-3**, the energy used for dehydration is based on 3 gallons of glycol per pound of water removed, a reboiler duty of 1,124 Btu per gallon of glycol regenerated, and 45 pounds of water removed per MMcf of natural gas produced. The methane venting factor assumes that no flash separator is used to control venting emissions.

Table A-3: Natural Gas Dehydration

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	1.52E-01	Btu/cf NG product	API 2009
Reboiler fuel	1.48E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2	4.24E-04	lb CO_2/lb NG product	calculated
N_2O	2.26E-09	lb N_2O/lb NG product	calculated
CH_4 (combustion)	8.10E-09	lb CH_4/lb NG product	calculated
CH_4 (venting)	8.06E-06	lb CH_4/lb NG product	API 2009

Natural Gas Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. The flaring emission factors published by the American Petroleum Institute (API, 2009) are based on the following recommendations by the Intergovernmental Panel on Climate Change (IPCC):

- If measured data are not available, assume flaring has a 98 percent destruction efficiency. Destruction efficiency is a measure of how much carbon in the flared gas is converted to CO_2 (API, 2009).
- The CO_2 emissions from flaring are the product the destruction efficiency, carbon content of the flared gas, the molar ratio of CO_2 to carbon (44/12). Methane is 75 percent carbon by mass, and the other hydrocarbons in natural gas are approximately 81 percent carbon by mass

(Foss, 2004); the composite carbon content of natural gas is calculated by factoring these carbon compositions with the natural gas composition.

- Methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2 (API, 2009).
- N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.8 percent CH_4, 1.5 percent CO_2, 1.78 percent nitrogen, and 17.9 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). The mass composition of pipeline quality natural gas is 93.4 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.6 percent NMVOCs. The composition of production natural gas to model flaring during natural gas extraction, and the composition of pipeline quality natural gas is used to model flaring at the natural gas processing plant. The above method for estimating flaring emissions was applied to these gas compositions to develop flaring emission factors for production and pipeline natural gas. The following table summarizes the mass composition and flaring emissions for these two gas compositions.

Table A-4: Natural Gas Flaring

Emission	Production NG	Pipeline NG	Units	Reference
Natural Gas Composition				
CH_4	78.8%	93.4%	% mass	(EPA, 2011a)
CO_2	1.52%	0.47%	% mass	(EPA, 2011a)
Nitrogen	1.78%	0.55%	% mass	(EPA, 2011a)
NMVOC	17.90%	5.57%	% mass	(EPA, 2011a)
Flaring Emissions				
CO_2	2.67	2.69	lb CO_2/lb flared NG	API, 2009
N_2O	8.95E-05	2.79E-05	lb N_2O/lb flared NG	API, 2009
CH_4	1.53E-02	1.81E-02	lb CH_4/lb flared NG	API, 2009

The venting rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Venting rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, venting rates have been parameterized in the model to allow uncertainty analysis.

Recent data indicate that only 51 percent of vented natural gas from conventional natural gas extraction operations is flared and the remaining 49 percent is released to the atmosphere (EPA, 2011a). The flaring rate is even lower for unconventional wells, which flare 15 percent of vented natural gas (EPA, 2011a). The flaring rate at natural gas processing plants is assumed to be 100 percent.

Venting from Well Completion

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a). Barnett Shale and tight gas wells are high pressure wells, and thus have higher completion venting than coal bed methane and conventional wells (EPA, 2011a).

When modeling tight gas, adjustments were made to EPA's emission factors for well completions and workovers. EPA's documentation (EPA, 2011a) indicates that its unconventional completion

and workover emissions are representative of high-pressure, tight gas wells in the San Juan and Piceance basins, which are horizontal wells that were completed using hydraulic fracturing and have an estimated ultimate recovery of 3 Bcf. A survey of tight gas production in the U.S. determined that an estimated ultimate recovery of 1.2 Bcf is more representative of U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. An emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells is used.

Tight gas emissions are not the only emission factor adjusted for the model. While coal bed methane (CBM) wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have relatively low emission rates from completions and workovers. The CBM emission factor used for the completion and workover of CBM wells is 49.57 Mcf CH_4 (EPA, 2011a). This is much lower than the completion and workover emission factor that EPA recommends for unconventional wells (9,175 Mcf CH_4).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) the methane emissions from conventional well completions are 1,538 lb/completion (698 kg/completion). For unconventional wells the venting rates are 386,000 lb/completion (175,000 kg/completion) for Barnett Shale, 2,090 lb/completion (946 kg/completion) for coal bed methane, and 154,000 lb/completion (70,064 kg/completion) for tight gas (EPA, 2011a).

Venting from Well Workovers

The methane emissions from the workover of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 2.454 Mcf/workover and unconventional wells produce 9,175 Mcf/workover. (Note that the workover emission factor for unconventional wells is the same as the completion emission factor for unconventional wells.) This analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) and the conversion factor of 2.205 lb/kg, the methane emissions from well workovers are 103 lb/workover (46.7 kg/workover) for conventional wells. The workover venting rates for unconventional wells are assumed to be equal to their completion venting rates (EPA, 2011a).

Unlike well completions, well workovers occur more than one time during the life of a well. The frequency of well workovers was calculated using EPA's accounting of the total number of natural gas wells in the U.S. and the total number of workovers performed per year (all data representative of 2007). For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

Venting from Liquid Unloading

Liquid unloading is necessary for conventional gas wells. It is not necessary for unconventional wells or associated gas wells.

The methane emissions from the unloading of liquid from conventional wells are based on emission factors developed by EPA. In 2007, conventional wells produced 223 Bcf/year (EPA, 2011a), which is 4.25 million metric tons per year using a natural gas density of 0.042 lb/cf. There were

approximately 389,000 unconventional wells in 2007. When the annual emissions are divided by the total number of wells, the resulting emission factor is 10.9 metric tons per well-year.

Liquid unloading is a routine operation for conventional gas wells. The frequency of liquid unloading was calculated using EPA's assessment of two producers and the unloading activities for their wells (EPA, 2011a). From this sampling, EPA calculated that there are 31 liquid unloading episodes per well-year (EPA, 2011a).

When the emission factor for liquid unloading is divided by the average number of unloading episodes, the resulting methane emission factor is 776 lb/episode (352 kg/episode).

Venting from Wet Seal Degassing

The emission factor for wet seal degassing accounts for the natural gas lost during the regeneration of wet seal oil, which is used for centrifugal compressors. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010). According to EPA's sampling of these platforms, the emissions from wet seal oil degassing are 33.7 million m^3 of methane annually. These platforms produce 4.88 billion m^3 of natural gas annually. When the emission rate for this category is divided by the production rate, the resulting emission factor is 0.00690 m^3 of vented gas per m^3 of produced gas. Assuming the emissions have the same density as the produced gas, this emission factor is 0.00690 lb of natural gas/lb produced natural gas.

Fugitive Emissions from Pneumatic Devices

The extraction and processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction or processing site. Thus, this analysis assumes that the operation of pneumatic systems result in the emission of fugitive natural gas emissions.

Data for the fugitive emissions from pneumatic devices are based on EPA data for offshore wells, onshore wells, and gas processing plants (EPA, 2011a). EPA’s data is based on 2006 production (EPA, 2011a) and shows the methane emissions for specific wellhead and processing activities. This analysis translated EPA’s data to a basis of lb methane per lb of natural gas production by dividing the methane emission rate by the natural gas production rate. For example, the annual emissions from pneumatic devices used for offshore production are 7 MMcf of methane; when divided by the annual offshore production rate of 3,584,190 MMcf, this translates to an emission factor of 1.95E-06 lb of methane per lb of natural gas produced (this calculation assumes that the volumetric densities of methane and natural gas are the same). The fugitive emissions from pneumatic devices used by offshore wells, onshore wells, and natural gas processing plants are shown in the following table.

Table A-5: Fugitive Emissions from Pneumatic Devices

Location	MMcf/yr (EPA, 2011a)		Emission Factor
	CH_4 emission	NG Production	lb CH_4/lb NG
Onshore	52,421	19,950,828	2.63E-03
Offshore	7.0	3,584,190	1.95E-06
Processing	93	14,682,188	6.33E-06

Other Point Source and Fugitive Emissions

The emissions described above account for natural gas emissions from specific processes, including the episodic releases of natural gas during well completion, workovers, and liquid unloading, as well as routine releases from wet seal degassing, AGR, and dehydration. Natural gas is also released by other extraction and processing equipment. To account for these other emissions, NETL's model includes two additional emission categories: other point source emissions and other fugitive emissions. Other point source emissions account for natural gas emissions that are not accounted for elsewhere in model and can be recovered for flaring. Other fugitive emissions include emissions that are not accounted for elsewhere in the model and cannot be recovered for flaring.

EPA's Background Technical Support Document - Petroleum and Natural Gas Industry (EPA, 2011a) was used for quantifying the other point source and fugitive emissions from natural gas extraction and processing. A three-step process was used to filter EPA's venting and flaring data so that it is consistent with the boundary assumptions of this analysis:

1. Emissions that are accounted for by NETL's existing natural gas unit processes were not included in the categories for other point source and fugitive emissions. For example, EPA provides emission rates for well construction, well completion, dehydration, and pneumatic devices. The emissions from these activities are accounted for elsewhere in NETL's model and thus, to avoid double counting, are not included in the emission factors for other point and fugitive emissions.
2. Emissions that fall within NETL's boundary definitions for natural gas processing were moved from the natural gas extraction category to the natural gas processing category.
3. The EPA data (EPA, 2011a) does not discern between point source and fugitive emissions, so emissions were assigned to the point source or fugitive emission categories based on another EPA reference that provides more details on point source and fugitive emissions (Bylin, et al., 2010).

Other Point Source and Fugitive Emissions from Onshore Extraction

The data for other point source and fugitive emissions from onshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from construction, dehydration, compressors, well completion, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Additionally, emissions from Kimray pumps, condensate tanks, and compressor blowdowns are re-categorized as natural gas *processing* emissions in NETL's model, and are thus not included in the emission factors for natural gas *extraction*. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from onshore gas extraction are 7.49E-05 lb CH_4/lb NG extracted and 1.02E-03 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-6**.

Table A-6: Other Point Source and Fugitive Emissions from Onshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Gas Wells	2,751	Construction		
Heaters	1,463		1,463	
Separators	4,718			4,718
Dehydrators	1,297	Dehydrator		
Meters/Piping	4,556			4,556
Small Reciprocating Compressor	2,926	Reciprocating Compressor		
Large Reciprocating Compressor	664	Reciprocating Compressor		
Large Reciprocating Stations	45	Reciprocating Compressor		
Pipeline Leaks	8,087			8,087
Vented and Combusted				
Completion Flaring	0	Well Completion V&F		
Well Drilling	96	Well Completion		
Coal Bed Methane	3,467	Well Completion		
Pneumatic Device Vents	52,421	Pneumatic Devices		
Chemical Injection Pumps	2,814			2,814
Kimray Pumps	11,572	In NG processing boundary		
Dehydrator Vents	3,608	Dehydrator V&F		
Condensate Tanks without Control Devices	1,225	In NG processing boundary		
Condensate Tanks with Control Devices	245	In NG processing boundary		
Gas Engines, Compressor Exhaust Vented	11,680	Gas Compressor		
Well Workovers				
Well Workovers, Gas Wells	47	Well Workovers		
Well Workovers, Well Clean Ups (Low Pressure Gas Wells)	9,008	Well Workovers		
Blowdowns				
Blowdowns, Vessel	31		31	
Blowdowns, Pipeline	129			129
Blowdowns, Compressors	113	In NG processing boundary		
Blowdowns, Compressor Starts	253	In NG processing boundary		
Upsets				
Pressure Relief Valves	29			29
Mishaps	70			70
Total Emissions	123,315		1,494	20,403
Total NG Extracted	19,950,828			
Emission Rate (lb CH_4/lb NG extracted)			**7.49E-05**	**1.02E-03**

Other Venting and Fugitive Emissions from Offshore Extraction

The data for other point source and fugitive emissions from offshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from drilling rigs, flares, centrifugal seals, glycol dehydrators, gas engines and turbines, and pneumatic pumps; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from offshore gas extraction are 3.90E-05 lb CH_4/lb NG extracted and 2.41E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-7.**

Table A-7: Other Point Source and Fugitive Emissions from Offshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Amine gas sweetening unit	0.2	AGR and CO_2 removal		
Boiler/heater/burner	0.8		0.80	
Diesel or gasoline engine	0.01		0.01	
Drilling Rig	3	Construction		
Flare	24	Venting and Flaring		
Centrifugal Seals	358	Centrifugal Compressor		
Connectors	0.8			0.80
Flanges	2.4			2.38
Open Ended Line	0.1			0.10
Other	44			44.0
Pump Fugitive	0.5			0.50
Valves	19			19.00
Glycol Dehydrator	25	Dehydrator		
Loading Operation	0.1			0.10
Separator	796			796
Mud Degassing	8.0		8.00	
Natural Gas Engines	191	Reciprocating compressor		
Natural Gas Turbines	3.0	Centrifugal compressor		
Pneumatic Pumps	7.0	Pneumatic Devices		
Pressure Level Controls	2.0			2.00
Storage Tanks	7.0		7.00	
Variable Exhaust Nozzle Exhaust Gas	124		124	
Total Emissions	1616		140	865
Total Processed NG	3,584,190			
Emission Rate (lb CH_4/lb NG extracted)			**3.90E-05**	**2.41E-04**

Other Venting and Fugitive Emissions from Natural Gas Processing

The data for other point source and fugitive emissions from natural gas processing are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from reciprocating compressors, centrifugal compressors, AGR units, dehydrators, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from natural gas processing are 3.68E-04 lb CH_4/lb NG extracted and 8.25E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-8**.

Table A-8: Other Point Source and Fugitive Emissions from NG Processing

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Plants	1,634		3,104	
Recip Compressors	17,351	Reciprocating Compressor		
Centrifugal Compressors	5,837	Centrifugal Compressor		
Vented and Combusted (Normal Operations)				
Compressor Exhaust, Gas Engines	6,913	Reciprocating Compressor		
Compressor Exhaust, Gas Turbines	195	Centrifugal Compressor		
AGR Vents	643	AGR and CO_2 removal		
Kimray Pumps (Glycol Pump for Dehydrator)	177			11,749
Dehydrator Vents	1,088	Dehydrator venting & flaring		
Pneumatic Devices	93	Pneumatic Device		
Routine Maintenance				
Blowdowns/Venting	2,299		2,299	366
Total Emissions	36,230		5,403	12,115
Total Production	14,682,188			
Emissions Rate (lb CH_4/lb NG processed)			**3.68E-04**	**8.25E-04**

Natural Gas Compression

Compressors are used to increase the gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. The inlet pressure depends on the pressure of the natural gas reservoir and pressure drop during gas processing and thus introduces uncertainty to the model. The outlet pressure of 800 psig is a standard pressure for pipeline transport of natural gas.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas. This energy rate represents the required *output* of the compressor shaft; the *input* fuel requirements for compression vary according to compression technology. The two types of compressors used for natural gas operations are reciprocating compressors and centrifugal compressors. These two compressor types are discussed below.

Reciprocating compressors account for an estimated 75 percent of wellhead compression in the Barnett Shale gas play, and are estimated to accounted for all wellhead compression at conventional onshore, conventional onshore associated, and coal bed methane wells. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/cf (API, 2009), a natural gas density of 0.042 lb/cf (API, 2009), and converting to kilograms translates to 217 kg of natural gas per MWh of centrifugal, gas-powered turbine output. This fuel factor represents the mass of natural gas that is

combusted per compressor energy output. The carbon dioxide emissions from a gas-powered, 4-stroke reciprocating compressor are 110 lb/MMBtu of fuel input. Similarly, the methane emissions from the same type of reciprocating compressor are 1.25 lb/MMBtu of fuel input (EPA, 1995); these methane emissions result from leaks in compressor rod packing systems and are based on measurements conducted by the EPA on a sample of 22 compressors (EPA, 1995).

The emissions for the operation of wellhead compressors are shown in **Table A-9** below.

Table A-9: Gas-Powered Reciprocating Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	1.25 lb/MMBtu fuel	5.37E-04 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	478 lb NG/MWh	217 kg NG/MWh	HARC 2006
Fuel input	3.54E-02 lb NG/lb NG	3.54E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.095 lb/lb NG	0.095 kg/kg NG	calculated
CH_4	1.08E-03 lb/lb NG	1.08E-03 kg/kg NG	calculated

Gas powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage centrifugal compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas.

Table A-10: Gas-Powered Centrifugal Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	8.60E-03 lb/MMBtu fuel	3.70E-06 kg/MJ fuel	EPA 1995
N_2O	3.00E-03 lb/MMBtu fuel	1.29E-06 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	443 lb NG/MWh	201 kg NG/MWh	API 2009
Fuel input	3.28E-02 lb NG/lb NG	3.28E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.088 lb/lb NG	0.088 kg/kg NG	calculated
CH_4	6.89E-06 lb/lb NG	6.89E-06 kg/kg NG	calculated
N_2O	2.40E-06 lb/lb NG	2.40E-06 kg/kg NG	calculated

Electrically-powered centrifugal compressors account for an estimated 25 percent of wellhead compression in the Barnett Shale gas play, but were not found to be utilized in substantial numbers outside of the Barnett Shale. If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city.

An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the Electric Reliability Council of Texas (ERCOT) grid, which is representative of electricity generation in Texas (the location of Barnett Shale). The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation. Electric compressors have negligible methane emissions because they do not require a fuel line for the combustion of product natural gas and incomplete combustion of natural gas is not an issue (EPA, 2011c). Electric compressors are also recommended by EPA's Natural Gas STAR program as a strategy for reducing system emissions of methane (EPA, 2011c).

Table A-11: Electrically-Powered Centrifugal Compressor Operations

Air Emissions from Electricity Generation			
CO_2	1,784 lb/MWh	809 kg/MWh	calculated
N_2O	2.29E-02 lb/MWh	1.04E-02 kg/MWh	calculated
CH_4	2.36 lb/MWh	1.07 kg/MWh	calculated
SF_6	2.23E-09 lb/MWh	1.01E-09 kg/MWh	calculated
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb NG	1.63E-04 MWh/kg	GE 2005
Heat rate	1.053 MWh/MWh	1.053 MWh/MWh	API 2009
Electricity input	7.80E-05 MWh/lb NG	1.72E-04 MWh/kg NG	calculated
Air Emissions			
CO_2	0.139 lb/lb NG	0.139 kg/kg NG	calculated
N_2O	1.78E-06 lb/lb NG	1.78E-06 kg/kg NG	calculated
CH_4	1.84E-04 lb/lb NG	1.84E-04 kg/kg NG	calculated
SF_6	1.73E-13 lb/lb NG	1.73E-13 kg/kg NG	calculated

Well Decommissioning

This analysis assumes that the de-installation of a natural gas well incurs ten percent of the energy requirements and emissions as the original installation of the well.

Compilation of Natural Gas Processes

All energy and emissions data for the extraction of natural gas are described above. The compilation of these data into a model for natural gas extraction involves the connection of all unit processes into an interdependent network.

To model the extraction of natural gas from different sources (onshore, offshore, unconventional, etc.) it is necessary to tune each unit process within this network with a set of source-specific parameters. The assumptions used to adjust the unit processes into profiles of specific natural gas types are shown in **Table A-12**.

Table A-12: Natural Gas Modeling Parameters

Property	Units	Onshore	Associated	Offshore	Tight Sands	Barnett Shale	Coal Bed Methane
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
2009 Production Rate	Mcf/day	65.6	121	2,795	110	273	104
Marginal Production Rate	Mcf/day	592	398	6,165	110	273	76.2
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	Mcf/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	Mcf/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	Mcf/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.043	0.043	0.01	0.043	0.043	0.043
Natural Gas Processing Plant							
AGR and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%	100%	100%	100%	100%	100%
Methane Absorbed into Amine Solution	lb CH_4/Mcf	0.04	0.04	0.04	0.04	0.04	0.04
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/Mcf	0.56	0.56	0.56	0.56	0.56	0.56
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/Mcf	0.21	0.21	0.21	0.21	0.21	0.21
NMVOC Absorbed into Amine Solution	lb NMVOC/Mcf	6.59	6.59	6.59	6.59	6.59	6.59
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%	100%	100%	100%	100%	100%
Water Removed by Dehydrator Unit	lb H_2O/Mcf	0.045	0.045	0.045	0.045	0.045	0.045
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/Mcf	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Pneumatic Devices and Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%	100%	100%	100%	100%	100%
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.05	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.02	0.02	0.02	0.02	0.02	0.02
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.03	0.03	0.03	0.03	0.03	0.03
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Production Rates for Conventional Onshore Natural Gas Wells

The purpose of this discussion is to describe the data sources and calculations used to determine the typical production rate of conventional onshore natural gas wells. The population of conventional onshore wells is a lot more diverse that other types of natural gas wells, and thus it is necessary to distinguish between the large population of wells with low production rates and the relatively small population of wells with high production rates.

The Energy Information Administration (EIA) collects production data for oil and gas wells in the U.S. and organizes it according to production rates. The EIA data for total U.S. production is shown in **Table A-13**. The data in **Table A-13** are copied directly from EIA (EIA, 2010b) and show 22 production rate brackets. The lowest bracket includes wells that produce less than one barrel of oil equivalent (BOE) per day, and the highest bracket represents wells that produce more than 12,800 BOE per day. The EIA data have separate groups for oil wells and gas wells; from these data, we know that in 2009 the U.S. had 363,459 oil wells and 461,388 gas wells. These data also show the co-production of oil at gas wells as well as the average per well production rate within each production rate bracket.

The goal of this discussion is to focus on conventional onshore gas extraction. The data in **Table A-13** includes offshore production, and to develop a more accurate representation of onshore gas production, it is necessary to remove offshore data from the total U.S. profile. The EIA also has data for offshore production, as shown by **Table A-14**. By subtracting the offshore data from the total U.S. well profile, production data exclusive to onshore wells can be determined, as shown in **Table A-15**.

Table A-13: U.S. Total 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010b)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (MMbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (Bcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/Day)
0-1	127,734	35.1	15.4	0.9	0.4	4.8	0.1	91,005	19.7	73.4	0.3	2.4	0.7	0.0
1-2	45,649	12.6	21.8	1.3	1.4	9.5	0.6	45,034	9.8	131.1	0.5	8.3	1.3	0.1
2-4	47,803	13.2	45.3	2.8	2.7	22.3	1.3	60,930	13.2	358.3	1.5	16.6	3.6	0.2
4-6	27,625	7.6	43.6	2.7	4.4	29.4	3.0	43,009	9.3	428.4	1.8	28.0	4.4	0.3
6-8	21,816	6.0	48.3	2.9	6.2	36.7	4.7	32,564	7.1	457.8	1.9	39.4	4.5	0.4
8-10	15,482	4.3	42.9	2.6	7.7	40.0	7.2	24,829	5.4	451.1	1.9	50.8	4.3	0.5
10-12	12,642	3.5	43.8	2.7	9.7	33.5	7.4	18,967	4.1	420.5	1.8	62.1	4.1	0.6
12-15	11,801	3.2	50.3	3.1	11.9	37.3	8.8	21,718	4.7	591.1	2.5	76.2	5.7	0.7
15-20	13,895	3.8	75.1	4.6	15.2	60.8	12.3	23,974	5.2	841.3	3.5	98.5	7.7	0.9
20-25	8,157	2.2	56.6	3.4	19.6	46.2	16.1	16,539	3.6	744.2	3.1	126.5	7.5	1.3
25-30	6,276	1.7	52.3	3.2	23.7	46.5	21.1	11,638	2.5	644.9	2.7	156.7	5.1	1.2
30-40	7,207	2.0	75.3	4.6	30.0	69.0	27.5	16,083	3.5	1,122.3	4.7	197.4	9.5	1.7
40-50	3,684	1.0	49.0	3.0	39.1	42.1	33.5	9,959	2.2	895.6	3.7	255.6	7.1	2.0
50-100	7,934	2.2	159.7	9.7	59.4	171.4	63.7	22,546	4.9	3,156.6	13.2	402.7	22.4	2.9
100-200	3,070	0.8	119.1	7.3	118.3	115.9	115.1	13,444	2.9	3,520.4	14.7	782.4	30.8	6.8
200-400	1,469	0.4	109.9	6.7	233.9	122.3	260.3	5,528	1.2	2,572.2	10.7	1,545.1	22.3	13.4
400-800	663	0.2	92.3	5.6	447.9	128.5	623.6	2,038	0.4	1,708.3	7.1	3,007.9	22.2	39.0
800-1,600	264	0.1	77.8	4.7	900.8	114.4	1,325.0	816	0.2	1,342.4	5.6	6,039.3	25.0	112.6
1,600-3,200	145	0.0	86.8	5.3	1,770.4	121.8	2,485.6	460	0.1	1,633.2	6.8	11,907.5	35.8	261.0
3,200-6,400	66	0.0	88.1	5.4	3,950.0	92.9	4,167.6	247	0.1	1,913.3	8.0	22,917.6	46.1	552.0
6,400-12,800	47	0.0	112.4	6.8	7,428.9	132.1	8,729.2	51	0.0	725.3	3.0	46,468.5	9.9	635.0
> 12,800	30	0.0	176.5	10.7	18,162.2	136.8	14,083.1	9	0.0	227.5	0.9	84,081.9	3.3	1,204.3
Total	**363,459**	**100.0**	**1,642.3**	**100.0**	**12.9**	**1,614.4**	**12.7**	**461,388**	**100.0**	**23,959.1**	**100.0**	**148.5**	**283.2**	**1.8**

Table A-14: Federal Gulf 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010a)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0-1	46	1.5	3.1	0.0	0.3	4.8	0.4	116	4.4	52.2	0.0	1.9	0.7	0.0
1-2	23	0.8	6.5	0.0	1.2	10.2	1.9	55	2.1	112.1	0.0	8.2	1.7	0.1
2-4	40	1.3	30.4	0.0	2.5	43.0	3.5	70	2.7	278.2	0.0	15.8	4.2	0.2
4-6	37	1.2	41.6	0.0	4.0	71.0	6.8	74	2.8	538.6	0.0	27.4	8.1	0.4
6-8	43	1.4	66.9	0.0	5.4	108.4	8.8	51	1.9	499.7	0.0	37.8	8.2	0.6
8-10	46	1.5	101.6	0.0	7.0	169.0	11.7	43	1.6	609.0	0.0	50.0	6.4	0.5
10-12	32	1.1	89.2	0.0	9.2	111.5	11.5	35	1.3	547.3	0.0	56.6	14.5	1.5
12-15	65	2.2	229.0	0.0	11.3	267.8	13.2	51	1.9	1,041.6	0.1	69.9	28.1	1.9
15-20	99	3.3	448.9	0.1	14.1	676.8	21.2	89	3.4	2,557.3	0.1	93.8	43.2	1.6
20-25	101	3.4	625.5	0.1	18.6	792.3	23.5	84	3.2	3,023.3	0.2	121.1	56.3	2.3
25-30	111	3.7	856.6	0.2	23.1	937.8	25.3	77	2.9	3,140.6	0.2	146.8	59.5	2.8
30-40	216	7.2	2,107.2	0.4	28.5	2,821.7	38.2	126	4.8	7,456.0	0.4	191.8	109.5	2.8
40-50	189	6.3	2,403.6	0.4	37.1	2,952.2	45.6	108	4.1	7,788.0	0.4	240.3	175.6	5.4
50-100	638	21.3	13,471.4	2.5	60.5	16,722.2	75.1	351	13.3	42,876.5	2.3	394.8	718.7	6.6
100-200	506	16.9	21,060.9	3.9	118.8	23,817.1	134.4	388	14.7	99,838.2	5.3	815.0	1,272.4	10.4
200-400	303	10.1	23,902.4	4.4	234.2	27,232.1	266.9	357	13.5	171,637.2	9.1	1,587.1	2,113.7	19.5
400-800	157	5.2	24,319.8	4.5	465.6	28,928.2	553.8	281	10.6	267,687.1	14.2	3,139.7	3,352.2	39.3
800-1,600	124	4.1	37,018.6	6.8	911.9	51,361.6	1,265.2	155	5.9	297,842.7	15.8	6,179.4	5,209.8	108.1
1,600-3,200	86	2.9	53,804.6	9.9	1,901.4	73,151.5	2,585.1	72	2.7	281,825.9	15.0	12,283.7	5,179.9	225.8
3,200-6,400	58	1.9	79,016.7	14.5	4,001.7	81,878.3	4,146.6	34	1.3	259,606.8	13.8	24,584.0	4,941.2	467.9
6,400-12,800	45	1.5	107,626.0	19.8	7,472.5	126,500.1	8,782.9	16	0.6	234,073.5	12.4	53,797.6	909.8	209.1
> 12,800	30	1.0	176,482.4	32.5	18,162.2	136,845.3	14,083.1	8	0.3	200,795.6	10.7	85,773.4	2,324.5	992.9
Total	**2,995**	**100.0**	**543,712.9**	**100.0**	**541.3**	**575,403.0**	**572.8**	**2,641**	**100.0**	**1,883,827.2**	**100.0**	**2,396.7**	**26,538.1**	**33.8**

Table A-15: U.S. 2009 Distribution of Onshore Gas Wells (EIA, 2010a, 2010b)

Prod. Rate Bracket (BOE/day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/day)	Gas Energy Equivalent (MMBtu/day)	Oil Energy Equivalent (MMBtu/day)	% of Energy from Gas	Adjusted Gas Rate per Well, (Mcf/Day)[1]
0-1	90,889	19.8%	73.4	0.3%	2.2	0.7	0.0	2.3	0.1	94.9%	2.3
1-2	44,979	9.8%	131.0	0.6%	8.0	1.3	0.1	8.2	0.5	94.7%	8.4
2-4	60,860	13.3%	358.0	1.6%	16.1	3.6	0.2	16.6	0.9	94.6%	17.0
4-6	42,935	9.4%	427.9	1.9%	27.3	4.4	0.3	28.0	1.6	94.5%	29.0
6-8	32,513	7.1%	457.3	2.1%	38.5	4.5	0.4	39.6	2.2	94.7%	41.0
8-10	24,786	5.4%	450.5	2.0%	49.8	4.3	0.5	51.1	2.8	94.9%	52.0
10-12	18,932	4.1%	420.0	1.9%	60.8	4.1	0.6	62.4	3.4	94.8%	64.0
12-15	21,667	4.7%	590.1	2.7%	74.6	5.7	0.7	76.6	4.2	94.9%	79.0
15-20	23,885	5.2%	838.7	3.8%	96.2	7.7	0.9	98.8	5.1	95.1%	101.0
20-25	16,455	3.6%	741.2	3.4%	123.0	7.4	1.2	127.0	7.0	94.6%	130.0
25-30	11,561	2.5%	641.8	2.9%	152.0	5.0	1.2	156.0	7.0	95.8%	159.0
30-40	15,957	3.5%	1,114.8	5.1%	191.0	9.4	1.6	197.0	9.0	95.5%	201.0
40-50	9,851	2.1%	887.8	4.0%	247.0	6.9	1.9	254.0	11.0	95.8%	258.0
50-100	22,195	4.8%	3,113.7	14.1%	384.0	21.7	2.7	395.0	16.0	96.2%	399.0
100-200	13,056	2.8%	3,420.6	15.5%	718.0	29.5	6.2	737.0	36.0	95.4%	753.0
200-400	5,171	1.1%	2,400.6	10.9%	1,272.0	20.2	10.7	1,306.0	62.0	95.5%	1,332.0
400-800	1,757	0.4%	1,440.6	6.5%	2,246.0	18.9	29.4	2,307.0	170.0	93.1%	2,412.0
800-1,600	661	0.1%	1,044.6	4.7%	4,330.0	19.8	82.0	4,446.0	476.0	90.3%	4,793.0
1,600-3,200	388	0.1%	1,351.4	6.1%	9,542.0	30.6	216.0	9,800.0	1,254.0	88.7%	10,763.0
3,200-6,400	213	0.0%	1,653.7	7.5%	21,271.0	41.2	529.0	21,845.0	3,071.0	87.7%	24,261.0
6,400-12,800	35	0.0%	491.2	2.2%	38,452.0	9.0	704.0	39,490.0	4,082.0	90.6%	42,427.0
> 12,800	1	0.0%	26.7	0.1%	73,163.0	1.0	2,673.0	75,138.0	15,501.0	82.9%	88,256.0
Total	**458,747**	**100.0%**	**22,075.4**	**100.0%**	**132.0**	**256.8**	**1.5**	**135.0**	**8.9**	**93.8%**	**140.0**

[1] Adjusted by energy-based co-product allocation

Co-product Allocation of Oil

The EIA data also shows that gas wells produce a small share of oil. On an energy basis, oil comprises approximately 3.8 to 17 percent of gas well production, depending on the production rate bracket. Using energy-based, co-product allocation, it is necessary to scale the production rates of the gas wells so they are representative of 100 percent gas production.

For example, a gas well that has daily production rates of 718 Mcf of natural gas and 6.2 barrels of oil has a total daily production of 773 MMBtu of energy. This energy equivalency is calculated using heating values of 1,027 Btu/cf for natural gas and 5.8 MMBtu/bbl for oil. If expressed solely on and energy-equivalent basis of natural gas, 773 MMBtu of energy is equal to 753 Mcf of natural gas. Thus, in this instance, accounting for the co-production of oil increases the nominal production rate of the gas well from 718 Mcf/day to 752 Mcf/day. Note that this nominal rate of 752 Mcf/day does not represent the actual gas produced by the well, but is an LCA accounting method that uses the relative energies of produced oil and natural gas to scale the gas production rate so it is representative of a well that produces only natural gas.

Selection of Representative Production Brackets

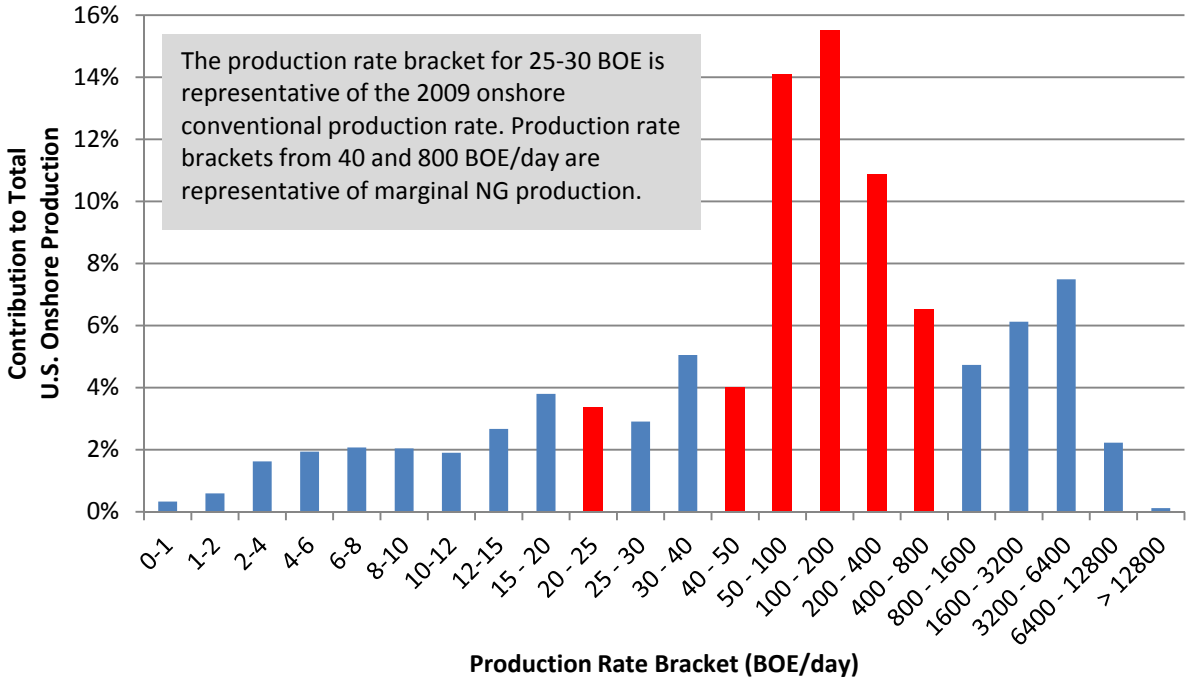
The production rates of onshore conventional natural gas wells vary widely and are a function of reservoir properties, extraction technology, and age. As shown by the EIA data, the production rates of onshore gas wells range from less than 1 BOE/day to more than 12,800 BOE/day. There are not enough data to determine the split between conventional and unconventional wells within each production rate bracket; however, the total production of each bracket and the production rates of unconventional wells can be used to determine the most likely production rates for onshore conventional natural gas. The distribution of gas wells by total gas produced is shown in **Figure A-2**

The production categories in **Table A-15** include a large population of wells in the lowest production rate bracket; 19.8 percent of U.S. onshore natural gas wells produce less than one BOE per day. Similarly, the production rate bracket for 1 - 2 BOE/day includes 9.8 percent of natural gas wells, the production rate bracket for 2 - 4 BOE/day includes 13.3 percent of natural gas wells, and the production rate bracket for 4 - 6 BOE/day includes 9.4 percent of natural gas wells. While these four production rate brackets account for 52 percent of the total count of natural gas wells, they account for only 4.5 percent of total natural gas production.

The average production rate for conventional onshore natural gas wells in 2009 was 66 Mcf per day. This production rate was calculated by dividing the amount of onshore conventional natural gas that was produced in 2009 by the total number of onshore conventional natural gas wells in 2009.

The marginal production rate for conventional onshore natural gas was calculated by selecting the most productive region of the production rate brackets. The production rate brackets that include 40 to 800 BOE/day represent 51 percent of total onshore natural gas production. The average production rate of this range of wells is 592 Mcf/day.

Figure A-2: Distribution of Onshore Natural Gas Wells



A.2 Raw Material Acquisition: Coal

Raw material extraction for coal incorporates extraction profiles for coal derived from the PRB, where sub-bituminous, low-rank coal extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 coal seam, where bituminous coal is extracted from approximately 2 to 15 foot seams via underground longwall and continuous mining. Each modeling approach is described below.

Powder River Basin Coal

The PRB coal-producing region consists of counties in two states – Big Horn, Custer, Powder River, Rosebud, and Treasure in Montana, and Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston in Wyoming (EIA, 2009). PRB coal is advantageous in comparison to bituminous coals in that it has lower ash and sulfur content. However, PRB coal also has a lower heating value than higher rank coals (Clyde Bergemann, 2005). In 2007, there were 17 surface mines extracting PRB coal, which produced over 479 million short tons (EIA, 2009).

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009).

Equipment and Mine Site

Much of the equipment utilized for surface coal mining in the PRB is very large. GHG emissions that result from the production of construction materials required for coal extraction were quantified for the following equipment, within the model: track loader (10 pieces at 26,373 kg each); rotary drill (3 pieces at 113,400 kg each); walking dragline (3 pieces at 7,146,468 kg each); electric mining shovel (10 pieces at 1,256,728 kg each); mining truck (11 pieces at 278,690 kg each); coal crusher (1 piece at 115,212 kg); conveyor (1 piece at 1,064,000 kg); and loading silo (6 pieces at 10,909,569 kg each).

Coal seams are located relatively close to the ground surface in the PRB such that large-scale surface mining is common. The coal seam ranges in thickness from 42 to 184 feet thick (EPA, 2004a). Before overburden drilling and cast blasting can be carried out, topsoil and unconsolidated overburden must be removed from the consolidated overburden that is to be blasted. These operations use both truck and shovel operations and bulldozing to move these materials to a nearby stockpile location so that they can be used in post-mining site reclamation. Estimates are made for topsoil/overburden operations based on requirements reported in the Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002) for a hypothetical western surface coal mine.

Overburden Blasting and Removal

Blast holes are drilled into overburden for subsequent ammonium nitrate and fuel oil packing and detonation using large rotary drills. Drills use electricity to drill 220-270 millimeter diameter holes through sandstone, siltstone, mudstone and carbonaceous shale that make up the overburden. Typically this overburden contains water, which controls particulate emission associated with drilling activities. For the purposes of this assessment it is assumed that drilling operations produce no direct emissions. Electricity requirements for drilling are taken from the U.S. DOE report Mining Industry for the Future: Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002).

Cast blasting is a blasting technique that was developed relatively recently, and has found broad application in large surface mines. Cast blasting comminutes (breaks into fragments/particles) overburden, and also moves an estimated 25-35 percent (modeled at 30 percent) of the blasted overburden to the target fill location (Mining Technology, 2007). The model assumes that blasting uses ammonium nitrate and fuel oil explosives with a powder factor[1] of 300 g per m^3 of overburden blasted (SME, 1990), and GHG emissions associated with explosive production and the blasting process are included in the model, based on EPA's AP-42 report (EPA, 1995).

Overburden removal is achieved primarily through dragline operations, with the remainder moved using large electric shovels. Dragline excavation systems are among the largest on-land machines, and utilize a large bucket suspended from a boom, where the bucket is scraped along the ground to fill the bucket. The bucket is then emptied at a nearby fill location. Electricity requirements for dragline operation combined with other on site operations, were estimated based on electricity usage at the North Antelope Rochelle Mine, to be approximately 971 kWh per 1000 tons of coal (Peabody, 2006). During this time dragline operation accounted for approximately 50% of the overburden energy.

[1] Powder factor refers to the mass of explosive needed to blast a given mass of material.

Coal Recovery

Following overburden removal, coal is extracted using truck and shovel-type operations. Because of the large scale of operations, large electric mining shovels (Bucyrus 495 High Performance Series) are assumed to be employed, with a bucket capacity of 120 tons, alongside 320-400 ton capacity mining trucks (Bucyrus International Inc., 2008).

The amount of coal that could be moved by a single shovel per year was determined by using data for the Black Thunder and Cordero Rojo coal mines (Mining Technology, 2007). A coal hauling distance of two miles is assumed, with a round-trip distance of four miles, based on evaluation of satellite imagery of mining operations. The extracted coal is ground and crushed to the necessary size for transportation. It is assumed that the coal does not require cleaning before leaving the mine site. The crushed coal is carried from the preparation facility to a loading silo by an overland conveyor belt. From the loading silo, the coal is loaded into railcars for transportation.

Coal Bed Methane Emissions

During coal acquisition, methane is released during both the coal extraction and post-mining coal preparation activities. While the PRB has relatively low specific methane content, the large thickness of the coal deposit (80 feet thick or more in many areas) has a large methane content per square foot of surface area. As a result the PRB has recently begun to be exploited on a large scale. Extraction of coal bed methane, prior to mining of the coal seam, results in a net reduction of the total amount of coal bed methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market, and eventually combusted.

For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on recent data available from the EPA, coal bed methane emissions for surface mining, including the PRB, are expected to range from 8 to 98 standard cubic feet per ton (cf/ton) of produced coal, with a typical value of 51 cf/ton (EPA, 2011b).

Illinois No. 6 Coal

Illinois No. 6 coal is part of the Herrin Coal, and is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness, and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. The following sections describe the unit processes modeled for Illinois No. 6 coal mining.

Equipment and Mine Site

Extraction of Illinois No. 6 coal requires several types of major equipment and mining components, in order to operate the coal mine. The following components were modeled for use during underground mining operations: site paving and concrete, conveyor belt, stacker/reclaimer, crusher, coal cleaning, silo, wastewater treatment, continuous miner, longwall mining systems (including shear head, roof supports, armored force conveyor, stage loader, and mobile belt tailpiece), and shuttle car systems with replacement. Overall, when considering materials requirements for the construction of these systems, the material inputs values shown in **Table A-16** were required for mine and mining system construction, on a per lb of coal output basis. GHG emissions associated

with the production of these materials were incorporated into the model and accounted for as construction related emissions.

Table A-16: Construction Materials Required for Illinois No. 6 Coal Mining

Construction Material	Amount	Units
Cold-Rolled Steel	1.47E-05	lb/lb coal produced
Hot-dip Galvanized Steel	1.52E-06	lb/lb coal produced
Rubber	4.45E-07	lb/lb coal produced
Steel Plate	1.80E-04	lb/lb coal produced
Concrete	6.06E-05	lb/lb coal produced
Rebar	1.41E-06	lb/lb coal produced
Polyvinylchloride Pipe	1.30E-07	lb/lb coal produced
Steel, Stainless, 316	6.77E-08	lb/lb coal produced
Stainless Steel Cold Roll 431	6.77E-08	lb/lb coal produced
Cast Iron	3.38E-07	lb/lb coal produced
Copper Mix	8.11E-09	lb/lb coal produced
Asphalt	1.11E-03	lb/lb coal produced

Coal Mine Operations

Operations of the coal mine were based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations. Electricity use for this model was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008). The life cycle profile for electricity use is based on eGRID2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems (EPA, 2010).

Although no Galatia Mine data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary on-site operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004). Emissions of GHGs were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004b).

Coal Bed Methane

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as PRB coals, and as a result are less commonly utilized as a resource for coal bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the EPA, coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 cf/ton of produced

coal, with a nominal value of 422 cf/ton (EPA, 2011b). It is assumed that no methane capture is applied for Illinois No. 6 coal.

A.3 Raw Material Transport: Natural Gas

The boundary of raw material transport begins with receipt of processed natural gas at the extraction site and ends with the delivery of natural gas to an energy conversion facility. Methane emissions from pipeline operations are a function of pipeline distance. This analysis uses a pipeline transport distance of 604 miles (971.4 km), which is the average distance for natural gas pipeline transmission in the U.S. The data sources and assumptions for calculating the greenhouse gas emissions from construction and operation of natural gas transmission pipelines are discussed below.

Pipeline Construction and Decommissioning

Carbon steel is the primary material used in the construction of natural gas pipelines. The mass of pipeline per unit length was determined using an online calculator (Steel Pipes & Tubes, 2009). The weight of valves and fittings were estimated at an additional 10 percent of the total pipeline weight. The pipeline was assumed to have a life of 30 years. The mass of pipeline construction per kilogram of natural gas was determined by dividing the total pipeline weight by the total natural gas flow through the pipeline for a 30-year period.

The decommissioning of a natural gas pipeline involves cleaning and capping activities. This analysis assumes that the decommissioning of a natural gas pipeline incurs 10 percent of the energy requirements and emissions as the original installation of the pipeline.

Pipeline Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used.

A 2008 paper published by the Interstate Natural Gas Association of America provides data from its 2004 database, which shows that the U.S. pipeline transmission network has 5,400 reciprocating compressors and over 1,000 gas turbine compressors (Hedman, 2008). Further, based on written communication from El Paso Pipeline Group, approximately three percent of transmission compressors are electrically driven (El Paso Pipeline Group, 2011). El Paso Pipeline Group has the highest transmission capacity of all natural gas pipeline companies in the U.S., and it is thus assumed that the share of electrically-powered compressors in their fleet is representative of the entire natural gas transmission network. Based on written communication with El Paso Pipeline Group (El Paso Pipeline Group, 2011), the share of compressors on the U.S. natural gas pipeline transmission network is approximately 78 percent reciprocating compressors, 19 percent turbine-powered centrifugal compressors, and 3 percent electrically-powered compressors.

The use rate of natural gas for fuel in transmission compressors was calculated from the Federal Energy Regulatory Commission (FERC) Form 2 database, which is based on an annual survey of gas producers and pipeline companies (FERC, 2010). The 28 largest pipeline companies were pulled from the FERC Form 2 database. These 28 companies represent 81 percent of NG transmission in 2008. The FERC data for 81 percent of U.S. natural gas transmission is assumed to be a representative sample of the fuel use rate of the entire transmission network. This data shows that

0.96 percent of natural gas product is consumed as compressor fuel. This fuel use rate was converted to a basis of kg of natural gas consumed per kg of natural gas transported by multiplying it by the total natural gas delivered by the transmission network in 2008 (EIA, 2011) and dividing it by the annual tonne-km of pipeline transmission in the U.S. (Dennis, 2005). The total delivery of natural gas in 2008 was 21 Tcf, which is approximately 400 billion kg of natural gas. The annual transport rate for natural gas transmission was steady from 1995 through 2003, at approximately 380 billion tonne-km per year. More recent transportation data are not available, and thus this analysis assumes the same tonne-km rate for 2008 as shown from 1995 through 2003.

The air emissions from the combustion of natural gas by compressors are estimated by applying EPA emission factors to the natural gas consumption rate of the compressors (EPA, 1995). Specifically, the emission profile of gas-powered, centrifugal compressors is based on emission factors for gas turbines; the emission profile of gas-powered, reciprocating compressors is based on emission factors for 4-stroke, lean burn engines. For electrically-powered compressors, this analysis assumes that the indirect emissions are representative of the U.S. average fuel mix for electricity generation.

The average power of electrically-driven compressors for U.S. NG transmission is assumed to be the same as the average power of all compressors on the transmission network. An average compressor on the U.S. natural gas transmission network has a power rating of 14,055 horsepower (10.5 MW) and a throughput of 734 million cubic feet of natural gas per day (583,000 kg NG/hour) (EIA, 2007). Electrically-driven compressors have efficiencies of 95 percent (DOE, 1996; Hedman, 2008). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output.

In addition to air emissions from combustion processes, fugitive venting from pipeline equipment results in the methane emissions to air. The fugitive emission rate for natural gas pipeline operations is based on data published by the Bureau of Transportation Statistics (BTS) and EPA. The transport data for natural gas transmission is based on ton-mileage estimates by BTS, which calculates 253 billion ton-miles of natural gas transmission in 2003 (Dennis, 2005). The 2003 data are the most recent data point in the BTS reference, and thus EPA's inventory data for the years 2000 and 2005 were interpolated to arrive at a year 2003 value of 1,985 million kg of fugitive methane emissions per year (EPA, 2011b). Dividing the EPA emission by the transport requirements and converting to metric units gives 5.37E-06 kg/kg-km.

Calculation of Average Natural Gas Transmission Distance

The average pipeline distance for natural gas transport is determined by balancing national emission inventory (EPA, 2011b) and natural gas consumption data (EIA, 2011) with NETL's unit process emission factor for fugitive methane emissions from pipeline operations. **Equation 5** shows the national inventory and consumption data on the left-hand side and NETL's emission factor for fugitive methane on the right-hand side.

$$\frac{E_{methane}}{NG_{consumption}} = d * EF_{methane} \qquad \textbf{(Equation 5)}$$

Where,

$E_{methane}$ = Total pipeline fugitive methane emissions (default = 2,115E+06 kg CH_4/yr)
$NG_{consumption}$ = consumption of natural gas (default = 21.84 MMBtu/yr)
$EF_{methane}$ = Emission factor for fugitive methane (default =9.97E-05 kg CH_4/MMBtu-km)

The default value for total fugitive emissions of methane from pipeline transmission are based on the 2009 national inventory emissions for natural gas transmission and storage reported by EPA (EPA, 2011b). The value reported by EPA is 2,115 Gg CH_4/yr, which is equal to 2,115 million kg CH_4/yr.

The default value for annual natural gas consumption is based on annual EIA statistics for natural gas production and consumption (EIA, 2011). The volume of natural gas transported by pipeline is 21.26 Tcf/year. This value is the midpoint of the volume of processed natural gas injected to the pipeline transmission network and the volume of natural gas delivered to consumers. In 2009 the volume of natural gas injected to the natural gas transmission network by NG processing plants was 21.56 Tcf; this volume was calculated by subtracting the natural gas consumption at the extraction and processing sites (1.28 Tcf) from total annual consumption (22.84 Tcf) (EIA, 2011). In 2009 the volume of natural gas delivered to consumers was 20.97 Tcf (EIA, 2011). The average volume of natural gas transmission was converted to an energy basis using an energy density of 1,027 Btu/cf; 21.26 Tcf/year is equivalent to 21.84 E+09 MMBtu. Converting to an energy basis (using a density of 0.042 lbs/cf and energy content of 1,027 Btu/cf) gives 21.84 billion MMBtu.

For **Equation 5** it is necessary to convert the emission factor for fugitive emissions from pipeline operations (calculated above) to an energy basis so that it can be factored with the annual consumption data for natural gas. The emission factor used by the pipeline unit process is 5.37E-06 kg/kg-km. Converting to an energy basis (using the conversion factors of 0.042 lb/cf NG and 1,027 Btu/cf) results in an emission factor of 9.97E-05 kg CH_4/MMBtu-km.

The unknown *d* in **Equation 5** is the distance (km) that reconciles NETL's unit process with the national level data. Solving for *d* gives the following equation:

$$d = \frac{E_{methane}}{NG_{consumption} * EF_{methane}} \qquad \textbf{(Equation 6)}$$

Applying the default values to **Equation 6** gives a distance of 971 km (604 miles), as shown in **Equation 7**.

$$d = \frac{2{,}115\times10^{6} kg\ CH_4/yr}{(21.84\times10^{9} MMBtu/yr)(9.97\times10^{-5} kg CH_4/MMBtu\ km)} = 971\ km \qquad \textbf{(Equation 7)}$$

The pipeline transport of natural gas results in losses of natural gas product to two activities: (1) fugitive emissions and (2) natural gas used as fuel in pipeline compressors. Based on the data and assumptions of this unit process, the transmission of natural gas a distance of 971 km results in a 1.45 percent loss of natural gas product (1.0148 kg of natural gas are injected into the pipeline to deliver 1.0 kg of natural gas to the consumer). The annual data for natural gas production and consumption (EIA, 2011) show a 2.81 percent loss of natural gas for transmission and distribution (natural gas processing plants produce 21.56 Tcf of natural gas and 20.97 Tcf of natural gas are delivered to consumers). The 2.81 percentage loss factor includes pipeline *distribution* in addition to pipeline transmission, and thus it is expected for the transmission losses (1.45 percent) to be lower than the transmission and distribution loss (2.81 percent).

The default values for key variables for NETL's model of natural gas pipeline transmission are shown in the **Table A-17**.

Table A-17: Natural Gas Transport to Large End User

Natural Gas Emissions and Transmission Infrastructure	Units	Value
Pipeline Transport Distance (national average)	Miles	604
Distance Between Compressor Stations	Miles	75
Compression, Gas-powered, Reciprocating Engine	Percent	78%
Compression, Gas-powered, Centrifugal Engine	Percent	19%
Compression, Electrical, Centrifugal Engine	Percent	3%

A.4 Raw Material Transport: Coal

Train transport was modeled for the transport of both PRB and Illinois No. 6 coal from mining sites to energy conversion facilities. Mined coal is presumed to be transported by rail from PRB and Illinois No. 6 coal mine sources, in support of electricity production. Coal is assumed to be transported via unit train, where a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each car has a 100-ton coal capacity (NETL, 2007).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. It is assumed that the majority of the railway connecting the coal mine and the energy conversion facility is existing infrastructure. An assumed 25-mile rail spur was constructed between the energy conversion facility and the primary railway.

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Appendix B:
Inventory Results in Alternate Units

Table B-1: Upstream Greenhouse Gas Inventory Results for Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Gas	CO_2	5.93E+00	1.05E+00	6.98E+00	2.69E+00	4.76E-01	3.16E+00	2.55E+00	4.51E-04	3.00E-03	1.22E+01	2.16E+00	1.43E+01
	N_2O	1.85E-04	2.02E-05	2.05E-04	8.39E-05	9.17E-06	9.31E-05	7.95E-05	8.69E-06	8.82E-05	3.80E-04	4.15E-05	4.22E-04
	CH_4	6.42E-01	2.14E-01	8.56E-01	2.91E-01	9.69E-02	3.88E-01	2.76E-01	9.18E-02	3.68E-01	1.32E+00	4.39E-01	1.76E+00
	CO_2e (20-year)	52.2	16.4	68.6	23.7	7.5	31.1	22.4	7.1	29.5	107.2	33.8	141.0
	CO_2e (100-year)	22.0	6.4	28.4	10.0	2.9	12.9	9.5	2.7	12.2	45.3	13.1	58.4
	CO_2e (500-year)	10.8	2.7	13.5	4.9	1.2	6.1	4.7	1.2	5.8	22.3	5.5	27.8
Conv. Gas	CO_2	6.34E+00	1.05E+00	7.38E+00	2.87E+00	4.76E-01	3.35E+00	2.72E+00	4.51E-01	3.17E+00	1.30E+01	2.16E+00	1.52E+01
	N_2O	2.14E-04	2.02E-05	2.35E-04	9.72E-05	9.17E-06	1.06E-04	9.22E-05	8.69E-06	1.01E-04	4.40E-04	4.15E-05	4.82E-04
	CH_4	5.29E-01	2.14E-01	7.43E-01	2.40E-01	9.69E-02	3.37E-01	2.28E-01	9.18E-02	3.19E-01	1.09E+00	4.39E-01	1.53E+00
	CO_2e (20-year)	44.5	16.4	60.9	20.2	7.5	27.6	19.1	7.1	26.2	91.4	33.8	125.2
	CO_2e (100-year)	19.6	6.4	26.0	8.9	2.9	11.8	8.4	2.7	11.2	40.3	13.1	53.5
	CO_2e (500-year)	10.4	2.7	13.1	4.7	1.2	5.9	4.5	1.2	5.6	21.3	5.5	26.8
UnConv. Gas	CO_2	5.60E+00	1.05E+00	6.65E+00	2.54E+00	4.76E-01	3.02E+00	2.41E+00	4.51E-01	2.86E+00	1.15E+01	2.16E+00	1.37E+01
	N_2O	1.62E-04	2.02E-05	1.82E-04	7.33E-05	9.17E-06	8.25E-05	6.95E-05	8.69E-06	7.82E-05	3.32E-04	4.15E-05	3.74E-04
	CH_4	7.32E-01	2.14E-01	9.45E-01	3.32E-01	9.69E-02	4.29E-01	3.15E-01	9.18E-02	4.06E-01	1.50E+00	4.39E-01	1.94E+00
	CO_2e (20-year)	58.3	16.4	74.8	26.5	7.5	33.9	25.1	7.1	32.1	119.8	33.8	153.6
	CO_2e (100-year)	23.9	6.4	30.3	10.9	2.9	13.8	10.3	2.7	13.0	49.2	13.1	62.3
	CO_2e (500-year)	11.2	2.7	13.9	5.1	1.2	6.3	4.8	1.2	6.0	23.0	5.5	28.5
Onshore Gas	CO_2	7.18E+00	1.05E+00	8.23E+00	3.26E+00	4.76E-01	3.74E+00	3.09E+00	4.51E-01	3.54E+00	1.48E+01	2.16E+00	1.69E+01
	N_2O	2.13E-04	2.02E-05	2.33E-04	9.66E-05	9.17E-06	1.06E-04	9.16E-05	8.69E-06	1.00E-04	4.38E-04	4.15E-05	4.79E-04
	CH_4	8.21E-01	2.14E-01	1.03E+00	3.72E-01	9.69E-02	4.69E-01	3.53E-01	9.18E-02	4.45E-01	1.69E+00	4.39E-01	2.12E+00
	CO_2e (20-year)	66.3	16.4	82.8	30.1	7.5	37.5	28.5	7.1	35.6	136.3	33.8	170.0
	CO_2e (100-year)	27.8	6.4	34.2	12.6	2.9	15.5	11.9	2.7	14.7	57.0	13.1	70.2
	CO_2e (500-year)	13.5	2.7	16.1	6.1	1.2	7.3	5.8	1.2	6.9	27.6	5.5	33.1
Offshore Gas	CO_2	5.37E+00	1.05E+00	6.42E+00	2.44E+00	4.76E-01	2.91E+00	2.31E+00	4.51E-01	2.76E+00	1.10E+01	2.16E+00	1.32E+01
	N_2O	2.55E-04	2.02E-05	2.75E-04	1.15E-04	9.17E-06	1.25E-04	1.09E-04	8.69E-06	1.18E-04	5.23E-04	4.15E-05	5.64E-04
	CH_4	9.71E-02	2.14E-01	3.11E-01	4.40E-02	9.69E-02	1.41E-01	4.17E-02	9.18E-02	1.34E-01	1.99E-01	4.39E-01	6.38E-01
	CO_2e (20-year)	12.4	16.4	28.9	5.6	7.5	13.1	5.3	7.1	12.4	25.5	33.8	59.3
	CO_2e (100-year)	7.9	6.4	14.3	3.6	2.9	6.5	3.4	2.7	6.1	16.2	13.1	29.3
	CO_2e (500-year)	6.1	2.7	8.8	2.8	1.2	4.0	2.6	1.2	3.8	12.6	5.5	18.1
Assoc. Gas	CO_2	5.04E+00	1.05E+00	6.09E+00	2.29E+00	4.76E-01	2.76E+00	2.17E+00	4.51E-01	2.62E+00	1.04E+01	2.16E+00	1.25E+01
	N_2O	1.42E-04	2.02E-05	1.62E-04	6.42E-05	9.17E-06	7.34E-05	6.09E-05	8.69E-06	6.96E-05	2.91E-04	4.15E-05	3.32E-04
	CH_4	2.82E-01	2.14E-01	4.96E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.80E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.4	16.4	41.8	11.5	7.5	19.0	10.9	7.1	18.0	52.2	33.8	85.9
	CO_2e (100-year)	12.1	6.4	18.5	5.5	2.9	8.4	5.2	2.7	8.0	24.9	13.1	38.1
	CO_2e (500-year)	7.2	2.7	9.9	3.3	1.2	4.5	3.1	1.2	4.2	14.8	5.5	20.3

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
CBM Gas	CO_2	5.45E+00	1.05E+00	6.50E+00	2.47E+00	4.76E-01	2.95E+00	2.34E+00	4.51E-01	2.79E+00	1.12E+01	2.16E+00	1.33E+01
	N_2O	1.55E-04	2.02E-05	1.75E-04	7.03E-05	9.17E-06	7.95E-05	6.67E-05	8.69E-06	7.53E-05	3.18E-04	4.15E-05	3.60E-04
	CH_4	2.86E-01	2.14E-01	5.00E-01	1.30E-01	9.69E-02	2.27E-01	1.23E-01	9.18E-02	2.15E-01	5.88E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.1	16.4	42.5	11.8	7.5	19.3	11.2	7.1	18.3	53.6	33.8	87.4
	CO_2e (100-year)	12.7	6.4	19.1	5.7	2.9	8.6	5.4	2.7	8.2	26.0	13.1	39.1
	CO_2e (500-year)	7.7	2.7	10.3	3.5	1.2	4.7	3.3	1.2	4.4	15.7	5.5	21.2
Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
LNG Gas	CO_2	2.93E+01	1.05E+00	3.04E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.31E+01	6.02E+01	2.16E+00	6.24E+01
	N_2O	3.42E-04	2.02E-05	3.62E-04	1.55E-04	9.17E-06	1.64E-04	1.47E-04	8.69E-06	1.56E-04	7.02E-04	4.15E-05	7.44E-04
	CH_4	2.78E-01	2.14E-01	4.91E-01	1.26E-01	9.69E-02	2.23E-01	1.19E-01	9.18E-02	2.11E-01	5.70E-01	4.39E-01	1.01E+00
	CO_2e (20-year)	49.4	16.4	65.8	22.4	7.5	29.9	21.2	7.1	28.3	101.5	33.8	135.2
	CO_2e (100-year)	36.4	6.4	42.8	16.5	2.9	19.4	15.6	2.7	18.4	74.7	13.1	87.8
	CO_2e (500-year)	31.5	2.7	34.2	14.3	1.2	15.5	13.5	1.2	14.7	64.7	5.5	70.1

Table B-2: Upstream Greenhouse Gas Inventory Results for Marginal Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Onshore Gas	CO_2	5.11E+00	1.05E+00	6.16E+00	2.32E+00	4.76E-01	2.79E+00	2.20E+00	4.51E-01	2.65E+00	1.05E+01	2.16E+00	1.26E+01
	N_2O	1.44E-04	2.02E-05	1.64E-04	6.53E-05	9.17E-06	7.44E-05	6.19E-05	8.69E-06	7.06E-05	2.96E-04	4.15E-05	3.37E-04
	CH_4	3.41E-01	2.14E-01	5.55E-01	1.55E-01	9.69E-02	2.52E-01	1.47E-01	9.18E-02	2.38E-01	7.01E-01	4.39E-01	1.14E+00
	CO_2e (20-year)	29.7	16.4	46.1	13.5	7.5	20.9	12.8	7.1	19.8	61.0	33.8	94.8
	CO_2e (100-year)	13.7	6.4	20.1	6.2	2.9	9.1	5.9	2.7	8.6	28.1	13.1	41.2
	CO_2e (500-year)	7.7	2.7	10.4	3.5	1.2	4.7	3.3	1.2	4.5	15.9	5.5	21.4
Marg. Offshore Gas	CO_2	5.34E+00	1.05E+00	6.39E+00	2.42E+00	4.76E-01	2.90E+00	2.30E+00	4.51E-01	2.75E+00	1.10E+01	2.16E+00	1.31E+01
	N_2O	2.54E-04	2.02E-05	2.74E-04	1.15E-04	9.17E-06	1.24E-04	1.09E-04	8.69E-06	1.18E-04	5.21E-04	4.15E-05	5.62E-04
	CH_4	9.01E-02	2.14E-01	3.04E-01	4.09E-02	9.69E-02	1.38E-01	3.87E-02	9.18E-02	1.31E-01	1.85E-01	4.39E-01	6.24E-01
	CO_2e (20-year)	11.9	16.4	28.3	5.4	7.5	12.9	5.1	7.1	12.2	24.4	33.8	58.2
	CO_2e (100-year)	7.7	6.4	14.1	3.5	2.9	6.4	3.3	2.7	6.0	15.8	13.1	28.9
	CO_2e (500-year)	6.1	2.7	8.7	2.8	1.2	4.0	2.6	1.2	3.8	12.5	5.5	18.0

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Assoc. Gas	CO_2	4.91E+00	1.05E+00	5.96E+00	2.23E+00	4.76E-01	2.70E+00	2.11E+00	4.51E-01	2.56E+00	1.01E+01	2.16E+00	1.22E+01
	N_2O	1.37E-04	2.02E-05	1.57E-04	6.22E-05	9.17E-06	7.14E-05	5.90E-05	8.69E-06	6.77E-05	2.82E-04	4.15E-05	3.23E-04
	CH_4	2.82E-01	2.14E-01	4.95E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.78E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.2	16.4	41.7	11.4	7.5	18.9	10.8	7.1	17.9	51.8	33.8	85.6
	CO_2e (100-year)	12.0	6.4	18.4	5.4	2.9	8.3	5.2	2.7	7.9	24.6	13.1	37.8
	CO_2e (500-year)	7.1	2.7	9.7	3.2	1.2	4.4	3.0	1.2	4.2	14.5	5.5	20.0
Marg. Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	SF_6	6.49E-09	2.50E-09	8.99E-09	2.94E-09	1.13E-09	4.08E-09	2.79E-09	1.07E-09	3.86E-09	1.33E-08	5.13E-09	1.85E-08
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
Marg. Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
Marg. CBM Gas	CO_2	5.67E+00	1.05E+00	6.72E+00	2.57E+00	4.76E-01	3.05E+00	2.44E+00	4.51E-01	2.89E+00	1.16E+01	2.16E+00	1.38E+01
	N_2O	1.62E-04	2.02E-05	1.83E-04	7.36E-05	9.17E-06	8.28E-05	6.98E-05	8.69E-06	7.85E-05	3.33E-04	4.15E-05	3.75E-04
	CH_4	2.88E-01	2.14E-01	5.02E-01	1.31E-01	9.69E-02	2.28E-01	1.24E-01	9.18E-02	2.16E-01	5.92E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.5	16.4	42.9	12.0	7.5	19.5	11.4	7.1	18.4	54.4	33.8	88.1
	CO_2e (100-year)	12.9	6.4	19.3	5.9	2.9	8.8	5.6	2.7	8.3	26.6	13.1	39.7
	CO_2e (500-year)	7.9	2.7	10.6	3.6	1.2	4.8	3.4	1.2	4.5	16.2	5.5	21.7
Marg. LNG Gas	CO_2	2.93E+01	1.05E+00	3.03E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.30E+01	6.01E+01	2.16E+00	6.23E+01
	N_2O	3.41E-04	2.02E-05	3.61E-04	1.54E-04	9.17E-06	1.64E-04	1.46E-04	8.69E-06	1.55E-04	7.00E-04	4.15E-05	7.41E-04
	CH_4	2.70E-01	2.14E-01	4.83E-01	1.22E-01	9.69E-02	2.19E-01	1.16E-01	9.18E-02	2.08E-01	5.54E-01	4.39E-01	9.92E-01
	CO_2e (20-year)	48.8	16.4	65.2	22.1	7.5	29.6	21.0	7.1	28.0	100.2	33.8	133.9
	CO_2e (100-year)	36.1	6.4	42.5	16.4	2.9	19.3	15.5	2.7	18.3	74.2	13.1	87.3
	CO_2e (500-year)	31.4	2.7	34.1	14.2	1.2	15.4	13.5	1.2	14.6	64.5	5.5	69.9

Table B-3: Upstream Greenhouse Gas Inventory Results for Coal

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Coal	CO_2	1.32E+00	1.33E+00	2.64E+00	5.97E-01	6.02E-01	1.20E+00	5.66E-01	5.71E-01	1.14E+00
	N_2O	5.29E-04	3.21E-05	5.61E-04	2.40E-04	1.46E-05	2.54E-04	2.27E-04	1.38E-05	2.41E-04
	CH_4	3.78E-01	7.23E-04	3.79E-01	1.72E-01	3.28E-04	1.72E-01	1.63E-01	3.11E-04	1.63E-01
	CO_2e (20-year)	28.7	1.4	30.1	13.0	0.6	13.7	12.3	0.6	12.9
	CO_2e (100-year)	10.9	1.4	12.3	5.0	0.6	5.6	4.7	0.6	5.3
	CO_2e (500-year)	4.3	1.3	5.6	1.9	0.6	2.5	1.8	0.6	2.4
Illinois No. 6 Coal	CO_2	2.53E+00	1.33E+00	3.86E+00	1.15E+00	6.02E-01	1.75E+00	1.09E+00	5.71E-01	1.66E+00
	N_2O	3.97E-05	3.21E-05	7.18E-05	1.80E-05	1.46E-05	3.26E-05	1.71E-05	1.38E-05	3.09E-05
	CH_4	9.40E-01	7.23E-04	9.41E-01	4.27E-01	3.28E-04	4.27E-01	4.04E-01	3.11E-04	4.05E-01
	SF_6	4.98E-07	5.47E-12	4.98E-07	2.26E-07	2.48E-12	2.26E-07	2.14E-07	2.35E-12	2.14E-07
	CO_2e (20-year)	70.3	1.4	71.7	31.9	0.6	32.5	30.2	0.6	30.8
	CO_2e (100-year)	26.1	1.4	27.4	11.8	0.6	12.4	11.2	0.6	11.8
	CO_2e (500-year)	9.7	1.3	11.0	4.4	0.6	5.0	4.2	0.6	4.7
PRB Coal	CO_2	7.73E-01	1.33E+00	2.10E+00	3.51E-01	6.02E-01	9.53E-01	3.32E-01	5.71E-01	9.03E-01
	N_2O	7.48E-04	3.21E-05	7.80E-04	3.39E-04	1.46E-05	3.54E-04	3.22E-04	1.38E-05	3.35E-04
	CH_4	1.26E-01	7.23E-04	1.26E-01	5.70E-02	3.28E-04	5.74E-02	5.41E-02	3.11E-04	5.44E-02
	CO_2e (20-year)	10.0	1.4	11.4	4.6	0.6	5.2	4.3	0.6	4.9
	CO_2e (100-year)	4.1	1.4	5.5	1.9	0.6	2.5	1.8	0.6	2.4
	CO_2e (500-year)	1.8	1.3	3.2	0.8	0.6	1.4	0.8	0.6	1.4

Table B-4: Upstream Greenhouse Gas Inventory Results for Natural Gas-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Gas)	CO_2	5.81E+01	1.01E+01	8.75E+02	0.00E+00	9.43E+02	2.63E+01	4.60E+00	3.97E+02	0.00E+00	4.28E+02	7.31E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	1.81E-03	1.96E-04	2.45E-03	0.00E+00	4.45E-03	8.22E-04	8.88E-05	1.11E-03	0.00E+00	2.02E-03	2.28E-04	2.47E-05	3.08E-04	0.00E+00	5.61E-04
	CH_4	6.31E+00	2.09E+00	2.44E-02	0.00E+00	8.42E+00	2.86E+00	9.46E-01	1.11E-02	0.00E+00	3.82E+00	7.95E-01	2.63E-01	3.07E-03	0.00E+00	1.06E+00
	SF_6	4.80E-07	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.18E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	6.04E-08	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	513.0	160.4	877.0	5.2	1,555.6	232.7	72.8	397.8	2.3	705.6	64.6	20.2	110.5	0.6	196.0
	CO_2e (100-year)	216.4	62.4	875.9	7.2	1,161.8	98.2	28.3	397.3	3.3	527.0	27.3	7.9	110.4	0.9	146.4
	CO_2e (500-year)	106.3	26.0	875.1	10.3	1,017.7	48.2	11.8	396.9	4.7	461.6	13.4	3.3	110.3	1.3	128.2
Fleet Baseload (Conv. Gas)	CO_2	6.22E+01	1.01E+01	8.75E+02	0.00E+00	9.47E+02	2.82E+01	4.60E+00	3.97E+02	0.00E+00	4.30E+02	7.84E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	2.10E-03	1.96E-04	2.45E-03	0.00E+00	4.75E-03	9.55E-04	8.88E-05	1.11E-03	0.00E+00	2.15E-03	2.65E-04	2.47E-05	3.08E-04	0.00E+00	5.98E-04
	CH_4	5.26E+00	2.09E+00	2.44E-02	0.00E+00	7.37E+00	2.38E+00	9.46E-01	1.11E-02	0.00E+00	3.34E+00	6.62E-01	2.63E-01	3.07E-03	0.00E+00	9.28E-01
	SF_6	5.26E-08	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.39E-08	1.99E-12	0.00E+00	1.43E-04	1.43E-04	6.63E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	441.3	160.4	877.0	5.2	1,483.9	200.2	72.8	397.8	2.3	673.1	55.6	20.2	110.5	0.6	187.0
	CO_2e (100-year)	194.3	62.4	875.9	7.2	1,139.7	88.1	28.3	397.3	3.3	517.0	24.5	7.9	110.4	0.9	143.6
	CO_2e (500-year)	102.5	26.0	875.1	10.3	1,013.9	46.5	11.8	396.9	4.7	459.9	12.9	3.3	110.3	1.3	127.8

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (UnConv. Gas)	CO_2	5.47E+01	1.01E+01	8.75E+02	0.00E+00	9.39E+02	2.48E+01	4.60E+00	3.97E+02	0.00E+00	4.26E+02	6.90E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.58E-03	1.96E-04	2.45E-03	0.00E+00	4.22E-03	7.17E-04	8.88E-05	1.11E-03	0.00E+00	1.91E-03	1.99E-04	2.47E-05	3.08E-04	0.00E+00	5.32E-04
	CH_4	7.15E+00	2.09E+00	2.44E-02	0.00E+00	9.26E+00	3.24E+00	9.46E-01	1.11E-02	0.00E+00	4.20E+00	9.01E-01	2.63E-01	3.07E-03	0.00E+00	1.17E+00
	SF_6	8.20E-07	4.38E-12	0.00E+00	3.16E-04	3.17E-04	3.72E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	1.03E-07	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	570.1	160.4	877.0	5.2	1,612.7	258.6	72.8	397.8	2.3	731.5	71.8	20.2	110.5	0.6	203.2
	CO_2e (100-year)	234.0	62.4	875.9	7.2	1,179.5	106.1	28.3	397.3	3.3	535.0	29.5	7.9	110.4	0.9	148.6
	CO_2e (500-year)	109.4	26.0	875.1	10.3	1,020.8	49.6	11.8	396.9	4.7	463.0	13.8	3.3	110.3	1.3	128.6
Fleet Baseload (Marg. Onshore Gas)	CO_2	4.99E+01	1.01E+01	8.75E+02	0.00E+00	9.35E+02	2.26E+01	4.60E+00	3.97E+02	0.00E+00	4.24E+02	6.29E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.41E-03	1.96E-04	2.45E-03	0.00E+00	4.05E-03	6.38E-04	8.88E-05	1.11E-03	0.00E+00	1.84E-03	1.77E-04	2.47E-05	3.08E-04	0.00E+00	5.10E-04
	CH_4	3.33E+00	2.09E+00	2.44E-02	0.00E+00	5.44E+00	1.51E+00	9.46E-01	1.11E-02	0.00E+00	2.47E+00	4.20E-01	2.63E-01	3.07E-03	0.00E+00	6.86E-01
	SF_6	9.27E-09	4.38E-12	0.00E+00	3.16E-04	3.16E-04	4.20E-09	1.99E-12	0.00E+00	1.43E-04	1.43E-04	1.17E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	290.4	160.4	877.0	5.2	1,332.9	131.7	72.8	397.8	2.3	604.6	36.6	20.2	110.5	0.6	167.9
	CO_2e (100-year)	133.7	62.4	875.9	7.2	1,079.1	60.6	28.3	397.3	3.3	489.5	16.8	7.9	110.4	0.9	136.0
	CO_2e (500-year)	75.5	26.0	875.1	10.3	986.9	34.2	11.8	396.9	4.7	447.6	9.5	3.3	110.3	1.3	124.3
GTSC (Avg. Gas)	CO_2	7.26E+01	1.27E+01	1.33E+03	0.00E+00	1.42E+03	3.29E+01	5.75E+00	6.04E+02	0.00E+00	6.42E+02	9.15E+00	1.60E+00	1.68E+02	0.00E+00	1.78E+02
	N_2O	2.27E-03	2.45E-04	2.86E-05	0.00E+00	2.54E-03	1.03E-03	1.11E-04	1.30E-05	0.00E+00	1.15E-03	2.86E-04	3.08E-05	3.61E-06	0.00E+00	3.20E-04
	CH_4	7.90E+00	2.61E+00	2.64E-03	0.00E+00	1.05E+01	3.58E+00	1.18E+00	1.20E-03	0.00E+00	4.77E+00	9.95E-01	3.29E-01	3.32E-04	0.00E+00	1.32E+00
	SF_6	6.00E-07	5.48E-12	4.34E-08	3.16E-04	3.17E-04	2.72E-07	2.48E-12	1.97E-08	1.43E-04	1.44E-04	7.56E-08	6.90E-13	5.47E-09	3.98E-05	3.99E-05
	CO_2e (20-year)	641.8	200.7	1,330.7	5.2	2,178.4	291.1	91.0	603.6	2.3	988.1	80.9	25.3	167.7	0.6	274.5
	CO_2e (100-year)	270.7	78.0	1,330.6	7.2	1,686.6	122.8	35.4	603.6	3.3	765.0	34.1	9.8	167.7	0.9	212.5
	CO_2e (500-year)	133.0	32.6	1,330.6	10.3	1,506.4	60.3	14.8	603.5	4.7	683.3	16.8	4.1	167.6	1.3	189.8
NGCC (Avg. Gas)	CO_2	4.71E+01	8.23E+00	8.66E+02	0.00E+00	9.22E+02	2.14E+01	3.73E+00	3.93E+02	0.00E+00	4.18E+02	5.94E+00	1.04E+00	1.09E+02	0.00E+00	1.16E+02
	N_2O	1.47E-03	1.59E-04	3.33E-05	0.00E+00	1.66E-03	6.67E-04	7.21E-05	1.51E-05	0.00E+00	7.55E-04	1.85E-04	2.00E-05	4.20E-06	0.00E+00	2.10E-04
	CH_4	5.12E+00	1.69E+00	1.31E-03	0.00E+00	6.82E+00	2.32E+00	7.68E-01	5.94E-04	0.00E+00	3.09E+00	6.46E-01	2.13E-01	1.65E-04	0.00E+00	8.59E-01
	SF_6	3.89E-07	3.55E-12	7.55E-07	3.16E-04	3.17E-04	1.77E-07	1.61E-12	3.42E-07	1.43E-04	1.44E-04	4.91E-08	4.48E-13	9.51E-08	3.98E-05	4.00E-05
	CO_2e (20-year)	416.5	130.2	866.5	5.2	1,418.5	188.9	59.1	393.1	2.3	643.4	52.5	16.4	109.2	0.6	178.7
	CO_2e (100-year)	175.7	50.6	866.5	7.2	1,100.0	79.7	23.0	393.0	3.3	499.0	22.1	6.4	109.2	0.9	138.6
	CO_2e (500-year)	86.3	21.1	866.5	10.3	984.2	39.2	9.6	393.0	4.7	446.4	10.9	2.7	109.2	1.3	124.0
NGCC/ccs (Avg. Gas)	CO_2	5.52E+01	9.65E+00	1.13E+02	0.00E+00	1.78E+02	2.51E+01	4.38E+00	5.13E+01	0.00E+00	8.07E+01	6.96E+00	1.22E+00	1.42E+01	0.00E+00	2.24E+01
	N_2O	1.72E-03	1.86E-04	5.18E-05	0.00E+00	1.96E-03	7.82E-04	8.45E-05	2.35E-05	0.00E+00	8.90E-04	2.17E-04	2.35E-05	6.53E-06	0.00E+00	2.47E-04
	CH_4	6.01E+00	1.99E+00	1.71E-03	0.00E+00	7.99E+00	2.72E+00	9.01E-01	7.78E-04	0.00E+00	3.63E+00	7.57E-01	2.50E-01	2.16E-04	0.00E+00	1.01E+00
	SF_6	4.57E-07	4.16E-12	8.81E-07	3.16E-04	3.17E-04	2.07E-07	1.89E-12	4.00E-07	1.43E-04	1.44E-04	5.75E-08	5.25E-13	1.11E-07	3.98E-05	4.00E-05
	CO_2e (20-year)	488.2	152.7	113.2	5.2	759.2	221.5	69.2	51.3	2.3	344.4	61.5	19.2	14.3	0.6	95.7
	CO_2e (100-year)	205.9	59.3	113.1	7.2	385.6	93.4	26.9	51.3	3.3	174.9	25.9	7.5	14.3	0.9	48.6
	CO_2e (500-year)	101.2	24.8	113.1	10.3	249.3	45.9	11.2	51.3	4.7	113.1	12.7	3.1	14.2	1.3	31.4

Table B-5: Upstream Greenhouse Gas Inventory Results for Coal-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Coal)	CO_2	1.38E+01	1.39E+01	2.33E+03	0.00E+00	2.35E+03	6.26E+00	6.31E+00	1.06E+03	0.00E+00	1.07E+03	1.74E+00	1.75E+00	2.93E+02	0.00E+00	2.97E+02
	N_2O	5.54E-03	3.36E-04	3.99E-02	0.00E+00	4.58E-02	2.51E-03	1.53E-04	1.81E-02	0.00E+00	2.08E-02	6.98E-04	4.24E-05	5.03E-03	0.00E+00	5.77E-03
	CH_4	3.96E+00	7.57E-03	2.67E-02	0.00E+00	4.00E+00	1.80E+00	3.43E-03	1.21E-02	0.00E+00	1.81E+00	4.99E-01	9.54E-04	3.37E-03	0.00E+00	5.04E-01
	SF_6	1.77E-06	5.73E-11	0.00E+00	3.16E-04	3.18E-04	8.03E-07	2.60E-11	0.00E+00	1.43E-04	1.44E-04	2.23E-07	7.22E-12	0.00E+00	3.98E-05	4.00E-05
	CO_2e (20-year)	300.8	14.5	2,340.1	5.2	2,660.6	136.4	6.6	1,061.5	2.3	1,206.8	37.9	1.8	294.9	0.6	335.2
	CO_2e (100-year)	114.6	14.2	2,339.2	7.2	2,475.2	52.0	6.4	1,061.1	3.3	1,122.7	14.4	1.8	294.7	0.9	311.9
	CO_2e (500-year)	44.8	14.0	2,333.0	10.3	2,402.1	20.3	6.4	1,058.2	4.7	1,089.6	5.6	1.8	294.0	1.3	302.7
EXPC (Illinois No. 6 Coal)	CO_2	2.24E+01	1.18E+01	2.23E+03	0.00E+00	2.27E+03	1.02E+01	5.34E+00	1.01E+03	0.00E+00	1.03E+03	2.83E+00	1.48E+00	2.81E+02	0.00E+00	2.85E+02
	N_2O	3.52E-04	2.85E-04	3.77E-02	0.00E+00	3.83E-02	1.60E-04	1.29E-04	1.71E-02	0.00E+00	1.74E-02	4.44E-05	3.59E-05	4.75E-03	0.00E+00	4.83E-03
	CH_4	8.35E+00	6.42E-03	2.51E-02	0.00E+00	8.38E+00	3.79E+00	2.91E-03	1.14E-02	0.00E+00	3.80E+00	1.05E+00	8.08E-04	3.17E-03	0.00E+00	1.06E+00
	SF_6	4.42E-06	4.85E-11	6.11E-07	3.16E-04	3.21E-04	2.00E-06	2.20E-11	2.77E-07	1.43E-04	1.46E-04	5.57E-07	6.11E-12	7.70E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	623.7	12.3	2,243.5	5.2	2,884.7	282.9	5.6	1,017.6	2.3	1,308.5	78.6	1.6	282.7	0.6	363.5
	CO_2e (100-year)	231.4	12.0	2,242.7	7.2	2,493.3	104.9	5.5	1,017.3	3.3	1,130.9	29.2	1.5	282.6	0.9	314.1
	CO_2e (500-year)	86.1	11.9	2,236.8	10.3	2,345.0	39.0	5.4	1,014.6	4.7	1,063.7	10.8	1.5	281.8	1.3	295.5
IGCC (Illinois No. 6 Coal)	CO_2	1.98E+01	1.04E+01	1.89E+03	0.00E+00	1.92E+03	8.98E+00	4.72E+00	8.57E+02	0.00E+00	8.71E+02	2.49E+00	1.31E+00	2.38E+02	0.00E+00	2.42E+02
	N_2O	3.11E-04	2.52E-04	4.67E-05	0.00E+00	6.09E-04	1.41E-04	1.14E-04	2.12E-05	0.00E+00	2.76E-04	3.92E-05	3.17E-05	5.89E-06	0.00E+00	7.68E-05
	CH_4	7.37E+00	5.66E-03	9.58E-03	0.00E+00	7.38E+00	3.34E+00	2.57E-03	4.35E-03	0.00E+00	3.35E+00	9.28E-01	7.13E-04	1.21E-03	0.00E+00	9.30E-01
	SF_6	3.90E-06	4.28E-11	7.69E-07	3.16E-04	3.21E-04	1.77E-06	1.94E-11	3.49E-07	1.43E-04	1.45E-04	4.91E-07	5.40E-12	9.69E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	550.4	10.9	1,890.8	5.2	2,457.2	249.7	4.9	857.7	2.3	1,114.6	69.3	1.4	238.2	0.6	309.6
	CO_2e (100-year)	204.2	10.6	1,890.4	7.2	2,112.4	92.6	4.8	857.5	3.3	958.2	25.7	1.3	238.2	0.9	266.2
	CO_2e (500-year)	76.0	10.5	1,890.2	10.3	1,987.0	34.5	4.8	857.4	4.7	901.3	9.6	1.3	238.2	1.3	250.4
IGCC/ccs (Illinois No. 6 Coal)	CO_2	2.33E+01	1.22E+01	2.46E+02	0.00E+00	2.81E+02	1.06E+01	5.55E+00	1.11E+02	0.00E+00	1.28E+02	2.94E+00	1.54E+00	3.10E+01	0.00E+00	3.54E+01
	N_2O	3.66E-04	2.96E-04	9.13E-05	0.00E+00	7.54E-04	1.66E-04	1.34E-04	4.14E-05	0.00E+00	3.42E-04	4.61E-05	3.73E-05	1.15E-05	0.00E+00	9.50E-05
	CH_4	8.67E+00	6.67E-03	1.15E-02	0.00E+00	8.69E+00	3.93E+00	3.02E-03	5.20E-03	0.00E+00	3.94E+00	1.09E+00	8.40E-04	1.45E-03	0.00E+00	1.10E+00
	SF_6	4.59E-06	5.04E-11	8.72E-07	3.16E-04	3.21E-04	2.08E-06	2.29E-11	3.96E-07	1.43E-04	1.46E-04	5.78E-07	6.35E-12	1.10E-07	3.98E-05	4.05E-05
	CO_2e (20-year)	648.1	12.8	246.6	5.2	912.7	294.0	5.8	111.9	2.3	414.0	81.7	1.6	31.1	0.6	115.0
	CO_2e (100-year)	240.4	12.5	246.1	7.2	506.2	109.0	5.7	111.6	3.3	229.6	30.3	1.6	31.0	0.9	63.8
	CO_2e (500-year)	89.5	12.3	245.9	10.3	358.0	40.6	5.6	111.5	4.7	162.4	11.3	1.6	31.0	1.3	45.1

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
SCPC (Illinois No. 6 Coal)	CO_2	1.94E+01	1.02E+01	1.91E+03	0.00E+00	1.94E+03	8.78E+00	4.61E+00	8.66E+02	0.00E+00	8.79E+02	2.44E+00	1.28E+00	2.41E+02	0.00E+00	2.44E+02
	N_2O	3.04E-04	2.46E-04	6.99E-05	0.00E+00	6.20E-04	1.38E-04	1.12E-04	3.17E-05	0.00E+00	2.81E-04	3.83E-05	3.10E-05	8.81E-06	0.00E+00	7.81E-05
	CH_4	7.20E+00	5.53E-03	8.98E-03	0.00E+00	7.22E+00	3.27E+00	2.51E-03	4.07E-03	0.00E+00	3.27E+00	9.07E-01	6.97E-04	1.13E-03	0.00E+00	9.09E-01
	SF_6	3.81E-06	4.19E-11	8.26E-07	3.16E-04	3.21E-04	1.73E-06	1.90E-11	3.74E-07	1.43E-04	1.45E-04	4.80E-07	5.27E-12	1.04E-07	3.98E-05	4.04E-05
	CO_2e (20-year)	538.0	10.6	1,910.1	5.2	2,463.9	244.0	4.8	866.4	2.3	1,117.6	67.8	1.3	240.7	0.6	310.5
	CO_2e (100-year)	199.6	10.4	1,909.7	7.2	2,126.9	90.5	4.7	866.2	3.3	964.7	25.1	1.3	240.6	0.9	268.0
	CO_2e (500-year)	74.3	10.2	1,909.5	10.3	2,004.3	33.7	4.6	866.2	4.7	909.2	9.4	1.3	240.6	1.3	252.5
SCPC/ccs (Illinois No. 6 Coal)	CO_2	2.78E+01	1.46E+01	3.02E+02	0.00E+00	3.45E+02	1.26E+01	6.63E+00	1.37E+02	0.00E+00	1.56E+02	3.51E+00	1.84E+00	3.81E+01	0.00E+00	4.34E+01
	N_2O	4.37E-04	3.53E-04	1.07E-04	0.00E+00	8.97E-04	1.98E-04	1.60E-04	4.85E-05	0.00E+00	4.07E-04	5.50E-05	4.45E-05	1.35E-05	0.00E+00	1.13E-04
	CH_4	1.04E+01	7.95E-03	9.79E-03	0.00E+00	1.04E+01	4.69E+00	3.61E-03	4.44E-03	0.00E+00	4.70E+00	1.30E+00	1.00E-03	1.23E-03	0.00E+00	1.31E+00
	SF_6	5.48E-06	6.02E-11	8.34E-07	3.16E-04	3.22E-04	2.48E-06	2.73E-11	3.78E-07	1.43E-04	1.46E-04	6.90E-07	7.58E-12	1.05E-07	3.98E-05	4.06E-05
	CO_2e (20-year)	773.3	15.3	302.8	5.2	1,096.5	350.7	6.9	137.4	2.3	497.4	97.4	1.9	38.2	0.6	138.2
	CO_2e (100-year)	286.8	14.9	302.4	7.2	611.3	130.1	6.8	137.2	3.3	277.3	36.1	1.9	38.1	0.9	77.0
	CO_2e (500-year)	106.7	14.7	302.2	10.3	434.0	48.4	6.7	137.1	4.7	196.8	13.4	1.9	38.1	1.3	54.7

JISEA Joint Institute for Strategic Energy Analysis

Natural Gas and the Transformation of the U.S. Energy Sector: Electricity

Jeffrey Logan, Garvin Heath, and Jordan Macknick
National Renewable Energy Laboratory

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The Joint Institute for Strategic Energy Analysis is operated by the Alliance for Sustainable Energy, LLC, on behalf of the U.S. Department of Energy's National Renewable Energy Laboratory, the University of Colorado-Boulder, the Colorado School of Mines, the Colorado State University, the Massachusetts Institute of Technology, and Stanford University.

Technical Report
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The Joint Institute for Strategic Energy Analysis (JISEA) conducts interdisciplinary research—realized through teams drawn from the founding partners and a network of national and global affiliates—and provides objective and credible data, tools, and analysis to guide global energy investment and policy decisions. JISEA is focused on providing leading analysis; guiding decisions on energy, investment, and policy; and answering questions that enable a cost-effective transition to sustainable energy at significant speed and scale, while minimizing unintended impacts.

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Foreword

We are very pleased to present this work on natural gas and the transformation of the United States' power sector. The subject is both highly topical and divisive. Very few people saw the dramatic changes coming that are being witnessed in the U.S. natural gas sector. The critical role of unconventional gas—and specifically, shale gas—has been dramatic. The changes taking place in the U.S. natural gas sector go well beyond the boundaries of traditional energy-sector analysis. They touch on areas as diverse as foreign policy and industrial competitiveness.

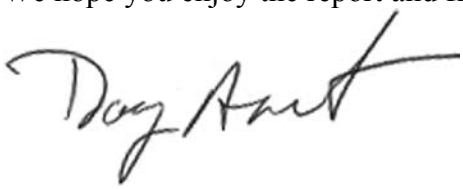
This makes the topic ripe for robust analytical work, which is the role of the Joint Institute for Strategic Energy Analysis (JISEA).

To help inform both the national and international dialogue on this subject, we have focused on a few key areas critical to decision makers. These issues include greenhouse gas emissions, regulatory interventions, water management, and the portfolio of generation in the power sector.

As part of our series of studies on the U.S. energy system, this body of work continues to elucidate details related to life cycle greenhouse gas emissions of shale gas relative to other options for power generation. It also contributes new analysis related to water and regulatory frameworks that are evolving apace. Additionally, we evaluate various pathways for the evolution of the electric sector given a range of options for natural gas, other technologies, and policy.

Although the four principal areas of focus in this report are closely interrelated, each has its own specific needs in terms of analysis, investment risk, and policy design. We have presented detailed consideration of each area, with further appended supporting material, to contribute to the ongoing and increasing national and international dialogue.

We hope you enjoy the report and find the results and discussion useful for your work.



Douglas J. Arent
Executive Director, JISEA

Preface

This report was developed with guidance from a cross-section of natural gas and electricity sector stakeholders. In 2011, JISEA convened a workshop with representatives from these organizations, some of whom also provided financial support for this work. That workshop resulted in identifying several key analytical issues for natural gas in the electric power sector that need to be addressed. Research, analysis, and writing were performed independently by the authors, with editorial oversight by JISEA. This study has been extensively peer reviewed. Findings, content, and conclusions of this study are the sole responsibility of the JISEA study team. JISEA provides objective information so that decision makers can make informed choices, but does not make its own policy recommendations.

Although the sponsoring organizations provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. The sponsoring organizations were not asked individually or collectively to endorse the report findings nor should any implied endorsement by the sponsoring organizations be assumed.

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This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise. These reviews serve to make this report as technically sound as possible, and they ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study scope.

We wish to thank the following individuals for their participation in the review of this report:

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Acronyms and Abbreviations

AGR	acid gas removal
bbl	barrels
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BLM	Bureau of Land Management
Btu	British thermal unit(s)
CBM	coal-bed methane
CCS	carbon capture and sequestration
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CES	clean energy standard (also known as clean electricity standard)
cf	cubic feet
CH_4	methane, the primary component of natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CSP	concentrating solar power
CWTs	centralized waste treatment facilities
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EUR	estimated ultimate recovery
FF	frac flowback (water)
g	gram(s)
GHG	greenhouse gas
GIS	geographic information system
GW	gigawatt(s)
hp	horsepower
hr	hour
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LCA	life cycle assessment
LNG	liquefied natural gas
MJ	megajoules
Mcf	thousand cubic feet
MMBtu	million British thermal unit(s)
NG-CC	natural gas combined-cycle
NG-CCS	natural gas generator with carbon capture and sequestration
NG-CT	natural gas combustion turbine
NGLs	natural gas liquids
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
POTWs	publicly owned treatment works
PW	produced water
PV	photovoltaic

RE	renewable energy (also known as renewable electricity)
RE Futures	Renewable Electricity Futures Study
ReEDS	Regional Energy Deployment System
SCC	Source Classification Code
scf	standard cubic foot
SEAB	Secretary of Energy Advisory Board Shale Gas Production
SolarDS	Solar Deployment System
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet
Tg	teragram(s), or million metric ton(s)
VOC	volatile organic compound
yr	year

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Executive Summary

Domestic natural gas production was largely stagnant from the mid-1970s until about 2005. Planning had been under way by the early 2000s to construct about 40 liquefied natural gas import terminals along the U.S. coasts to meet anticipated rising demand. However, beginning in the late 1990s, advances linking horizontal drilling techniques with hydraulic fracturing allowed drilling to proceed in shale and other formations at much lower cost. The result was a slow, steady increase in unconventional gas production.

As the technology improved and spread, domestic shale gas output began to increase rapidly, such that by 2008 commentators began to routinely speak of a shale gas "boom." Today, shale gas accounts for about 30% of total U.S. natural gas production—up from only 4% in 2005—helping to make the United States the largest producer of natural gas in the world by 2009. Within a decade, the question of how much more dependent the country would become on natural gas imports had been replaced by how much the U.S. gas supply will affect the economics and geopolitics of energy around the globe.

Although the long-term outcome of the shale gas revolution is far from decided, significant shifts are already apparent in U.S. power markets. In that context, low-price natural gas has had the greatest impact to date on generation by coal power plants. Since 2008, coal's share of annual generation has declined from 48% to 36% as of August 2012. This switch from coal to natural gas, combined with growth of renewable energy generation, has led to a reduction of carbon dioxide emissions in the U.S. power sector of about 300 million tons—equivalent to 13% of total power sector emissions in 2008.

It remains unclear, however, whether natural gas will continue to exert such a dramatic impact on the power sector and the overall U.S. economy. If natural gas prices continue to stay at, or near, historically low levels, then a self-correction in the shale gas boom may occur. Due to price concerns, some companies have shifted away from drilling for dry gas and instead are focusing on plays that provide natural gas liquids. The ongoing debate is about what price is needed for unconventional natural gas production to be more sustainable over the medium term. As an example, analysis from Range Resources indicates that New York Mercantile Exchange prices of $4–$6/MMBtu are needed at the vast majority of plays to generate adequate returns on investment.[1] Other factors—including "use it or lose it" lease terms, reserve filings with the Securities and Exchange Commission, and the amount of natural gas liquids that can be recovered—all play a role in continuing investment decisions. But, for now, natural gas markets are still widely acknowledged as oversupplied, and storage facilities held record high amounts of gas as of mid-2012.

Hydraulic fracturing has received negative attention in many parts of the country—especially those areas not accustomed to the oil and gas industry—due to real and perceived environmental and social concerns. Water use and contamination, air pollution, greenhouse gas (GHG) emissions, and truck traffic are among the concerns that have strained the social license to operate, and they have been the subject of multiple national and international reports and

[1] Specifically, a 12% internal rate of return (IRR). The reference to this analysis appears in Ventura, J., 2012. "Uncovering Tomorrow's Energy Today," presentation at the Goldman Sachs Global Energy Conference 2012. 10 January 2012. Slide 11. Accessed 9 June 2012.

continued dialogue. Field practices associated with unconventional natural gas production have evolved rapidly in some regions, either from new regulatory requirements or voluntary company practices. These field practices are still evolving, can be uneven across regions, and are sometimes controversial. At the same time, consolidation within the industry is shifting production from smaller to larger companies.

The Joint Institute for Strategic Energy Analysis (JISEA) designed this study to address four related key questions, which are a subset from the wider dialogue on natural gas:

1. What are the life cycle greenhouse gas (GHG) emissions associated with shale gas compared to conventional natural gas and other fuels used to generate electricity?
2. What are the existing legal and regulatory frameworks governing unconventional gas development at federal, state, and local levels, and how are they changing in response to the rapid industry growth and public concerns?
3. How are natural gas production companies changing their water-related practices?
4. How might demand for natural gas in the electric sector respond to a variety of policy and technology developments over the next 20 to 40 years?

Major Findings

Although the questions analyzed in this report are interlinked to a certain extent, they have specific requirements in terms of analysis methodologies and associated stakeholders. The key findings are presented very briefly as follows:

- **Greenhouse gas emissions:** Based on analysis of more than 16,000 sources of air-pollutant emissions reported in a state inventory of upstream and midstream natural gas industry, life cycle greenhouse gas emissions associated with electricity generated from Barnett Shale gas extracted in 2009 were found to be very similar to conventional natural gas and less than half those of coal-fired electricity generation.

- **Regulatory trends:** The legal and regulatory frameworks governing shale gas development are changing in response to public concerns and rapid industry changes, particularly in areas that have limited experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with increasing unconventional natural gas production.

- **Water management:** Many regions evaluated in this study are making greater use of innovative water management practices to limit real and perceived risks. However, a lack of reliable, publicly available water usage and management data—such as total water withdrawals, total wells drilled, water-recycling techniques, and wastewater management practices—currently hinders efforts to develop appropriately flexible and adaptive best management practices. Recent studies have documented a number of management practices related to the chemical makeup of fracking fluids, impacts on local freshwater, and on-site wastewater management that may be appropriate in many locations.

However, to date, no public studies have been published on cost-benefit, risk-mitigation potential, or the transferability of practices from one shale play to another.

- **Electric power futures:** A number of different future electric power scenarios were analyzed to evaluate both the implications of shale gas development and use, and various policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gas emissions, and variations in natural gas supply and demand. We find that natural gas use for power generation grows strongly in most scenarios.

Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Using Air-Quality Inventory Data

A national debate over life cycle GHG emissions[2] from shale natural gas erupted in 2011 after a study was released stating that shale gas had equivalent or even greater GHG emissions than coal.[3] Since then, a number of other published, peer-reviewed studies have included contrary findings,[4] although data limitations and methodological variability make conclusive statements problematic about the "real" GHG emission profile.

For Chapter 1, the study team conducted original research on life cycle GHG emissions associated with natural gas production in the Barnett Shale play in Texas. This estimate leverages high-resolution empirical data to a greater extent than previous assessments. The data sources and approach used in this study differ significantly from previous efforts, providing an estimate valuable for its complementary methodological approach to the literature.

The authors used inventories from 2009 that tracked emissions of regulated air pollutants by the natural gas industry in the Barnett Shale play. The Texas Commission on Environmental Quality (TCEQ) collected and screened these inventories. These data cover the characteristics and volatile organic compound (VOC) emissions of more than 16,000 individual sources in shale gas production and processing. Translating estimated emissions of VOCs into estimates of methane and carbon dioxide emissions was accomplished through the novel compilation of spatially heterogeneous gas composition analyses.

Major findings from this analysis of life cycle GHG emissions include:

- Electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 has life cycle GHG emissions ranging between 420 and 510 grams carbon dioxide-equivalent emissions per kilowatt-hour (g

[2] GHG emissions considered within a life cycle assessment (LCA) include those from the "fuel cycle" of natural gas, which includes activities from well drilling and completion, through production, processing, and transport to the power plant, as well as from the life cycle of the power plant, which includes construction and decommissioning of the power plant and combustion of the fuel. Results are normalized per unit of electricity generated (kWh). See Figure 7 within Chapter 1 and the surrounding text for further description of the scope of this LCA.
[3] Howarth, R. W., R. Santoro, and A. Ingraffea. 2011. "Methane and the greenhouse gas footprint of natural gas from shale formations." *Climatic Change Letters*, DOI: 10.1007/s10584-011-0061-5 (http://www.springerlink.com/content/e384226wr4160653/fulltext.pdf).
[4] These studies include Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011.

CO_2e/kWh) generated, depending on assumed lifetime production of a well, with a central estimate of about 440 g CO_2e/kWh—similar to levels reported in the literature from conventional natural gas and less than half that typical for coal-fired electricity generation (Figure 1).[5] Comparisons to conventional natural gas and coal are achieved through harmonization of 200 published estimates of life cycle GHG emissions for those two technologies.[6] Harmonization is a meta-analytical process that makes consistent the assumptions and methods between LCAs.

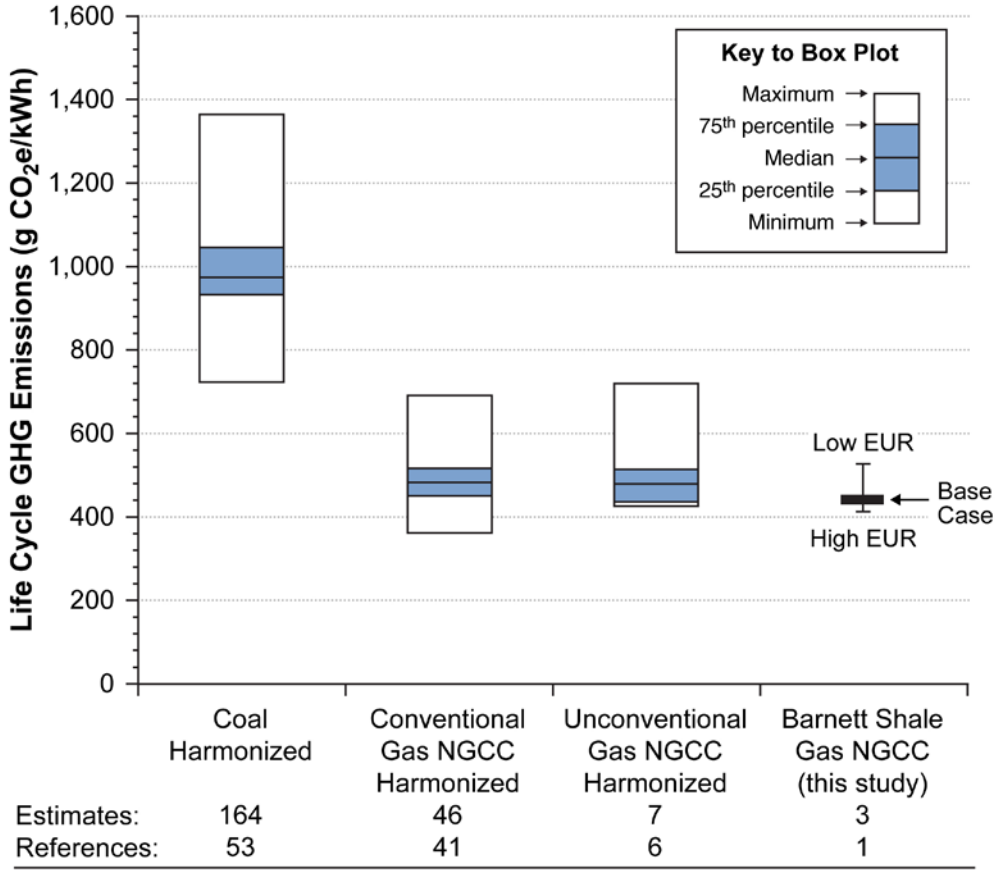

Figure 1. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization.

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

[5] The results reported here do not include emissions associated with liquids unloading, a process that the natural gas industry recently reported as applicable to both conventional *and* unconventional wells, but without direct evidence for the Barnett Shale play. (See: Shires and Lev-On (2012).)
However, inclusion of these emissions would not qualitatively change our findings.

[6] See Whitaker et al. 2011 and O'Donoughue et al. 2012 for systematic review and harmonization of published estimates of life cycle GHG emissions from coal-fired and conventional natural gas-fired electricity generation, respectively.

- An estimated 7% to 15% of life cycle GHG emissions from electricity generation (mean = 9%) are from methane emissions throughout the fuel cycle of Barnett Shale gas (well pre-production activities through transmission), mostly from venting during completion and workover, and from the natural gas transmission pipeline network.
- GHG emissions result from many sources throughout the production and use of natural gas. Based on our analysis, more than half can be characterized as sources with potentially controllable leakage—for instance, from tanks or vents**.** Another 20% are combustion sources, which also have some emission control opportunities. Remaining sources, called fugitive emissions, are more challenging to control because of their dispersed nature.
- An estimated 1.5% of Barnett Shale produced gas is emitted to the atmosphere before reaching the power plant, much of which is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas and average assumed lifetime production of a well, this equates to a central estimate of leakage rate across the life cycle of 1.3% methane volume per volume of natural gas processed.
- Chemical composition of produced gas varies considerably within the Barnett Shale area such that at the county level, estimates of GHG emissions differ significantly from those based on composition averaged at a higher spatial resolution (play or nation). Variability in gas composition has implications for the understanding of emission sources and the design of regulatory emission control strategies.

A Changing Regulatory Framework for Unconventional Gas Production

Chapter 2 examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development. Specifically, it focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well-construction standards, “green” or “reduced emission” completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities, and the efforts by some local governments in key gas-producing states to limit—and, in some cases, ban—unconventional gas development. Major findings include the following:

- There is a trend toward more regulation at all levels of governance, but there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks to industry and the public of regulatory fragmentation—including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information among regulators at all levels of government and across jurisdictions, as well as increased transparency in the form of publicly available data from industry, would help address regulatory fragmentation and inform regulatory development tailored to specific geographic and geologic characteristics.
- Compliance monitoring and enforcement varies across states, with significant implications for the efficacy of regulations, as well as public confidence. Increased public disclosure of voluntary information—as well as public disclosure of violations,

enforcement actions, and company compliance—would increase transparency, offer opportunities to highlight the compliance records of leading companies who have demonstrated a commitment to safe natural gas production, and help address public concerns.

- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. There is an evolving portfolio of recommended practices emerging from across the stakeholder community; these practices can complement and supplement regulations.
- The varied state and local approaches to regulation can provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and compliance and enforcement. Regulators might consider adopting performance-based standards, rather than freezing today's "best management practices" into prescriptive rules that could become outdated.

Management Practices in Shale Gas Production: Focus on Water

Chapter 3 addresses current water usage and water management practices at shale gas development sites and discusses risks to water availability and quality. We evaluated publicly available water usage data from six shale plays throughout the United States. When data were available, we conducted statistical analyses from a randomized sample of wells in each play to gauge current estimates of water usage per well. In addition, data were collected on current wastewater management techniques and volumes associated with managing produced water from wells along with the returned fracking fluids. Lastly, in addition to analyzing current industry practices, we evaluated how water usage, well number, and water management techniques have evolved over time, indicating that water risk and management issues in the future may differ from historical issues. Natural gas exploration and production has significant spatial variability in community and environmental issues, current practices, and regulations. Therefore, JISEA is also publishing the water-related results of this study in a web-based GIS format.

The three primary water impact risks are: regional resource depletion due to use of fresh water during hydraulic fracturing, surface water degradation, and groundwater degradation. Impact risks to water resources vary geographically based on three considerations: 1) where the water comes from, 2) what water use and management practices are followed on site for hydraulic fracturing, and 3) how and where produced water and frac flowback water are treated and/or disposed.

Major findings from this analysis of water impacts include the following:

- Risks to regional freshwater depletion depend on a variety of factors, including water use per well, total number of wells, water recycling rates, and regional water availability. Analysis of use data for four of the six regions from 2007 to 2011 indicated average water use per well ranges from 1.1 to 4.8 million gallons, with a multi-region average of 3.3 million gallons. The total magnitude of water usage depends on the number of wells drilled, which has increased in most regions from 2007 to 2011. In the Eagle Ford play, for example, gas wells increased from 67 in 2009 to 550 in 2011. Total freshwater usage depends on water recycling rates, which may vary greatly depending on location. In

2011, the highest rates of recycling were reported in Pennsylvania, where 37% of produced water and 55% of frac flowback water were recycled, representing nearly 200,000 gallons per well, or 4% of average water use per well in Pennsylvania. Total impacts on regional freshwater resources can be evaluated by comparing total freshwater uses with estimates of regional freshwater availability.

- Wastewater management practices vary regionally and show different trends from 2008 to 2011. In Pennsylvania, 80% of produced water and 54% of frac flowback water was treated through surface water discharge in 2008, whereas in 2011, less than 1% of produced water and frac flowback was treated through surface water discharge. In 2011, centralized disposal facilities and recycling are the primary wastewater management methods, accounting for 80% of produced water volumes and 99% of frac flowback volumes. In Colorado, surface water discharge of both produced water and frac flowback volumes has increased from 2% in 2008 to 11% in 2011. Management of produced water and frac flowback through onsite injection pits and evaporation ponds have remained the dominant practices from 2008 to 2011, representing 72% and 58%, respectively. Treatment at a centralized disposal facility has increased from 26% to 31% from 2008 to 2011. The management and transport of produced water and frac flowback water is considered to be the stage at which spills and leaks are most likely.
- A lack of reliable, publicly available water usage and management data hinders comprehensive analyses of water risks**.** Data are not publicly available for total water withdrawals, total gas wells drilled, flowback volume per well, water recycling techniques, wastewater management, and other management practices for many regions. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; however, further efforts would be beneficial.
- A variety of best management practices are currently being employed in different regions, but there is industry uncertainty over transferability, cost-effectiveness, and risk mitigation potential. Recent studies have documented a number of water-related management practices related to the chemical makeup of fracking fluids (disclosure of additives, minimizing or switching to more benign additives, baseline water quality testing), the impacts on local freshwater (measuring and reporting of volumes, water recycling, use of non-potable or non-water sources), and onsite wastewater management techniques (use of closed-loop drilling systems, elimination of flowback and freshwater mixing in open impoundments, use of protective liners at pad sites) that may be appropriate in many locations. However, to date, there are no publicly available studies that have performed cost-benefit analyses, evaluated the risk-mitigation potential of each strategy, or analyzed practices that could be transferred from one shale play to another.

Modeling U.S. Electric Power Futures Given Shale Gas Dynamics

In Chapter 4, the study evaluates different electric power scenarios that are influenced by natural gas availability and price, as well as other key policy, regulatory, and technology factors. Many of the scenarios examine sensitivities for the estimated ultimate recovery (EUR) of gas fields. High-EUR corresponds to more abundant and inexpensive natural gas compared to Low-EUR.

Major findings from the electric sector analysis include the following:

- Natural gas demand by the power sector would grow rapidly—more than doubling from the 2010 level by 2050—in the Reference, or baseline, scenario.[7] Figure 2 illustrates the range of natural gas power generation in all scenarios. The main Reference scenario suggests that natural gas would replace coal as the predominant fuel for electricity generation. Attributes of this baseline scenario include rising power demand, stable greenhouse gas emissions, and slowly rising electricity prices that reflect natural gas availability and prices. By 2050, in the Reference scenario, gas could represent from 28% to 38% of power-sector generation compared to the 2010 portion of 20%.
- In a coal retirement scenario, natural gas, and wind to a lesser extent, replaces coal-based generation. Our modeling results indicate no impact on power sector reliability from 80 GW of coal retirements by 2025 on an aggregate scale, although additional detailed dispatch modeling is needed to evaluate localized impacts. National average retail electricity prices in the retirement scenario increase by less than 2% in 2030 compared to the baseline.
- Under a clean energy standard (CES) scenario, U.S. power sector carbon dioxide emissions would decrease by 90% between 2010 and 2050, with a corresponding 6%–12% increase in average retail electricity prices, including transmission build-out that ranges from 3 to 6 times more than the Reference scenario (measured in million MW-miles). Among the CES sensitivity scenarios, large quantities of variable renewable energy and flexible gas generation work synergistically to maintain system reliability requirements.

[7] A Reference scenario serves as a point of comparison with other alternative scenarios. The Reference assumes a fairly static view of the future, so it, and all alternative scenarios, should not be considered forecasts or predictions of the future.

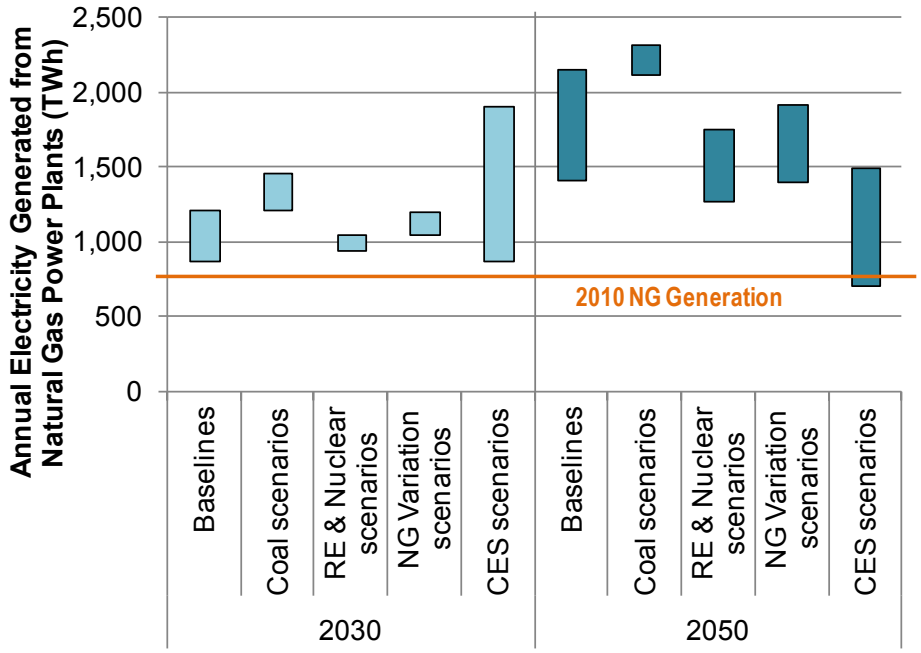

Figure 2. Range of electricity generated from natural gas plants in the scenario analysis

- Advances in generation technologies can have a significant impact on estimated carbon emissions, electricity diversity, and prices. For example, nuclear capital costs would need to decline by half, while gas prices remain relatively high (as simulated in the low-EUR assumption), for the nuclear generating option to compete economically with other options. Wind and solar electricity could more than double by 2050 compared to the Reference scenario with continued improvements in the cost and performance of these technologies. Likewise, continued improvements in production techniques for unconventional natural gas production could enable natural gas to continue to grow market share.
- We consider a range of potential incremental costs associated with operating practices that could better address some of the public concerns in the production of unconventional natural gas. Some of these options include recycling larger amounts of frac flowback water, reducing methane releases to the atmosphere, setting well locations further from potentially sensitive communities, and assuring consistent use of best practices or regulations in well drilling and completions. Sensitivities in incremental costs were evaluated from $0.50/MMBtu to $2/MMBtu. For example, additional costs of $1/MMBtu associated with some or all of these several dozen operating practices would lead to a 17% reduction in gas use for power generation by 2050 compared to the Reference scenario; however, gas-fired generation still more than doubles from the 2010 level.
- A “dash-to-gas” scenario, where other sectors of the economy increase natural gas demand by 12 billion cubic feet per day by 2030, would likely result in higher domestic gas prices and lead to a roughly 20% reduction in power sector natural gas use by 2050 compared to the Reference scenario in that year, but still nearly twice the level used in 2010. Additional research is needed to understand how natural gas prices respond to rising demand in the new natural gas environment.

The rapid expansion of shale gas has created dynamic opportunities and challenges in the U.S. energy sector. How long the ascendancy of natural gas in the electric sector will last will be a function of a wide variety of market and policy factors. The story of unconventional gas is evolving rapidly, and in some cases, unexpectedly. Robust and up-to-date analysis will remain critical to informing the key decisions that must be made by all types of stakeholders in the energy and environmental arenas.

Introduction

This report addresses several aspects of the changing context of natural gas in the U.S. electric power sector. Increasingly plentiful and affordable natural gas has catalyzed major changes in U.S. power generation and has helped to boost U.S. economic recovery. Increased substitution of natural gas for coal in power generation has also cut U.S. GHG emissions. However, processes to produce natural gas—shale gas in particular—have also elevated environmental and safety concerns in certain regions of the country. The rapid rise of natural gas is also beginning to drive more thought on longer-term energy policy issues such as the appropriate level of generation diversity (given the history of volatile prices for natural gas), and trajectories of natural gas use that will still allow GHG mitigation sufficient to address the climate challenge.

This report is intended to help inform those energy policy and investment discussions. This chapter first outlines the current dynamics of natural gas in the power sector and then describes how the remainder of the report addresses selected challenges and opportunities in the use of natural gas to generate electricity.

Natural gas supply and demand are transforming the energy marketplace. Natural gas prices have been relatively volatile over the past 40 years, at least compared to coal (see Figure 3). Today, advances in unconventional gas production, which include a host of technologies and processes beyond horizontal drilling and hydraulic fracturing,[8] have enabled a new market outlook. Shale production grew from less than 3 billion cubic feet per day (bcf/d) in 2006 to about 20 bcf/d by mid-2012.[9] Without this expansion, natural gas prices might be significantly higher because most other sources of domestic natural gas production are in decline.

Given the low-price outlook, many new potential uses for natural gas outside of power generation are being considered and developed—including the export of LNG, the use of compressed natural gas in vehicles, the construction of ethylene plants and other chemical facilities that use natural gas and associated products as a feedstock, and, potentially, investment in gas-to-liquids facilities that convert natural gas into synthetic petroleum products (i.e., diesel) that can be used as a transportation fuel in existing infrastructure. Efforts to further develop the latter may become particularly strong if the price gap shown in Figure 3 remains.

[8] For a description of this technological progress, see Seto (2011).
[9] In 2011, the U.S. power sector consumed about 22 bcf/d and the entire economy consumed about 67 bcf/d (EIA 2012b).

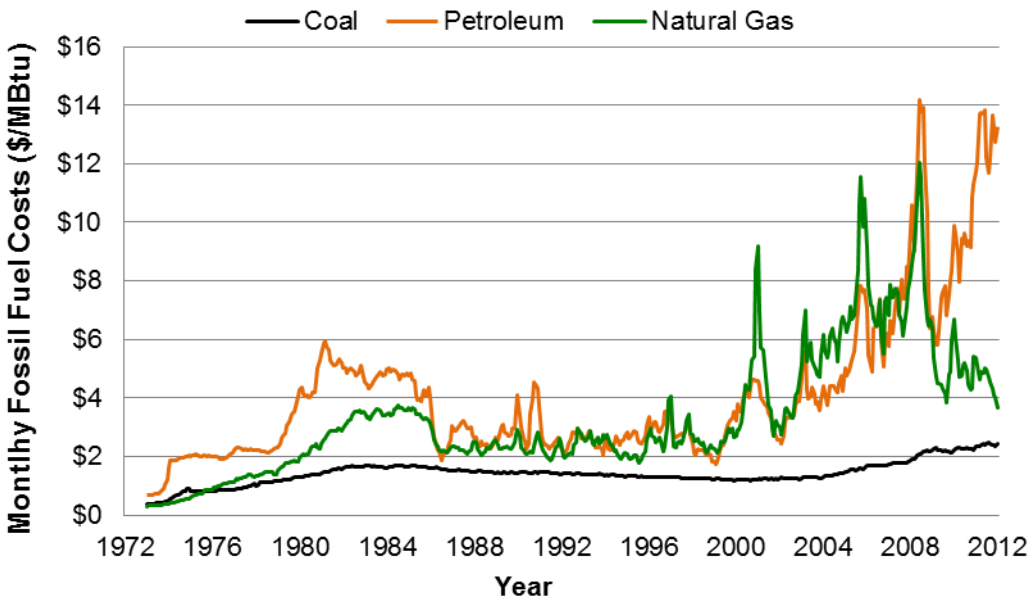

Figure 3. Volatility in fossil fuel costs for power generators

Source: EIA, "Monthly Energy Review," April 27, 2012.

However, given the current low-price environment, many producers have scaled back their plans to drill for dry natural gas, even as they accelerate drilling for wet natural gas (whose natural gas liquids are sold at prices comparable to petroleum products). These cutbacks have contributed to the recent increase in Henry Hub prices, from a low of $1.90/MMBtu in early 2012 to more than $3.60/MMBtu by November 2012. On the other hand, the number of rigs actively developing natural gas has declined sharply since 2009 while production continues to expand, indicating that producers are getting more output with less input (Ebinger et al. 2012). Where prices go next will be influenced by potential new sources of demand noted above, and by supply-side issues, including continued technology improvement, efforts to better protect the environment, and regulatory requirements.

Coal-generated electricity is rapidly declining. Dramatic changes are occurring in the U.S. electric power sector. These changes include a steep reduction in the portion of electric power coming from coal combustion, and a corresponding increase in that provided by natural gas and (to a lesser extent) renewable sources, especially wind power (see Figure 4). Eastern and southern regions are generally experiencing the most rapid shift in generation mix (see Appendix A for more detail). Coal's contribution to total annual U.S. power generation has fallen more rapidly over the past four years than in any time in the history of data collection—from roughly 48% of U.S. generation in 2008 to 36% as of August 2012. Had coal generation remained at the 2008 level, the U.S. power sector would be emitting roughly 300 million tons of additional CO_2 each year.[10]

[10] This is a "burner tip" analysis only and does not consider the full life cycle GHG emissions of coal or natural gas. Data for 2012 are based on a rolling 12-month sum ending in August. The carbon mitigation calculation is based on a 440 TWh reduction in coal generation and corresponding increase in natural gas combined-cycle generation of 310 TWh. Growth in certain renewable generation sources and a reduction in power demand make up the remaining

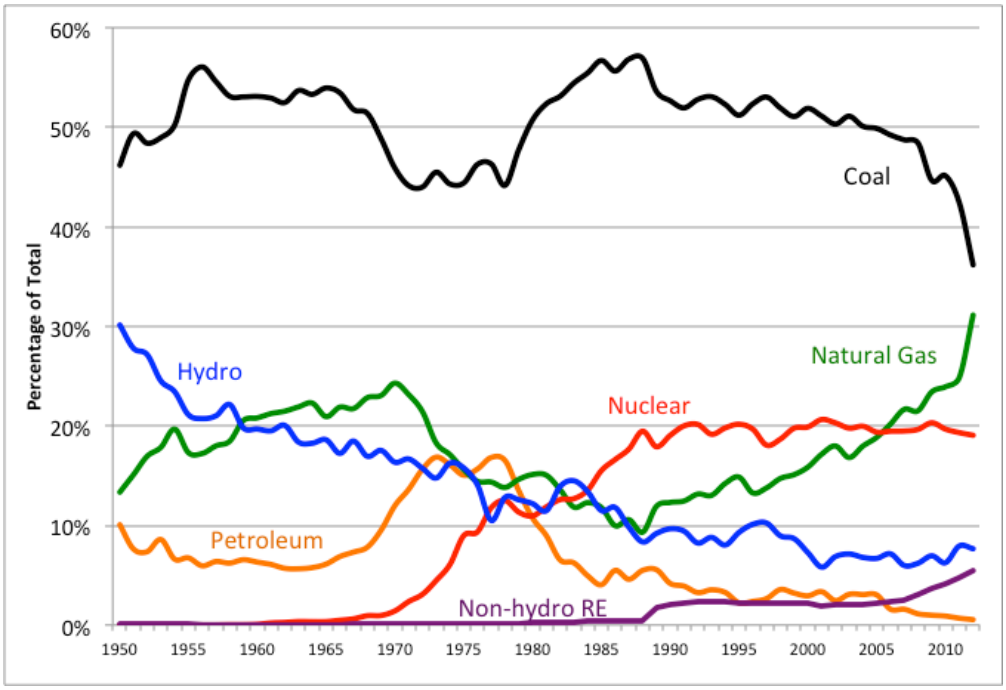

Figure 4. Coal-fired electricity generation is declining rapidly as the use of natural gas and renewable energy expand

Source: EIA, "Annual Energy Review," September 27, 2012; EIA "Electric Power Monthly," October 31, 2012. Data for 2012 includes generation through August only.

The primary drivers of these changes include low-priced natural gas resulting from rapidly growing shale gas production, an unusually warm 2011–2012 winter throughout much of the contiguous United States,[11] and the expectation that EPA will issue new or revised power plant regulations to further protect the environment.[12] It remains to be seen whether this trend of declining coal generation continues, stabilizes, or reverses itself.[13]

Hydraulic fracturing presents opportunities and challenges that are in the headlines daily. These opportunities include additional U.S. jobs, increased economic activity, potentially greater energy diversity (particularly in the transportation sector), and less reliance on imported fossil fuels. Challenges largely center on environmental and social concerns associated with shale gas

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difference. See EIA Electric Power Monthly (October 2012) for more detail. Chapter 1 of this report addresses the issue of life cycle GHG emissions for various electric generating technologies.

[11] The U.S. Department of Energy reported that the number of heating degree days in the first quarter of 2012 were at the lowest level since record keeping began in 1895 (EIA 2012a).

[12] These rules include the Cross-States Air Pollution Rule (recently vacated, but backstopped by somewhat less restrictive requirements), the Mercury and Air Toxics Standard, the Clean Water Act Section 316(b) Water Intake Structures, and the Coal Combustion Residual requirements. Numerous studies attempt to estimate the potential impacts of some or all of these rules after they take effect (see CRS 2011; CERA 2011; and Credit Suisse 2010).

[13] In a May 22, 2012 presentation to investors, for example, ArchCoal stated that half of the coal generation recently lost to low-cost natural gas could be recovered when gas prices rise back above $3/MMBtu (Slone 2012). AEP also noted in an October 24, 2012 news story that it had seen some fuel switching from natural gas back to coal due to rising natural gas prices (Reuters, 2012).

production, especially through hydraulic fracturing.[14] These concerns are acute in some states and increasingly on the docket for federal regulators in several agencies. Current federal regulations to protect surface and underground water resources are less onerous for hydraulically fractured gas production than they are for conventional oil and gas drilling, although many states are passing or updating rules quickly as drilling expands (see Chapter 2, UT 2012, Zoback 2010). Companies are also making greater voluntary efforts to ensure the likelihood that air, water, land, and other resources are protected—at least compared to the early days of hydraulic fracturing—although these efforts are still not practiced universally (see Chapters 2 and 3).

A more general concern for policy makers centers on the role of natural gas versus other sources of electricity in the future: low-priced natural gas could disrupt the development of advanced nuclear or renewable energy technologies, for example, and delay the date when they are cost competitive with traditional energy options. If natural gas prices rose substantially after the power sector had evolved to become more reliant on that fuel, the economy could be vulnerable to an expensive and "locked-in" power sector.

This report focuses on four topics. First, Chapter 1 addresses the full life cycle GHG emissions of shale gas compared to other power generation options. Questions about these "cradle-to-grave" emissions began to appear in 2011 with several reports claiming that shale gas had life cycle GHG emissions as high as, or higher than, coal.[15] Controversy remains over how much methane is released to the atmosphere during the process of producing natural gas, in general, and shale gas, in particular. Chapter 1 uses a new approach to advance the state of knowledge about the life cycle GHG emissions from shale gas based on analysis of highly resolved inventories of air pollutant emissions completely independent of the data sources used in previous research.

Second, Chapter 2 surveys the legal and regulatory trends associated with shale gas production at both the federal and state level. Although federal agencies are taking an active role in ensuring that shale gas is produced safely, Congress has imposed some limitations on what agencies can regulate. The state role in regulating unconventional natural gas production is more pronounced and varied. Chapter 2 summarizes trends in regulatory action at six major unconventional gas plays/basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming.

Third, Chapter 3 assesses environmental and community risks associated with unconventional natural gas production in the same six regions identified in Chapter 2. It focuses particularly on water issues and company practices that impact water. Public concern over environmental and safety issues has been severe enough in some areas to delay or halt plans to develop unconventional production.

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[14] See, for example, SEAB (2011a and 2011b), MIT (2011), and UT (2012). There is some confusion surrounding hydraulic fracturing and the potential for environmental impact. Those in industry typically use the term in a focused way, referring to the brief period of time that a high-pressure mixture of water, sand, and additives is being injected, and later, partially removed (flowback). The general public often takes a broader view and labels the entire process of producing unconventional gas or oil as hydraulic fracturing. Significant controversy results from the difference in semantics.

[15] See Lustgarten (2011) and Howarth et al. (2011), for example.

A GIS tool was developed to help evaluate:

- Water availability, use, and cost information
- Water flowback and produced water
- Best current practices for management.

Current practices and regulatory oversight need to be evaluated at a deeper level before the overall goal of determining the costs of acceptable practices can be achieved. Chapter 3 describes a comprehensive approach to evaluating risks and following practices so as to support greater public confidence.

In Chapter 4, we report on different U.S. electric power futures based on a variety of potential developments in technology, environmental protection, GHG mitigation, social license to operate, and gas demand outside the power sector. We use the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) to simulate the impact of these different futures, and benchmark information from Chapters 1–3 in the scenario analysis. Chapter 5 synthesizes findings and summarizes potential follow-on research.

1 Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Used to Generate Electricity

1.1 Introduction

According to the 2010 U.S. Greenhouse Gas Emissions Inventory (EPA 2012a), the natural gas industry[16] represents nearly a third of total methane emissions in the United States in 2010—the largest single category—and is also the fourth largest category of CO_2 emissions.[17] EPA, which produces the U.S. GHG inventory, significantly increased estimates of methane emissions from the natural gas industry for the 2009 inventory year, resulting from a change in its assessment of emissions from four activities, the most important of which were: well venting from liquids unloading (attributed only to conventional[18] wells by EPA); gas well venting during completions; and gas well venting during well workovers[19] (EPA 2011). The sum of these changes more than doubled the estimate of methane emissions from natural gas systems from the 2009 inventory compared to the 2008 inventory. EPA acknowledges what is well understood: the estimates of GHG emissions from the natural gas sector are highly uncertain, with a critical lack of empirical data to support GHG emission assessments (EPA 2011). This is especially acute for production of unconventional gas resources. Data gathering to support re-assessment of the EPA's U.S. GHG inventory and potential regulations is under way.

An emerging literature has attempted to estimate GHG emissions from unconventional natural gas production, based on the limited available information. Measurement of GHGs in the atmosphere, if they could be reliably attributed to specific sources, would be the ideal methodological approach. However, such measurements are expensive, attribution is challenging, and only one pilot study has been published to date based on measurements in one gas field—which, since the time of measurement, has implemented new practices based on changing state regulations (Petron et al. 2012). The state of the practice employs engineering-based modeling, based on as much empirical information as is possible to assemble.

Much of this emerging literature is guided by the methods of life cycle assessment (LCA), which in this context aims to estimate all GHG emissions attributable to natural gas used for a particular function: electricity, transportation, or primary energy content (e.g., heat). Attributable emissions are those from any activity in the process chain of producing the natural gas—from exploration and well pad preparation to drilling and completion—processing it to pipeline quality, transporting it to the location of end use, and combustion. In addition, the construction, operation and maintenance, and end-of-life decommissioning of the end-use technology are also considered.

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[16] For purposes of the GHG Inventory, the natural gas industry includes exploration, production, processing, transmission, storage, and distribution of natural gas to the end user (EPA 2011).

[17] In 2010, total U.S. GHG emissions have been estimated as 6,822 Tg or million metric tons CO_2e (EPA 2012a). Of this total, 84% were from CO_2, with most of the remaining (10%) from methane. Direct emission from the combustion of fuels, including natural gas, for electricity generation contributes 2,258 Tg CO_2, or 33% of total GHG emissions. Natural gas systems contribute 247 Tg of CO_2e, or 3.6% of total emissions, 87% from emissions of methane.

[18] Defined as any non-stimulated well. This report follows EPA (2011) in recognizing "that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate."

[19] The frequency of which has since been reduced from 10% of wells per year to 1% of wells per year (EPA 2012b).

LCAs are typically performed to compare the results from one system to another.[20] The focus of this chapter is to advance understanding of GHG emissions from the production and use of shale gas in the context of the electric power sector as compared to generation of electricity from conventionally produced natural gas. Natural gas once processed for pipeline transmission to end-use customers is a homogenous product, undifferentiated by source. End-use combustion of the natural gas has, by far, the largest contribution to life cycle GHG emissions (as is true for any fossil-fueled combustion technology); but is not a point of differentiation between conventional and unconventional natural gas. Therefore, this study focuses on the activities associated with production of natural gas because they are the points of potential differentiation between unconventional and conventional natural gas.

We additionally focus on emissions from natural gas processing, given current regulatory and scientific attention to emissions from the natural gas industry and opportunity provided by the unique data sources employed in this study. Furthermore, we rely on the multitude of previously published LCAs of conventionally produced natural gas, updated for recent changes in understanding (EPA 2011; EPA 2012b) and harmonized for methodological inconsistency, as embodied in our publication (O'Donoughue et al. 2012), for comparison to the results of this study. We also compare our results to those for coal-fired electricity generation based on a systematic review and harmonization of that LCA literature, because coal has been the largest source for electricity in the United States over the last 50-plus years (Whitaker et al. 2012).

Prior research comparing life cycle GHG emissions of electricity generated from shale gas to conventional gas has been inconclusive and remains highly uncertain. Both the magnitude and direction of difference reported in these publications vary (Howarth et al. 2011; Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011). This is despite their reliance on very similar data sources (mostly EPA's GHG emission inventory and supporting documentation). Uncertainty in the underlying data sources drives the uncertainty in published results. Furthermore, inconsistent approaches to data use and other assumptions thwart direct comparison of the results of these studies and the development of collective understanding.

Separately, the authors have examined this literature using a meta-analytical technique called harmonization that clarifies the collective results of this emerging literature by adjustment to more consistent methods and assumptions (Heath et al. 2012). In that publication, the authors elucidate differences between previously published estimates of life cycle GHG emissions from combustion of shale gas for power production and key sensitivities identified in this literature. Key sensitivities include EUR and lifetime (years) of wells; emissions and emissions reduction practices from well completion and workover; and emissions and emission reduction practices from well liquids unloading, all of which vary from basin to basin and from operator to operator. A key conclusion from the assessment of previous estimates of unconventional gas life cycle GHG emissions is that given current uncertainties, it is not possible to discern with a high level of confidence whether more GHGs are emitted from the life cycle of shale gas or conventional gas used for electricity generation.

[20] For interested readers, many texts describe LCA principles and methods, such as Horne et al. (2009) and Vigon et al. (1993).

In this chapter, we present results from a new method of estimating life cycle GHG emissions from shale gas that takes advantage of unusually detailed and rarely produced empirical data specific to a shale gas play and year. Our empirical data sources and approach differ significantly from previous efforts. Broadly, we use the methods of air quality engineering, life cycle assessment, and energy analysis to estimate GHG emissions attributable to the generation of electricity from shale gas produced from the Barnett Shale play in Texas in 2009, the latest year with available data. There are several unique aspects of this research as compared to previous natural gas life cycle assessments:

- Highly resolved estimates of GHG emissions from shale gas production and processing developed at site (facility) and source (equipment and practices) levels.
- Use of industry-supplied and regulator quality-assured data regarding equipment, practices, and emissions developed with very high participation rates.
- Development of a publicly available data set of county-level, extended gas composition analyses of produced (raw) gas demonstrating wide variability of methane and VOC content within the Barnett Shale formation.

It is critical to note that the new results reported here are not necessarily applicable to other plays or years. However, they are discussed in the context of other published literature, where the broad outlines of consistency found within this literature increases confidence in the results, albeit still hampered by many areas of uncertainty remaining to be addressed through further research.

Commercial production of shale gas began in the 1980s, starting in the Barnett Shale play in Texas. The Barnett Shale play continues to be a large source of gas, estimated at more than 6% of total U.S. natural gas production (Skone and James 2010). Data on production and processing activities in this 22-county[21] area (Figure 5) are some of the best available for any unconventional gas formation in the United States. For these reasons, the focus of the analysis of this chapter is shale gas produced from the Barnett Shale formation. As illustrated in Figure 5, the highest production occurred within the Dallas-Ft. Worth metropolitan area, which is in non-attainment for the National Ambient Air Quality Standard for ozone (and other pollutants).

[21] The Barnett Shale is sometimes referred to as consisting of 23 or 24 counties. However, this analysis focuses on the 22 counties with non-zero gas production for 2009 (TRRC 2012).

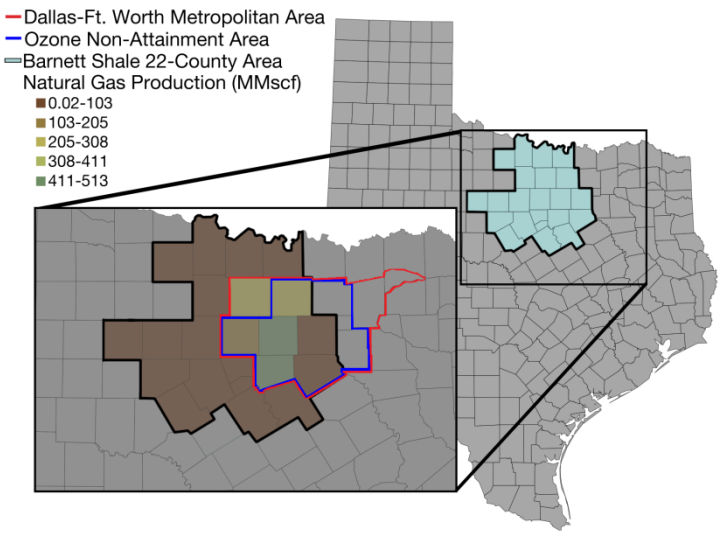


Figure 5. Counties with non-zero gas production from the Barnett Shale formation in 2009, and other demarcations of the Barnett Shale area in Texas (TRRC 2012)

1.2 Methods and Data

There are many different sources of GHG emissions in the natural gas industry (EPA 2011; ENVIRON 2010; API 2009), but the fundamental approach to estimating the magnitude of emission for all of them is:

$$[activity] * [emission\ factor] = [emission]$$

where the emission factor is in units of mass emission per unit activity, and "activities" for the natural gas industry range from counts of drilled wells or pieces of certain equipment to volume of natural gas produced, fuel combusted in an engine, or volume of water produced from a well (e.g., ENVIRON 2010; API 2009; EPA 1995). We call this approach *activity-based emission estimates*.

Different groupings of activity-based emission estimates lead to different types of results. *Inventories* aim to estimate emissions from a given chronological period, representing all activities occurring in that period. Inventories are developed with different foci: geographic, industrial sector, or pollutant. Few GHG emission inventories exist at higher spatial resolution than national, which aggregates industry- and pollutant-specific inventories produced at a national scale.

In contrast, LCAs aim to estimate all emissions attributable to a final product—here, a kilowatt-hour of electricity—scaling all the activities required over time and space to produce that unit of final product. Figure 6 depicts the scope of this LCA of electricity generated with natural gas, which covers all stages in the fuel cycle as well as the power plant's life cycle. As shown, this study combines an original inventory, for stages shown in blue, with best-available literature estimates for the remaining stages. Once co-products are separated from the produced gas, all emissions associated with their storage, processing, transport, and disposal or sale are considered outside of the system boundary for this study (as depicted with dashed lines).

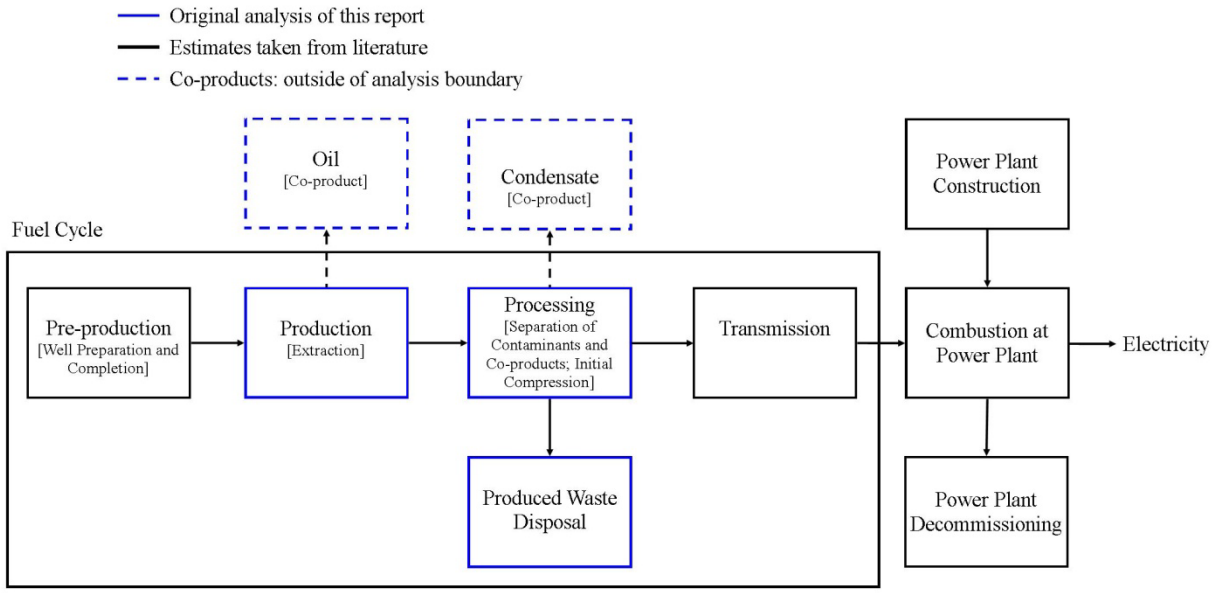


Figure 6. A life cycle assessment of electricity generated from natural gas involves estimating the GHG emissions from each life cycle stage

Because LCAs track the conceptual process chain—rather than the real supply chain—they typically model idealized activities, informed by as much empirical data on real conditions as possible. More than 30 LCAs of conventional natural gas follow this modeling philosophy (O'Donoughue et al. 2012). LCAs on shale gas that follow this approach include one employing a simplified, generic model of the industry (Stephenson et al. 2011); three assessing the U.S. national average or otherwise non-formation-specific conditions (Burnham et al. 2012; Skone et al. 2011; Howarth et al. 2011); and two assessing specific formations—Jiang et al. (2011) on the Marcellus formation and Skone et al. (2011) on the Barnett Shale.

More recently, some LCAs have leveraged EPA's national inventory of the natural gas industry's GHG emissions from a given year to simulate the process chain (Hultman et al. 2011; Venkatesh et al. 2011). These latter assessments benefit from emission estimates meant to be more closely related to actual performance; however, their estimates carry significant uncertainty given the current state of knowledge of activities and emission factors of this industry. In addition, results will change from year to year as the level of activity changes and may not reflect the life cycle of activities for a well (e.g., completions nationally in a given year may contribute a larger fraction of total emissions than what is reflective of their contribution within the life cycle of a single well).

In contrast to such approaches, this study translates estimates of VOC emissions to GHG emissions, capitalizing on a uniquely detailed inventory of VOC emissions and activities collected by the TCEQ. This approach enables a high-resolution GHG inventory for the production and processing of natural gas in the Barnett Shale play, within which individual GHG emissions from all relevant sources are estimated. Then, this annual inventory of the natural gas industry is translated into a longitudinal life cycle assessment for electricity produced from combustion of Barnett Shale gas. A brief summary of the approach is described below, with details provided in Appendix B.

1.2.1 Developing a GHG Emissions Inventory

Inventories of GHG emissions follow a long tradition of inventories for regulated air pollutants such as nitrogen oxides (NO_x) and VOCs that, in combination with sunlight, are precursors of ozone. Because of their role in demonstrating compliance with the National Ambient Air Quality Standard for metropolitan areas, the unit of analysis of these inventories is the county and large, so-called *point sources*. Point-source inventories contain detailed information related to all sources of emissions within specific facilities and are based on activity and characteristics information supplied by those facilities. Smaller, non-mobile sources (called *area sources*) are too numerous for regular, facility-specific information collection efforts and instead are tracked as a class, with emission factors (often simplified) correlating emissions with readily tracked activity data. The natural gas industry has many large point sources (including processing plants, compressor stations, and some production sites); the more numerous, smaller entities (including most production sites and some processing and transmission facilities) are classified as area sources.

Motivated by changing practices in the industry, in 2009, the TCEQ initiated a special inventory to collect detailed information on the activities and characteristics of the smaller entities in the natural gas industry that are normally part of the area-source inventory, similar to what is collected routinely from large point sources (TCEQ 2011). The purpose of the special inventory is to update and improve the TCEQ's estimates of emissions of regulated air pollutants from area sources, focused on the rapidly growing shale gas industry in the Barnett Shale area surrounding the metropolitan area of Dallas-Ft. Worth. The availability of the TCEQ's special inventory, in conjunction with its standard point-source inventory (TCEQ 2010), enables estimates of GHG emissions from activities within this important play at much finer resolution—by geography and entity—than is typically possible.

This study estimates GHG emissions from more than 16,000 individual sources detailed in three different TCEQ emission inventories:[22] the 2009 Point Source Inventory, 2009 Special Inventory, and 2008 Area Source Inventory (Pring et al. 2010). As shown in Figure 7, sources are characterized into profiles, which we further group into three general categories: combustion sources, potentially controllable leakage, and fugitives.[23] We differentiate between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from more dispersed leaks that are less feasible to control. Many of the individual sources analyzed in this report are potentially controllable, as are many additional emissions in the fuel cycle, which come from completions and workovers, waste disposal, and transmission. For each profile, we estimate emissions with a tiered approach based on the availability of data. In general, primary (most accurate) methods are based on reported volumes, such as fuel combusted or gas emitted, whereas secondary methods are based on reported VOC emissions or average usage conditions. We use primary methods for 83% of sources, secondary for 15%, and profile medians for the remaining 1%.

[22] Detailed inventory data were received through personal communication (TCEQ 2012).
[23] Skone et al. (2011) state that 25% of compressor engines in the Barnett Shale area are electrically powered, which would require the inclusion of emissions attributed to the generation of that electricity as an additional category. However, no electrically powered compressor engines are listed in the TCEQ data provided, and personal communication with the TCEQ (TCEQ 2012) stated that few, if any, such engines exist in the area.

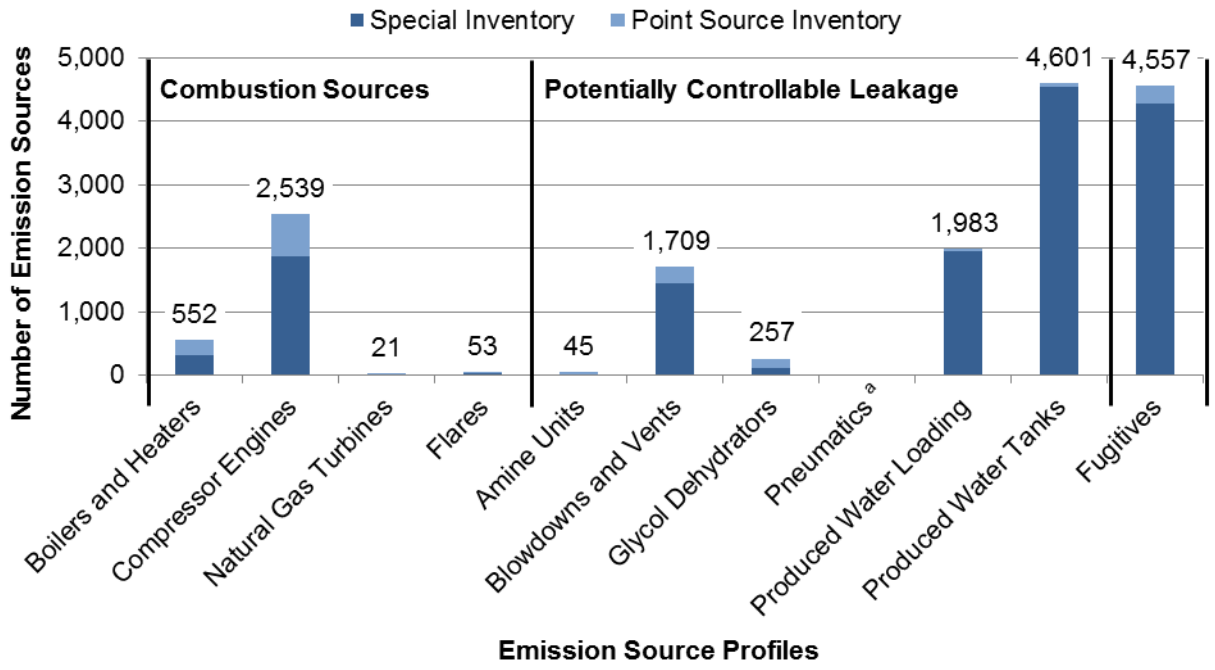


Figure 7. Greenhouse gas sources belonging to the natural gas industry in the 22-county Barnett Shale area; many are potentially controllable

[a]Pneumatics, from the area source inventory, have no count of individual sources

The central principle for translating a VOC emission inventory to one that estimates GHG emissions is the recognition that methane is a VOC,[24] albeit the slowest-acting one (Seinfeld and Pandis 2006). The key to translating VOC emission estimates to methane emissions is the availability of gas composition analyses reporting the proportion of methane, VOCs, and other gases (e.g., CO_2) within a sample. For validation purposes, the TCEQ requested many such gas composition analyses from reporting entities, which have been assembled into the largest known play-specific and publicly available set of gas-composition analyses. Organized by county, this database allows for estimation of methane and CO_2 content in gas emitted through venting and fugitive sources by ratio. It is well understood by geologists, petroleum engineers, investors, and others that gas composition varies within a geologic shale gas basin (e.g., Bullin and Krouskop 2008; Bruner and Smosna 2011); however, this is the first LCA or GHG emissions inventory to explore the implications of this variability.

In addition, other valued hydrocarbon products, such as condensate and oil, are created during the production and processing of natural gas. A principle of LCA research called co-product allocation dictates that the burdens of a system should be shared among all valued products from that system (e.g., Horne et al. 2009). In this study, emissions are allocated with respect to their share of the total energy content of all products from the fuel cycle. In addition to weighting the emissions from each source according to associated condensate and oil production, this means

[24] The VOCs typically tracked in Texas and national (EPA) regulations are non-methane, non-ethane VOCs. Accordingly, this report follows standard convention and refers to the set of non-methane, non-ethane hydrocarbons as VOCs. However, measurements of the composition of a gas sample (a so-called "extended analysis") include methane.

that the 25% of the sources in the TCEQ inventories that are associated only with the storage and handling of these co-products (e.g., condensate tanks) have been omitted.[25]

1.2.2 From Inventory to LCA

The GHG emissions inventory estimated here draws mainly from the TCEQ Special Inventory and Point Source Inventory for sources within natural gas production and processing life cycle stages (see Figure 7) (TCEQ 2010, 2011). Natural gas *production* relates to ongoing activities for the extraction of gas at wellheads. Natural gas *processing* relates to ongoing activities for the conversion of the produced gas to the required quality, composition, and pressure for pipeline transport.[26] In addition, the TCEQ area-source inventory is leveraged to estimate emissions associated with some activities at produced water *disposal* sites (Pring et al. 2010).[27]

Emissions from all sources within a fuel cycle phase are summed and then divided by the energy content of gas produced in that year to estimate an emissions factor in terms of mass of GHG emissions per unit of energy content of gas. Gas production statistics come from the Texas Railroad Commission for the 22-county play (TRRC 2012). Each GHG is weighted by its Intergovernmental Panel on Climate Change (IPCC) 100-year global warming potential according to standard procedure to normalize to units of CO_2e (Forster et al. 2007).[28] However, these emission factors cover only a portion of the natural gas fuel cycle, which itself is a subset of the life cycle of electricity generation from natural gas (Figure 6). Therefore, although the inventory data provide an important addition to the relatively sparse information about GHG emissions from shale gas development, literature sources are relied on for data on other emissions sources and life cycle stages—including sources such as completions, workovers, and liquids unloading—where there is considerable controversy currently about activity factors, emission reduction measures, and the magnitude of emissions.

Additional fuel-cycle stages include pre-production and transmission. *Pre-production* consists of one-time or episodic activities related to the preparation of wells, including the drilling and construction of well pads and wells, hydraulic fracturing to stimulate production, and well-completion activities. Emissions factors for these one-time activities, gathered from open literature (Santoro et al. 2011; EPA 2011; EPA 2012b; Skone et al. 2011), must be amortized over the lifetime production (EUR) of a well. *Transmission*, also estimated from literature data (Skone et al. 2011), involves the transport of processed gas to the power plant.[29]

This study combines fuel cycle emission factors into a full LCA by assuming a standard efficiency of conversion to electricity and adjusting for natural gas losses throughout the fuel cycle due to both leakage to the atmosphere and the use of production gas as fuel. This study

[25] Sources contained within the TCEQ inventories that are considered outside of the system boundary collectively represent 60% of total reported VOC emissions but a much smaller fraction of GHG emissions.
[26] Processing can occur either at wellheads or at separate processing facilities.
[27] Emissions from produced water tanks at produced water disposal sites are tracked by TCEQ; transport of the produced water to the disposal site and operation of engines at these sites are not considered in this analysis.
[28] Global warming potentials (GWP) are also reported by the IPCC for a 20 year horizon and 500 year. The 100-year GWP is used in this study to ensure consistency with the standard practice in LCA and GHG emission inventories. Results based on alternative GWPs or other metrics of climate impact could be developed based on the results reported here.
[29] Following Skone et al. (2011), we consider the final step of processing as initial compression to pipeline pressure.

assumes combustion in a modern natural gas combined-cycle facility with thermal conversion efficiency of 51% (higher heating value) to make the results comparable to the meta-analysis of electricity generated from combustion of conventionally produced natural gas (O'Donoughue et al. 2012). Many natural gas-fired power plants do not operate at this efficiency, and the results reported here can be easily adjusted to apply to alternative conditions. GHG emissions from power plant construction and decommissioning are also considered, amortized over the lifetime generation from the facility (O'Donoughue et al. 2012). Data on emissions from *combustion at power plant*, *power-plant construction*, and *power-plant decommissioning* come from open literature (Skone et al. 2011; Skone and James 2010).

The final estimate of life cycle GHG emissions is calculated as the sum of the estimated emissions from each life cycle stage, adjusted by the thermal efficiency and relevant production losses, as appropriate for each stage and detailed in the appendix. These full life cycle emissions are expressed in units of mass CO_2e per kilowatt-hour generated.

1.3 Results

In this section, we present and discuss key findings. Because of their relevance to the current debate about GHG emissions from natural gas, the full LCA results are presented first, followed by a comparison of these results to other published estimates. Then, the primary research contribution of this chapter is detailed: a high-resolution inventory analysis of the production and processing stages of the natural gas fuel cycle for Barnett Shale gas produced in 2009. Appendix B provides further results, including county-level analysis of production gas composition, allocation of emissions to co-products, and details supporting the presented results.

1.3.1 Life Cycle Emissions

GHG emissions from the natural gas fuel cycle are a focus in the public sphere and of the novel analysis of this study. However, the functional unit of the fuel cycle—a unit of energy content of processed natural gas delivered to the end user—is not easily comparable to that for other fuels for end-uses other than direct heating. Use of natural gas in the electric sector is the focus of this report and is the market for about 30% of natural gas production in 2011 (EIA 2012). Some have argued that future production of unconventional natural gas will only displace dwindling production of conventional natural gas (e.g., Howarth et al. 2012). However, others believe that natural gas could displace existing and new coal as fuel for electricity generation (e.g., Venkatesh et al. 2011; Hultman et al. 2011). Comparisons of the results to both alternatives are provided in the next section.

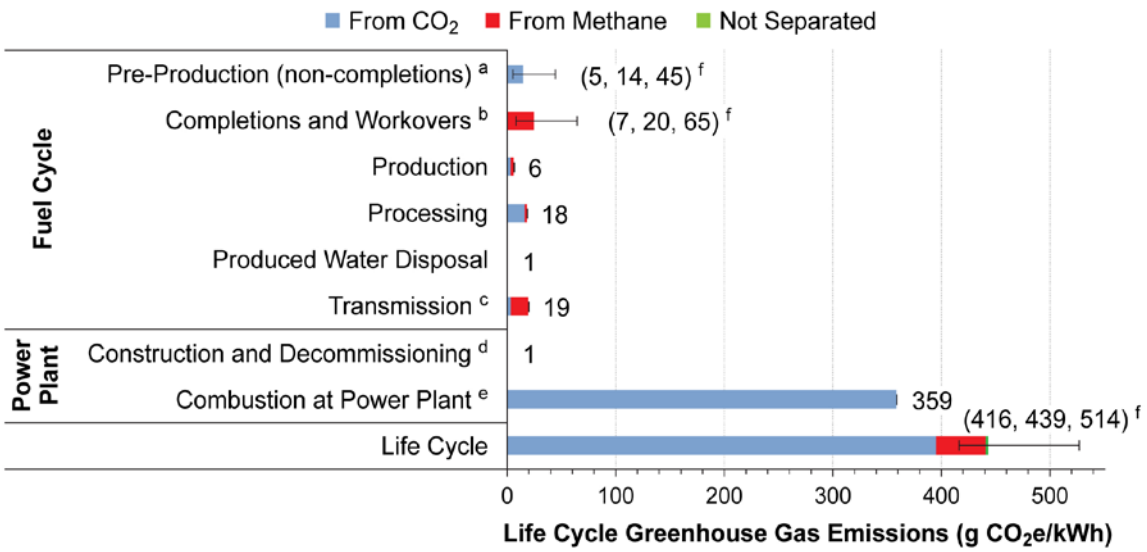
First, it is critical to emphasize the importance of GHG emissions from combustion at the power plant in the life cycle of natural gas electricity generation. The GHG emissions from combustion are primarily determined by the carbon content of the fuel and the efficiency of converting fuel (chemical) energy to electrical energy. Regardless of whether natural gas comes from conventional or unconventional sources, its chemical and thermal properties once processed are indistinguishable. With regard to carbon content of the fuel, coal has about 75% more carbon per unit fuel energy than gas. Regarding efficiency, when considering new power plants, most new natural gas generation assets will likely be natural gas combined-cycle, which has a characteristic higher heating value efficiency of 51% (O'Donoughue et al. 2012). This efficiency, chosen to maintain consistency with other studies for comparison purposes, does not reflect the existing

fleet of natural gas plants, but rather, it is characteristic of a modern, state-of-the-art facility. The existing fleet of coal power plants has an efficiency of close to 34% (Hultman et al. 2011), whereas new plants of either supercritical or integrated gasification combined-cycle designs will reach near 40% (MIT 2007). The efficiency improvement for natural gas combined-cycle plants over old or new coal plants is substantial, especially considering the inherent difference in carbon content of the two fuels (absent any coal decarbonization).

Assuming 51% efficiency for natural gas combined-cycle and 50 g CO_2/MJ carbon intensity of natural gas yields an estimate of nearly 360 g CO_2/kWh from combustion at the power plant. Other stages in the life cycle of the power plant (e.g., construction and decommissioning) add very little (~1 g CO_2e/kWh) to life cycle GHG emissions of electricity generation for fossil-fuel facilities because those emissions are amortized over lifetime generation.

Including the 2009 Barnett Shale fuel cycle emissions compiled in this study, total life cycle GHG emissions from natural gas combined-cycle electricity are estimated to be about 440 g CO_2e/kWh (Figure 8). Of this total, about 18% of life cycle GHG emissions (or 78 g CO_2e/kWh) are embodied in the fuel cycle of Barnett Shale gas, as defined in Figure 7. These fuel cycle emissions from unconventional gas are comparable to those estimated from the fuel cycle of conventional gas, which O'Donoughue et al. (2012) find have a median estimate of about 480 g CO_2e/kWh in the existing literature after methodological harmonization. (See the next section for further discussion and comparisons.) About 10% (or 42 g CO_2e/kWh) of life cycle emissions result from emissions of methane, mostly through venting during completion and workover and from the natural gas transmission pipeline network. These results are calculated assuming a base-case EUR of 1.42 bcf produced over the lifetime of a well, which is the play-average EUR used by the U.S. Energy Information Administration in their National Energy Modeling Systems (NEMS) model (INTEK 2011).

The results are fairly sensitive to alternative estimates of Barnett Shale well EUR, which other studies have found to be one of the most influential parameters on life cycle GHG emissions (Burnham et al. 2012; Stephenson et al. 2011; Skone et al. 2011; Jiang et al. 2011). Adjusting all one-time and episodic emissions by lower- and upper-bound estimates of well-level EUR (INTEK, 2011) yields estimates of life cycle GHG emissions that vary by nearly 100 g CO_2e/kWh. Figure 8 displays the use of reported lower- and upper-bounds of well-level EUR for the Barnett Shale play (INTEK 2011) of 0.45 and 4.26 bcf/well, respectively. Life cycle GHG emissions then range between about 420 and 510 g CO_2e/kWh owing to the tested variability in assumed EUR.



[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al. 2011).
[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and methane mass fraction of 66.2%.
[c] Based on Skone et al. (2011)
[d] Based on Skone and James (2010)
[e] Based on Skone et al. (2011)
[f] Multiple estimates, in parentheses, pertain to high EUR, base-case EUR, and low EUR, respectively. Single estimates pertain to stages without sensitivity to EUR. The error bar is plus or minus the total bar length (life cycle GHG emissions).

Figure 8. Combustion at the power plant contributes the majority of GHG emissions from the life cycle of electricity generated from Barnett Shale gas

1.3.2 Comparisons to Other Studies

There are three important points of comparison for the life cycle GHG emission results presented here:

1. Previous estimates for electricity generated from shale or other unconventional gas
2. Previous estimates for electricity generated from conventional gas
3. Previous estimates for electricity generated from coal.

Direct comparison of the results of LCAs is hindered by the sensitivity of results to alternative assumptions of key parameters and other methodological considerations. Harmonization, which is a meta-analytical approach to enable more direct comparison, has been demonstrated for a wide range of electricity generation technologies (e.g., Burkhardt et al. 2012; Warner and Heath 2012). For coal-fired electricity generation, Whitaker et al. (2012) harmonized 164 estimates from 53 LCAs on four coal generation technologies (i.e., subcritical, supercritical, integrated gasification combined cycle, and fluidized bed). More recently, this approach has been applied to the LCA literature on natural gas-fired electricity generation, where estimates from 42 LCAs on

conventionally produced natural gas (O'Donoughue et al. 2012) and 6 shale gas LCAs (Heath et al. 2012) have been harmonized. Results from these studies are used for comparing results of this report to those in the literature because they ensure fair and consistent comparisons and enable insight useful for broad decision-making.[30] It is important to note that the results of this study were developed using the same key assumptions and system boundaries as in the harmonization of the literature estimates for conventional and shale gas—and, more broadly, with those for coal.

Figure 9 displays the results of this chapter's analysis (base case and EUR sensitivity)—which estimates life cycle GHG emissions from Barnett Shale gas produced in 2009 and combusted to generate electricity in a modern natural gas combined-cycle turbine—compared to other estimates, which are based on a systematic review and harmonization of existing literature. Compared to other estimates for shale gas electricity generation, the base case results of this methodologically independent assessment are near the 25th percentile of harmonized estimates, which is similar for the comparison to harmonized conventional natural gas estimates. High and low EUR scenarios are also within the range of previous estimates for shale and conventional gas life cycle GHG emissions. The results are also found to be considerably lower than those for coal—nearly half of the median estimate of 980 g CO_2e/kWh (Whitaker et al. 2012), even under low EUR conditions.

[30] Estimates of life cycle GHG emissions for specific facilities can legitimately differ from those produced through harmonization. See Heath and Mann (2012) and other harmonization articles in the Special Issue on Meta-Analysis of LCA in the *Journal of Industrial Ecology* (http://jie.yale.edu/LCA-meta-analysis) for further discussion.

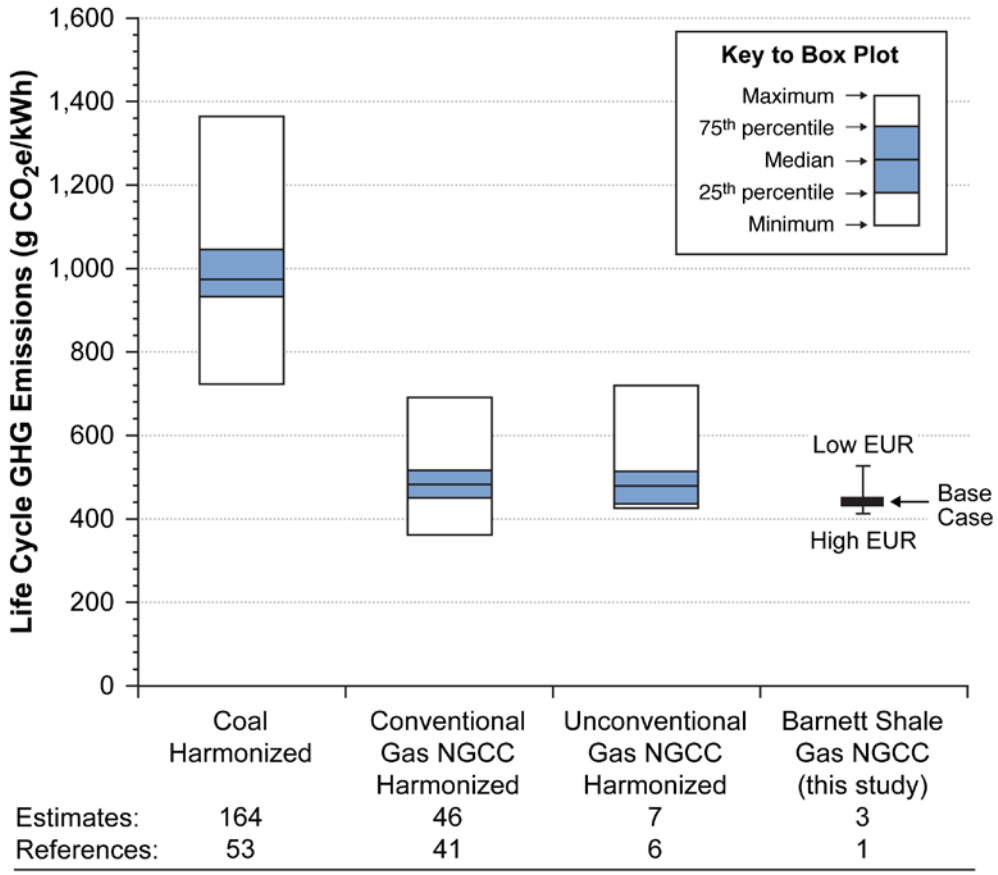


Figure 9. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization. [31]

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

The rest of this section briefly reviews the key differences that could explain the relationship between the results from this study and those from other shale gas LCA literature. More detailed discussion of each of the existing shale gas life cycle GHG emission estimates can be found in Heath et al. (2012). Differentiating factors that tend to reduce estimates of life cycle GHG emissions for our study compared to some others include: equitably sharing the burdens of natural gas production with valuable co-products; not considering nitrous oxide emissions throughout the life cycle or non-CO_2 emissions from power-plant combustion; not considering embodied GHG emissions of purchased fuels; and not considering transport of produced water to disposal wells. None of the following factors are considered significant points of

[31] See O'Donoughue et al. (2012), Heath et al. (2012) and Whitaker et al (2012) for further description of the review and harmonization of estimates of life cycle GHG emissions from electricity generated from conventional natural gas, unconventional (mostly shale) gas and coal, respectively. The studies reviewed and harmonized in Heath et al. (2012) for unconventional (mostly shale) gas are: Howarth et al. (2011); Burnham et al. (2012); Jiang et al. (2011); Skone et al. (2011); Stephenson et al. (2011); Hultman et al. (2011).

underestimation: negligible impacts found in previous analyses,[32] contributions only to the fuel cycle (which represents 18% of total life cycle emissions), and negligible quantities of relevant sources.[33] Differentiating factors that tend to increase life cycle GHG emission estimates for particular literature estimates compared to ours include: higher natural gas leakage estimates (Howarth et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011; Jiang et al. 2011); higher estimate of methane content of produced gas (Jiang et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011); and inclusion of natural gas distribution for transport of gas to the power plant[34] (Jiang et al. 2011; Howarth et al. 2011; Hultman et al. 2011). On the other hand, EURs considered in this chapter are considerably lower than for other studies. This is especially true for the sensitivity analyses conducted by this and other studies, where the low-bound case for all other studies is at least twice the lower-bound estimate reported by EIA for the Barnett Shale play (INTEK 2011).[35]

A key distinguishing feature of the practices typically assumed for conventional as compared to unconventional wells is liquids unloading (i.e., periodic removal of liquids and other debris from a well). EPA has found that this practice occurs frequently—31 times per year on average (EPA 2011)—every year in the life of a well. And emissions from this practice, even when amortized over lifetime production of a well as in LCAs, are significant (e.g., Burnham et al. 2012). A recent survey of 91,000 wells by two industry associations suggests that at least for this sample, emissions from liquids unloading are nearly 80% lower than EPA's estimate (Shires and Lev-On 2012). Not only is the magnitude of emissions from liquids unloading controversial, but the same industry survey suggests that liquids unloading is also practiced on unconventional wells, reversing previous assumptions (Shires and Lev-On 2012). If liquids unloading were practiced on Barnett Shale wells,[36] then life cycle GHG emissions under average-EUR conditions would increase between 6 and 28 g CO_2e/kWh depending on the emission rate assumed[37] and potentially as high as 100 g CO_2e/kWh under low EUR conditions.

1.3.3 Fuel Cycle Methane Losses

Throughout each stage of the fuel cycle, a portion of the produced gas is used or lost: gas is used as a fuel for combustion activities, and it is lost when it leaks to the atmosphere either through potentially controllable leakage or fugitive emissions. As a potent GHG, methane emitted to the atmosphere is especially important to understand.

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[32] For example, Skone et al. (2011) find that nitrous oxide contributes 0.04% to the total life-cycle GHG emissions for a natural gas combined-cycle plant. They also found that nitrous oxide and methane contribute 0.001% and 0.004%, respectively, to the GHG emissions from the energy-conversion facility (which primarily consist of fuel combustion emissions) for a natural gas combined-cycle plant.

[33] Fewer than ten engines in the inventory are identified as using purchased fuels (i.e., gasoline or diesel).

[34] To approximate an upper bound for such an omission, consider that even doubling the estimated emissions from transmission adds only 19 g CO_2e/kWh, or about 4%, to the total life-cycle GHG emissions.

[35] Base-case EURs were 3, 3.5, 3, 2.7, and 2 bcf for Howarth et al. (2011) (average of estimates reported in Table 1), Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011) and Stephenson et al. (2011), respectively. Lower bounds tested were 1.6, 2.1, 2.7, and 1 bcf for Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011), and Stephenson et al. (2011), respectively.

[36] Assuming 30-year well lifetime (Skone et al. 2011), 1.42 bcf EUR (INTEK, 2011), and 12% emission reductions (Burnham et al. 2012).

[37] The low estimate assumes an emission rate according to Shires and Lev-On (2012), whereas the high estimate assumes an emission rate according to EPA (2011).

This section reports two related metrics, each important for different purposes. The first metric we refer to as *natural gas losses*, which signifies the percentage of produced natural gas either lost or consumed along the fuel cycle, expressed in units of volume natural gas lost per volume natural gas produced.[38] The second metric we refer to as *methane leakage,* which signifies the volume of methane released to the atmosphere in relation to the amount of gas produced, expressed in units of volume methane emitted per volume natural gas produced. A leakage rate reported in these units enables rapid estimation of methane emissions based on a known amount of produced natural gas.

Based on the analysis of TCEQ inventories for natural gas production and processing emissions, as well as published estimates for other fuel cycle phases, this study estimates that 1.5% of produced gas is emitted to the atmosphere before reaching the power plant (see Table 1). Much of this is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas, this equates to a *leakage rate* across the fuel cycle of 1.3% methane volume per volume of natural gas processed, based on the assumed play-average EUR of 1.42 bcf/well. Because of the contribution of one-time emissions to these results, they are sensitive to EUR; low EUR corresponds to an estimated 2.8% methane leakage rate and the loss of 8.9% of produced gas across the fuel cycle, whereas high EUR corresponds to an estimated 0.8% leakage and 6.5% losses.

Table 1. Loss of Produced Gas along the Fuel Cycle[a]

	Completions and Workovers[b]	Production	Processing	Transmission[c]	Total
Extracted from Ground	100.0%				100.0%
Fugitive Losses	–	0.1%	0.0%	0.5%	0.6%
Potentially Controllable Leakage	0.8%	0.1%	0.0%	0.0%	0.9%
Combusted as Fuel	–	0.9%	3.9%	0.8%	5.6%
Delivered to Power Plant					92.9%

[a] Reported as volume of natural gas consumed or lost per volume of natural gas produced
[b] See footnote to Figure 9
[c] From Skone et al. (2011)

1.3.4 Air Pollutant Emissions Inventory-Based GHG Emissions Estimates

This study develops emissions factors for the production and processing stages of shale gas development based on original estimates of GHG emissions from TCEQ inventories and the Texas Railroad Commission's production statistics. These emission factors are shown in Figure using the functional unit of grams CO_2e per mega-joule of natural gas (i.e., g CO_2e/MJ).

[38] Although the use of natural gas in production and transportation processes is for beneficial purpose, it nonetheless represents the loss of a potentially marketable product. For instance, increasing the efficiency of engines at pipeline booster stations would increase the amount of product delivered to the end user. From this perspective, we employ the simplified terminology of "loss" of natural gas to include its use prior to sale to an end user.

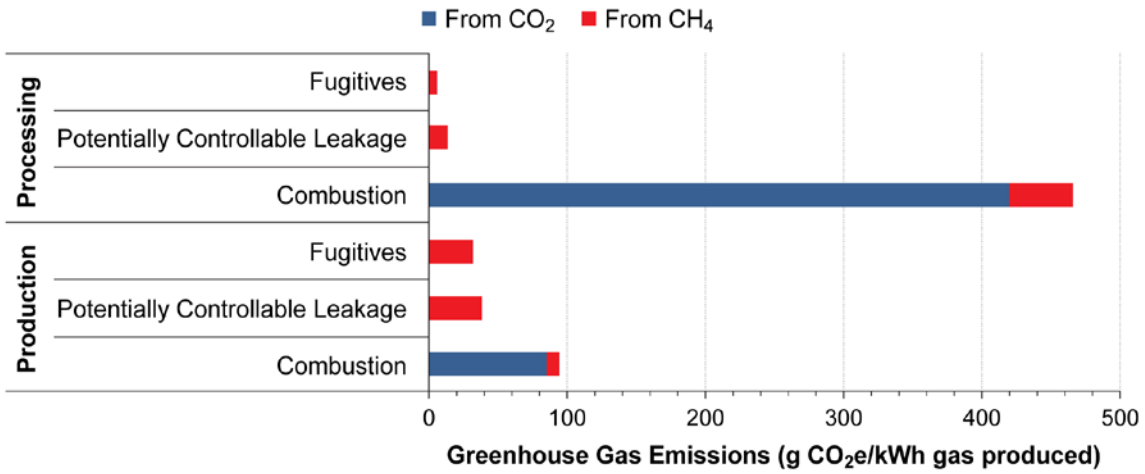

Figure 10. Inventory-based analysis of production and processing fuel cycle stages showing that the majority of GHG emissions are CO_2 resulting from combustion, although the CO_2e from methane emissions is significant

Most noticeably, the majority of GHG (CO_2e) emissions in both of these life cycle stages comes from CO_2 emissions from combustion sources. These emissions represent 53% of the total GHG emissions for the production stage and 87% for the processing stage. In the production stage, 90% of CO_2 emissions come from a large number of four-cycle rich-burn engines, nearly all of which are not normally individually tracked in the point-source inventory. Of the 1,564 compressor engines contributing to CO_2 emissions during natural gas production, only seven are reported to the point-source inventory, with the vast remainder of sources (and 99.9% of the CO_2 emissions) being reported only in the special inventory. Although the point-source inventory is intended to cover major emissions sources, the large number of individually smaller sources that are only captured by the special inventory play an important role in the GHG emissions from natural gas production in the Barnett Shale play. In the processing stage, 49% of CO_2 combustion emissions come from 405 4-cycle, lean-burn engines; 21% from 273 4-cycle, rich burn; 20% from 552 external-combustion boilers and heaters; and the remaining CO_2 emissions come from natural gas turbines, other compression engines, and equipment flares. In contrast to the production stage, 76% of these sources—representing 79% of the CO_2 emissions—are covered by the point-source inventory. Direct emission of CO_2 from fugitives and from processing (to achieve pipeline-quality specifications) is negligible but included for completeness.

Of the remaining GHG emissions, more methane emissions come from potentially controllable gas leakages than from fugitives. Specifically, only 41% of methane released in the production stage comes from fugitives. The 49% of methane coming from potentially controllable leakage in the production stage is dominated by emissions from pneumatic pumps and controls, which are a focus of recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane leakage. Of the 21% of methane emissions in this life cycle stage coming from potentially controllable leakage, more than half comes from emissions from produced water tanks, and almost a third from emissions from glycol dehydrators. Despite only a small proportion of combustion emissions being methane, combustion activities still account for

69% of the total methane emitted in the processing stage as a result of the large numbers of engines.

1.3.5 Sensitivity to Gas Composition Analysis

Because it reflects a key differentiation of this study from previous analyses, this section explores the sensitivity of this study's results to assumptions about the composition of the produced gas. Specifically, this section compares the study's main results—which are based on county-specific gas composition estimates (see Appendix B)—with results based on two alternative assumptions about produced gas composition.

The first alternative calculates emissions using a play-level gas composition estimate, which reflects a production-weighted average of all county estimates with original data. The second alternative uses EPA's reported national average production gas composition (EPA 2011) as the estimated composition for all sources. The national average is used for comparison because most LCAs rely on this gas composition, even for play-specific estimates (e.g., Skone et al. 2011). Table 2 reports the difference in emission estimates for CO_2, methane, and CO_2e using these alternative gas composition analyses compared to this study's spatially explicit approach (main results).

Table 2. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Inventoried GHG Emissions for the Barnett Shale Play

	Difference from Main Results		
	CO_2	Methane	CO_2e
Production and Processing Combined			
Main Results	–	–	–
Barnett Shale Average	-0.5%	2.6%	0.2%
National Average	-3.5%	5.7%	-1.5%

The overall impact is negligible of using spatially explicit estimates versus the Barnett Shale average, which is a production-weighted average of individual estimates: the effect on the two different GHGs cancel out in terms of CO_2e. The impact of using national average gas composition estimates is larger, but still small. As shown by the difference in Barnett Shale average versus national average results, these impacts come not from shifting to uniform gas compositions, per se, but rather, from using gas composition estimates less reflective of the specific gas analyses obtained from locations within the Barnett Shale region.

However, estimates differ more substantially when looking at a finer scale, as shown in Table 3, which focuses on production-stage emissions estimates for the four top-producing counties in the Barnett Shale. Using Barnett Shale or national average gas composition can lead to estimates one-third lower or higher for Tarrant and Wise counties, respectively, compared to using the county-level average. This variation comes from the substantial difference in estimated gas composition across counties, also shown in the lower portion of Table 3 for the representative gas constituents of VOCs, CO_2, and methane. Note that Tarrant and Wise counties both deviate substantially from the Barnett Shale average, as well as from the national average.

Table 3. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Estimated Production Emissions at the County-Level

	Denton County[a]	Johnson County[a]	Tarrant County[a]	Wise County[a]	22-County Total	
Barnett Shale average vs. main results	12%	-5%	-33%	29%	1%	
National average vs. main results	15%	-11%	-36%	29%	-3%	
	Denton County[a]	**Johnson County[a]**	**Tarrant County[a]**	**Wise County[a]**	**Barnett Shale play average[b]**	**National average[c]**
Volatile organic compounds content[d]	18%	19%	6%	23%	16%	18%
CO_2 content[d]	2%	2%	1%	3%	2%	2%
Methane content[d]	63%	63%	80%	56%	66%	78%

[a] Only the four top-producing counties in the Barnett Shale play are shown.
[b] Production-weighted average across the 22 counties of the Barnett Shale play
[c] As reported in EPA (2011)
[d] Percentage by mass

These results have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays. Furthermore, when detailed activity data at the site or source level are developed, these data should be matched by detailed gas-composition analyses for the most accurate outcomes.

1.3.6 Areas for Improvement in Understanding

The estimate of life cycle GHG emissions from gas produced from Barnett Shale in 2009 reported here advances our understanding through rigorous analysis of more than 16,000 sources of emissions and accounts for the known spatial heterogeneity in gas composition within the Barnett Shale play. However, future efforts should explore the sensitivity of the estimates herein to the many contributing parameters and several other aspects because further improvement remains.

Chief among the areas for improvement are a greater number of recent measurements of emission factors and statistically representative surveys of current practices characterizing GHG emissions from the natural gas industry. For instance, there is a critical lack of measurements of emissions for completion and re-completion (workover) activities that account for different physical and operational conditions based on use of reduced-emission completion equipment, variations in gas flow during flowback and initial production, and mud degassing (EPA 2011; Shires and Lev-On 2012; CERA 2011; Burnham et al. 2012). Likewise, better and more recent measurements of fugitive emissions from well and processing equipment, as well as pipelines at all stages—gathering, transmission, and distribution lines—are warranted because the existing data are sparse and old. The prevalence of emission-reduction practices (e.g., flaring) during completion, workover, and other activities is another area of considerable lack of empirical information and variability in current assumptions (Heath et al. 2012) that would improve understanding of life cycle GHG emissions.

Furthermore, if other well-specific information—such as annual and lifetime gas, condensate, oil, and produced water production, and lifetime workovers—were available and could be

matched to the TCEQ emissions inventories, then fuel cycle and life cycle GHG emissions could be estimated at the well level. These results could allow for consideration of well-level variability, with implications for the design of efficient strategies to control emissions. In particular, given the substantial sensitivity of results to EUR (total life cycle GHG emissions differ from base results by -5% or +17% for upper and lower EUR estimates, respectively), better well-specific information on EUR will improve the precision of emissions estimates. However, EUR is neither geographically nor temporally constant; rather, it relates both to physical characteristics of natural gas deposits and to the (constantly evolving) technical and economic feasibility of recovery of that natural gas. An improved and sophisticated understanding of EUR is therefore necessary. Finally, production activity is often planned for a field based on a set of wells; when initial wells decline in production, they could be restimulated and other wells could be drilled within the same area (through new laterals or new surface sites). Considerable knowledge of these dynamics is currently lacking. Yet, it is important to understanding GHG emissions in the context of deployment strategies used by many large players.

We have assembled the largest publicly available database of gas composition analyses for a shale gas play, and the counties with highest production correspond to those with the greatest number of analyses. However, given the sensitivity of the study's county-level results to the gas composition, it appears to be warranted to devote further effort toward improving the availability of production gas composition analyses specific to a region of interest. A random-sampling campaign conducted by a third party would be an ideal match for the methods used in this chapter if they are deemed useful for future analyses. A nearer-term objective could be to simply increase the pool of gas analyses from any entity willing to make such data available. Results of such further investigation could have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays.

Further investigation of emissions from liquids unloading from unconventional wells is also warranted given the potentially significant GHG emissions from this activity, as described above. An emissions sampling strategy that accounts for variability across geography, gas type, well type, operator size, and operational practices, among other factors, should lead to an improved understanding of the potential for GHG emissions from liquids unloading for conventional and unconventional wells. Additional activity data regarding frequency of unloading and how this might change over the lifetime of a well, proportion of wells requiring unloading, and prevalence and effectiveness of emission-reduction activities are necessary to develop a more complete understanding of the emissions from this practice. Finally, because emissions from this episodic activity are amortized over lifetime production for use in LCAs, more certainty in the estimate of EUR would improve the accuracy of life cycle emission estimates.

Practices in the natural gas industry change over time, as do resource characteristics. Estimates of GHG emissions should be periodically repeated to reflect those changing practices and characteristics, using the most up-to-date and accurate data on emissions, emission-reduction practices, resource characteristics and activities available. Estimates could also be developed for future conditions based on expected changes in practices due to, for instance, full implementation of promulgated regulations. Such estimates could be compared to goals for GHG

emission reduction to highlight whether additional emission reductions are necessary to reach those goals.

Analogously, industry practices and resource characteristics vary by location owing to differences in, for instance, geology, hydrology and state regulations. Estimates of GHG emissions should be developed in other locations using as much geographically specific data and information as possible. Furthermore, GHG emissions will also differ by gas type—not only by broad categories such as conventional and unconventional, but also, by different types of each, e.g., shale, tight, and coal-bed methane for unconventional, and associated, onshore, and offshore for conventional. GHG emissions for each of these types should be characterized so that a more accurate understanding of drivers of variability (if any) by type can inform discussions of opportunities to reduce emissions.

Finally, the bottom-up, engineering-based inventory of emissions should be confirmed through top-down atmospheric measurements. Literature suggests that emissions are typically underestimated through bottom-up approaches compared to concentrations of those same pollutants in the atmosphere (e.g., Townsend-Small et al. 2012; Petron et al. 2012). This effect likely results not only from issues such as non-reported sources, but also from inaccuracies that inherently arise from the use of non-specific methods that depend on average or ideal conditions. Although source attribution is still challenging and these measurements are expensive, they provide a much-needed confirmation of when inventories are accurate and when updates and improvements are necessary to support sound decision-making.

1.4 Conclusions

The aim of this research is to advance the state of knowledge of life cycle GHG emissions from electricity generated from shale gas extracted from a specific play—the Barnett Shale play in north Texas—using data sources independent of those used in previous LCAs of natural gas. We leveraged inventories of regulated air pollutants collected and screened by the Texas Commission on Environmental Quality for a 2009 special inventory of the Barnett Shale gas production, processing, and transportation sectors and their regular point- and area-source inventories in the 22-county Barnett Shale area. We used data supplied by the industry to TCEQ regarding the emissions and characteristics of more than 16,000 individual sources. The TCEQ inventories are used to estimate VOC emissions, a precursor of ozone. VOC emission estimates were translated to methane and CO_2 emissions by using gas composition analyses that report proportions by mass of each constituent. This study compiled a large dataset of such gas composition analyses at the county level, enabling a quantitative accounting of the significant variability that exists within the play of methane, CO_2, and other compounds.

Based on the analysis of TCEQ inventories and the addition of missing life cycle stages not included in those inventories, this study estimates that electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 is associated with about 440 g CO_2e/kWh generated, with a sensitivity range based on published high and low EURs of 420 to 510 g CO_2e/kWh. Thus, the life cycle GHG emission result is sensitive to the lifetime production of wells, where additional research would be helpful to more precisely estimate life cycle GHG emissions. Regardless of this uncertainty, however, this chapter's main conclusion is that life cycle GHG emissions from electricity produced from Barnett Shale natural gas lie within the range of previously published estimates for GHG

emissions (after methodological harmonization) from electricity produced by either conventional or unconventional natural gas (O'Donoughue et al. 2012; Heath et al. 2012). Furthermore, this report's estimate of life cycle GHG emissions is less than half of the median of published estimates for coal-fired electricity generation (after methodological harmonization) (Whitaker et al. 2012). It should be noted that the estimate of life cycle GHG emissions developed here is not strictly applicable to other locations or years, and that several important aspects of uncertainty in the methods of this research should be improved through additional research. However, the broad agreement between the estimate developed here and those published independently for both unconventional and conventional gas increases confidence in our understanding of life cycle GHG emissions of natural gas used for electricity generation.

This study found that about 19% of base case life cycle GHG emissions results from the fuel cycle of Barnett Shale gas (pre-production through transmission). About 10% of base case life cycle GHG emissions are methane, mostly vented during completion and workover and released from the natural gas transmission pipeline network. Only 11% of life cycle GHG emissions depend on characteristics of shale gas (e.g., extraction techniques, composition); the vast majority of life cycle emissions are not affected by the type or origin of the gas because they occur after processing that has the function of creating a homogenous product.

With regard to the fuel cycle GHG emissions, which were the focus of the analytical effort of this chapter, the vast majority comes from CO_2—80% or more of which is emitted from combustion sources (mostly engines and turbines) in the production and processing stages. The majority of emissions coming from natural gas production activities is from sources not routinely tracked individually (because they do not meet regulatory thresholds) in a classic example of how important the more numerous small sources can be to total emissions and how challenging quantifying and reducing emissions from the natural gas industry will be for regulators. Only through special inventories, such as the one conducted in 2009 for the Barnett Shale area, is it possible to have the kinds of detailed information necessary to estimate source-specific emissions for the vast majority of production sources within this industry. By contrast, processing sources are typically larger, meeting the threshold for annual emissions reporting under the regular point-source inventory.

We find that methane leakage, though playing a smaller role in life cycle GHG emissions from this analysis of 2009 Barnett Shale gas as compared to others, comes mostly from what we have classified as potentially controllable sources, rather than from fugitives—with implications for the potential for GHG emission reductions in the natural gas industry. In gas production, 40% of methane released comes from fugitive sources; methane emitted from potentially controllable leakage in the production stage comes mostly from pneumatic pumps and controls, which are specifically addressed in recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane emissions. As for potentially controllable leakage in processing, half comes from emissions from produced water tanks and a third from glycol dehydrators.

Our method represents an improvement in accuracy by accounting for spatial differences in gas composition as compared to previous LCAs. For instance, methane content of raw gas from the top four producing counties ranges from 56% to 80%, with implications for how much methane is released in venting or fugitive emissions. Previous research has either used play-level average

gas composition (e.g., Jiang et al. [2011] for the Marcellus) or the national average. For Barnett Shale total emissions, the difference in results between using county-level gas composition compared to a play-wide average composition is relatively small; however, the improvement is more significant compared to using national average composition.

The overall results for the Barnett Shale play are only marginally sensitive to the variability in gas composition across the play because of offsetting differences. But the variability observed in gas composition has implications for accurate estimation of GHG emissions at finer spatial resolution, monitoring programs, and regulatory strategies. This study found differences in GHG emission estimates at the county level compared to estimates using national average figures; furthermore, inventories of the level of detail of the special inventory provide an important piece of the overall story of emissions. Therefore, accurate usage of such detailed information needs to be matched by more detailed input information, notably gas composition analyses. The database assembled for this study is a first step toward developing more robust databases in the Barnett and other natural gas basins around the country.

Improvements can be made to the estimate produced here of life cycle GHG emissions for 2009 Barnett Shale gas used in a modern combined cycle electricity generator. But this study's methodologically independent estimate confirms previous research on shale gas electricity generation. In addition, it is similar to previous estimates for generation using conventionally produced natural gas, and it is less than half of that estimated in other studies for coal. Liquids unloading, which is typically assumed to occur only for conventional wells, accounts for most of the difference between this study's estimate and that developed based on meta-analysis and updating of more than 40 references reporting life cycle GHG emissions for electricity generated from conventionally produced natural gas. However, evidence has emerged suggesting that liquids unloading is also a practice applicable to unconventional wells. If confirmed for Barnett Shale wells in particular, then it means that the estimate reported here should be updated accordingly. The high carbon content and significantly lower thermal efficiencies of coal-fired power plants account for their substantially higher life cycle GHG emissions.

2 Regulatory Framework Governing Unconventional Gas Development

2.1 Introduction

Rapid development of unconventional natural gas in the United States in recent years has raised a number of important environmental concerns, including ground and surface water contamination; disposal practices for frac flowback, produced water, and other associated drilling wastes; impacts on local and regional air quality; methane leakage and venting rates; and increased traffic, noise, and other community impacts. It is clear that regulations have increased at virtually all levels of governance in response to the unconventional gas boom. Various commissions, advocacy groups, and research organizations have weighed in on the pros and cons of additional regulation, including two reports issued by the Secretary of Energy Advisory Board Shale Gas Production Subcommittee ("SEAB Subcommittee").[39] But questions persist regarding the sufficiency of these regulations across differing jurisdictions and the adequacy of compliance monitoring and enforcement in the face of rapid growth.

Because of the "distributed" nature of unconventional gas development and the substantial increase in wells in key basins,[40] local land-use conflicts have erupted in certain areas of the country that have led to restrictions and moratoria on drilling by state, county, and municipal governments, raising questions about the industry's continued social license to operate in specific jurisdictions[41] (Dryden 2012; Middlefield 2012). In response, some states—notably Pennsylvania—have recently enacted legislation to restrict the ability of local governments to

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[39] *See e.g.*, U.S. DOE, *Secretary of Energy Advisory Board Shale Gas Production Subcommittee, Ninety-Day Report,* (Aug. 11, 2011) and *Second Ninety-Day Report* (Nov. 18, 2011), http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf; National Petroleum Council, *Prudent Development Realizing the Potential of North America's Abundant Natural Gas and Oil Resources* (2011), http://www.npc.org/NARD-ExecSummVol.pdf; Cardi Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issue*s, prepared on behalf of Cornell University (Sept. 2011), http://www.greenchoices.cornell.edu/downloads/development/marcellus/Marcellus_CaRDI.pdf; Thomas Kurth, et al., "American Law and Jurisprudence on Fracing," Haynes and Boone, LLP (2010), http://www.haynesboone.com/files/Publication/3477accb-8147-4dfc-b0b4-380441178123/Presentation/PublicationAttachment/195a3398-5f02-4905-b76d-3858a6959343/American_Law_Jurisprudence_Fracing.pdf ; Bipartisan Policy Center, Energy Project, *Shale Gas: New Opportunities, New Challenges* (Jan. 2012), http://www.scribd.com/doc/95194795/Shale-Gas-New-Opportunities-New-Challenges; Charles G. Groat and Thomas W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas*, report prepared for the Energy Institute, University of Texas at Austin (Feb. 2012), http://energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf; Rebecca Hammer, et al, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewat*er, Natural Resources Defense Council (May 2012) http://www.nrdc.org/energy/files/Fracking-Wastewater-FullReport.pdf; International Energy Agency, Golden Rules for a Golden Age of Gas, 9-10 (May 29, 2012), http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf (discussing the importance of public acceptance for continued expansion of unconventional gas development in the U.S. and abroad).

[40] For a graphic depiction of the rapid increase in shale gas wells in Pennsylvania, see U.S. Energy Information Administration, "Horizontal drilling boosts Pennsylvania's natural gas production," available at http://www.eia.gov/todayinenergy/detail.cfm?id=6390.

[41] Some national governments, including France and Bulgaria, have also banned hydraulic fracturing (BBC News 2012). For a list of current moratoria and bans, see Sierra Club, FRAC Tracker, http://www.sierraclub.org/naturalgas/rulemaking/.

regulate unconventional gas development.[42] Other states, such as Colorado, have engaged in multi-stakeholder processes to strengthen and continue to revise new rules for oil and gas development that have been embraced by multiple constituencies and paved the way for innovative legislation that is re-shaping the electric power sector in the state (COGCC 2008; Xcel 2012). See Textbox 1 for more on Colorado's recent experience. But even in those states, such as Colorado, where oil and gas development has been a feature of the landscape for decades, a number of communities have expressed concerns about the proximity and pace of unconventional gas development and are seeking to impose new restrictions on development.[43]

Text Box 1: Colorado's Clean Air-Clean Jobs Act

In 2010, then Governor of Colorado Bill Ritter introduced landmark legislation that fundamentally altered the energy make-up of the state's electric power sector. The legislation, HB 1365, also known as the "Clean Air-Clean Jobs Act," required regulated utilities to reduce emissions of nitrogen oxides by 70% to 80% or greater from 900 megawatts of coal-fired generation by 2018 and meet certain "reasonably foreseeable" environmental requirements, such as lower ozone standards. To meet these targets, the state's regulated utilities proposed a plan that included retiring aging coal-fired power units, retrofitting others with state-of-the-art clean technology, and expanding capacity for units powered by natural gas and renewable energy sources. The Act had broad support from a number of constituencies including local Front Range governments, local and national non-governmental organizations, Xcel Energy and the natural gas industry (CCC 2010; Xcel 2012). Importantly, much of this support can be tied to the state's decision to first put in place strong rules for the development of its oil and gas resources before introducing legislation that would very likely lead to increased production. Many believe there is still work to be done to ensure that production is done properly statewide, especially in the Front Range, where new production is taking hold that did not exist to the same extent in 2008. However, many point to the Colorado model as an example of collaboration, innovation, and leadership that can be replicated elsewhere.

In short, the regulatory landscape affecting unconventional gas development is complex, dynamic, and multi-layered. Going forward, there is a risk of increased regulatory fragmentation within and among gas-producing basins, as well as a lack of coordination among the different government entities responsible for regulating and ensuring compliance with various aspects of unconventional gas development, leading to additional uncertainty, gaps, redundancies, potential delay for producers, and under-enforcement.[44] At the same time, leading companies continue to

[42] 58 Pa. Cons. Stat. § 3218; see also CO SB 088, introduced unsuccessfully Feb. 16, 2012.
[43] For example, Boulder County, Resolution No. 2012-16 (Feb. 2, 2012); Colorado Springs, Steve Bach, Mayer of Colorado Springs, "Memorandum on Administration of the Use of Regulations Set Forth in Chapter 7, City Code," (Nov. 28, 2011); the City of Erie, Ord. No. 09-2012 (Mar. 7, 2012); and the city of Longmont, Ord. No. O-2012-18 (Dec. 20, 2011)—all enacted temporary moratoria on applications for oil and gas development.
[44] For a recent report that surveys state shale gas regulation and similarly finds significant variations among them, see Resources for the Future, "A Review of Shale Gas Regulations by State," http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx.

develop and elaborate best practices[45] to control and/or mitigate some of the environmental impacts associated with unconventional gas development. Some of these corporate practices go beyond existing regulation and some have served as the basis for new regulations.[46] Although it is impossible to predict the precise mix of future regulation, it is likely that additional regulations will be adopted and implemented as unconventional gas development proceeds. These could affect the costs of producing unconventional gas, but without basin- and company-specific data, it is not possible to determine the amount of additional compliance costs associated with any particular regulatory scenario. This is an important area for future research.

This chapter examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development.[47] Specifically, this chapter focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well construction standards, "green" or "reduced emission" completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities. The goal of the research was to identify changes and trends in the governing legal frameworks across the different basins, as well as key challenges going forward. Specific attention is given to regulatory uncertainty, fragmentation, gaps, and redundancies associated with the proliferation of new rules and regulations at multiple levels, as well as the implications of shifting public perception and support for gas development across various jurisdictions.

Due to time constraints, it was not possible to examine all impacts associated with gas development and corresponding regulatory responses. Key areas for future research include, for example, regulations aimed at reducing the risk of surface spills of acids and chemicals used in hydraulic fracturing, storm-water controls, open-pit requirements, and mitigation measures for truck traffic. Beyond the scope of this report is a complete discussion of the environmental and public health risks posed by unconventional gas development and an analysis of the extent to which the current regulatory and statutory regimes reduce such risks, or the extent to which voluntary implementation of best practices fill any gaps remaining.

The chapter focuses on six unconventional U.S. basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming. As Table 4 illustrates, each of these basins is marked by distinct resource, geologic, and hydro-geologic characteristics, and each has had different historical and contemporary

[45] The term *best practices* used here has the same meaning as that used by the SEAB in that it refers to "improvements in techniques and methods that rely on measurement and field experience" (SEAB 2011a). Best practices are not static, but rather, continuously evolving, as evidenced by the rapid changes in technologies related to stimulation techniques, methane capture, and water recycling.

[46] See, for example, green completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. EPA specifically cited industry's voluntary use of green completions in promulgating recent federal standards to limit air pollution from new and modified stationary sources in the Crude Oil and Natural Gas Production Category (EPA 2012c).

[47] Statutes applying uniquely to federal lands or actions, such as the Federal Lands Policy and Management Act, National Environmental Protection Act, and Endangered Species Act, are not discussed. For a more complete description of the federal framework that applies to unconventional gas development, see EPA 2000 and Kurth 2010.

experiences with oil and gas development. Accordingly, unconventional gas development in each of these basins and jurisdictions poses a distinct set of environmental issues, and it is the subject of a different mix of state and local regulation.

Table 4. Description of Shale Plays and Basins Studied

Primary Designation	Secondary Designation	Hydrocarbon Resources	Interest for Study	Production Characteristics
Barnett Shale Play	District 5, North Texas	Mostly dry gas, shale	Original shale gas basin, history, water stressed, near urban areas	6,000–8,500 feet deep
Eagle Ford Shale Play	Oil Producing Counties, South Texas	Oil, NGLs and gas, shale	High activity, resource diversity, water stressed	Oil 4,000–8,000 feet, NGLs/gas 8,000–12,000 feet deep, average thickness 450 feet
Haynesville Shale Play	DeSoto Parish, Louisiana	Mostly dry gas, shale	Second-largest shale gas reserves in U.S., active production	10,500–13,000 feet deep, high temperature and pressure
Marcellus Shale Play	Susquehanna River Basin, Ohio River Basin, Pennsylvania	Mostly dry gas, shale	Rapidly growing, diverse, area of significant public attention	5,000–7,000 feet deep, 100–500 feet thick, largest shale gas reserves in U.S.
North San Juan Basin	La Plata County, Colorado	Coal-bed methane	Colorado regulations, distinct risks due to CBM production	Fruitland formation, 550–4,000 feet deep
Upper Green River Basin	Jonah Field, Pinedale Anticline Wyoming	Mostly dry gas, tight sands	Active production, ozone nonattainment	Vertical wells, 8,000–11,000 feet deep in tight sands

This chapter also examines recent actions by local governments to ban, delay, or regulate hydraulic fracturing or gas development; responses to such actions by state courts and legislatures; and the implications of these developments for the industry's social license to operate in specific parts of the country.

Lastly, this chapter identifies several important examples where companies have adopted measures that go beyond compliance—namely, "green" completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. In some cases, these best practices have become the basis for new regulations (e.g., "green" completions). In others, they continue as voluntary actions that fill gaps or go beyond existing regulatory frameworks (e.g., reuse of produced and flowback waters).

The major conclusions that emerge from this analysis are as follows:

- Although there is a trend toward more regulation at all levels of governance, there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks of regulatory fragmentation including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information between regulators at all levels of government and across jurisdictions—as well as increased transparency in the form of publicly reported and publicly available data from industry—will help ensure that regulations are coordinated and tailored to specific geographic and geologic characteristics. Appropriately designed regulations that reflect local conditions such as gas composition and geology reduce environmental risks and ensure more efficient resource recovery.
- Compliance monitoring and enforcement actions vary significantly across states, with significant implications for the efficacy of regulations, as well as public confidence in the ability of state regulators to ensure that development proceeds safely. Public disclosure of violations, enforcement actions, and company compliance would bring greater transparency and accountability to an industry that, by its nature, poses unique compliance and enforcement challenges due to the disparate and often remote location of facilities and its rapid development in recent years. It would also provide an opportunity to highlight the compliance records of leading companies that have demonstrated a commitment to safe natural gas production.
- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. Ongoing consolidation in the industry could lead to more widespread adoption of best practices across the industry. However, additional implementation of beyond-compliance measures is unlikely to lead to less regulation given limited public acceptance of the concept of self-regulation in the industry. In some instances, the implementation of best practices may serve as the foundation for future regulation (Efstathiou 2012), which, in turn, could serve to level the playing field among producers and may help restore public trust in areas of the country where unconventional gas development has been controversial.
- There is a need for basin- and company-specific data to analyze the extent to which implementing beyond-compliance measures or additional regulation will affect the cost of producing natural gas and, by extension, the supply of gas to the electric power sector.[48] This study was not able to collect such data (see Chapter 4), but this will be a focus of a potential follow-up study.
- Notwithstanding the challenges of regulatory fragmentation, different state and local approaches to regulating unconventional natural gas development provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and process. Colorado, for example, recently implemented landmark legislation

[48] A recent report estimates that the application of 22 "Golden Rules" for shale gas development could add about 7% to the overall drilling and completion costs on a per well basis (IEA 2012). Assuming today's costs and prices are roughly equivalent, 7% added costs in the U.S. would amount to roughly an additional $0.25/MMBtu produced.

with the support of multiple constituencies, including the natural gas industry and environmental groups, that resulted in a dramatic shift in the state's electric power sector away from coal toward greater use of natural gas and renewable energy (see Chapter 1 for a discussion of the potential climate benefits associated with using natural gas as opposed to coal as a feedstock for electricity generation). This could not have happened absent an initial effort to revise the state's oil and gas laws. New York's decision to undertake a detailed and extensive study of the impacts associated with high-volume hydraulic fracturing has led to development of some of the most comprehensive rules in the country. It remains to be seen whether, if adopted, they alleviate public concerns regarding the risks associated with unconventional gas development .

2.2 Federal Legal Framework

The major federal environmental laws provide the overarching framework for regulating many of the environmental impacts associated with unconventional natural gas development. Some of these laws, however, contain explicit exemptions or definitional exclusions for natural gas development, resulting in a significant role for state regulation in key areas such as waste management, disclosure of chemicals used in hydraulic fracturing and releases, and well construction standards other than for underground-injection disposal wells. This section analyzes the federal regulatory framework governing air, water, and waste issues associated with unconventional gas development. It focuses on the scope of federal regulation, the extent to which state law fills any gaps left open by the federal regulatory scheme, recent legislative proposals and rule-makings, key trends, and the implications of a changing federal regulatory framework for future development.

2.2.1 Overview and Key Trends

Federal laws governing the air, water, and waste impacts associated with the production of unconventional natural gas vary in terms of scope. EPA has broad authority to regulate emissions of air pollutants, including GHGs, direct and indirect discharges of wastewater from point sources, and the injection of produced water into underground injection wells for disposal.[49] The federal government, primarily through the U.S. Department of the Interior, also has authority over the development of natural gas on federal and tribal lands. Federal oversight over the management of hazardous and solid wastes, reporting and disclosure requirements of toxic or hazardous releases, and the process of hydraulic fracturing itself is much more limited—and, in some cases, it is entirely absent given specific exemptions and definitional exclusions under certain federal laws such as the Resource Recovery and Conservation Act; the Comprehensive Environmental Response, Compensation and Liability Act; and the Safe Drinking Water Act.

Some federal exemptions have been the focus of proposed legislation in past and current Congresses,[50] and efforts to repeal or narrow these exemptions are likely to continue. Congress also recently requested that EPA conduct a study evaluating the potential impacts of hydraulic fracturing on drinking water (EPA 2011e). Depending on the results of this study, the first of

[49] An exception to this is section 112(n)(4) of the Clean Air Act, which contains prohibitions on the aggregation of hazardous air pollutant emissions from certain gas wells and other equipment that constrain regulation of such sources (42 U.S.C. § 7412(n)(4)).
[50] See, for example, The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.

which are due out sometime in 2012 with additional results in 2014, EPA may assume a more active role in regulating hydraulic fracturing—including reconsidering its determination that certain natural gas wastes are not hazardous, and recommending changes to the statutory framework that applies to the process of hydraulic fracturing. In the meantime, the states continue to play an important role in regulating various aspects of hydraulic fracturing. The extent to which states have filled gaps left open by federal regulation is discussed in Section 2.3.

The trend at the federal level is toward more regulation. As discussed in more detail below, a number of federal rules related to gas development have been finalized, proposed, or announced recently in response to increased development, and there have been repeated calls for new legislation. Taken together, these efforts indicate a growing interest in hydraulic fracturing and unconventional gas development at the federal level and the likelihood of additional federal regulation, and possibly legislation regarding the removal of certain exemptions in existing statutes, as has been proposed in the past.

2.2.2 Hydraulic Fracturing

The process of hydraulic fracturing, other than when diesel fuel is used, is expressly excluded from federal regulation under the Safe Drinking Water Act's Underground Injection Control program.[51] Were hydraulic fracturing not specifically excluded from the definition of *underground injection*, the natural gas industry would be required to comply with certain federal well construction, operation, and closure requirements, as well as disclosure requirements. This has been, and likely will continue to be, a source of controversy because numerous bills were introduced in 2009, 2010, and 2011 to bring the process of hydraulic fracturing within EPA's control (Martin et al. 2010).[52] Although prior attempts have all been unsuccessful, it is likely that similar legislation will be introduced in the future (Hammer and VanBriesen 2012). Additional pressure for greater federal regulation could also come as a result of EPA's hydraulic fracturing study if it concludes that the process of injecting fluids underground during hydraulic fracturing increases the risk of groundwater contamination.[53]

EPA recently published draft guidance governing the use of diesel in hydraulic fracturing fluids that includes requirements for diesel fuels used for hydraulic fracturing wells, technical recommendations for permitting, and a description of diesel fuels for EPA underground injection control permitting (EPA 2012b). As proposed, this guidance only applies where the EPA is the permitting authority. States with primacy over the Underground Injection Control program, which include Texas, Louisiana, and Wyoming, are not required to follow the guidance (Figure 11).

[51] 42 U.S.C. § 300h(d)(1)(B)(ii) (2005).
[52] The most recent efforts being The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.
[53] An area of ongoing controversy and debate is whether or not the process of hydraulic fracturing poses a greater risk of subsurface water contamination than other aspects of development that are common to all types of oil and gas production such as surface spills, impoundment failures, and faulty well construction (Groat and Grimshaw 2012; Hammer and VanBriesen 2012; Jones 2011).

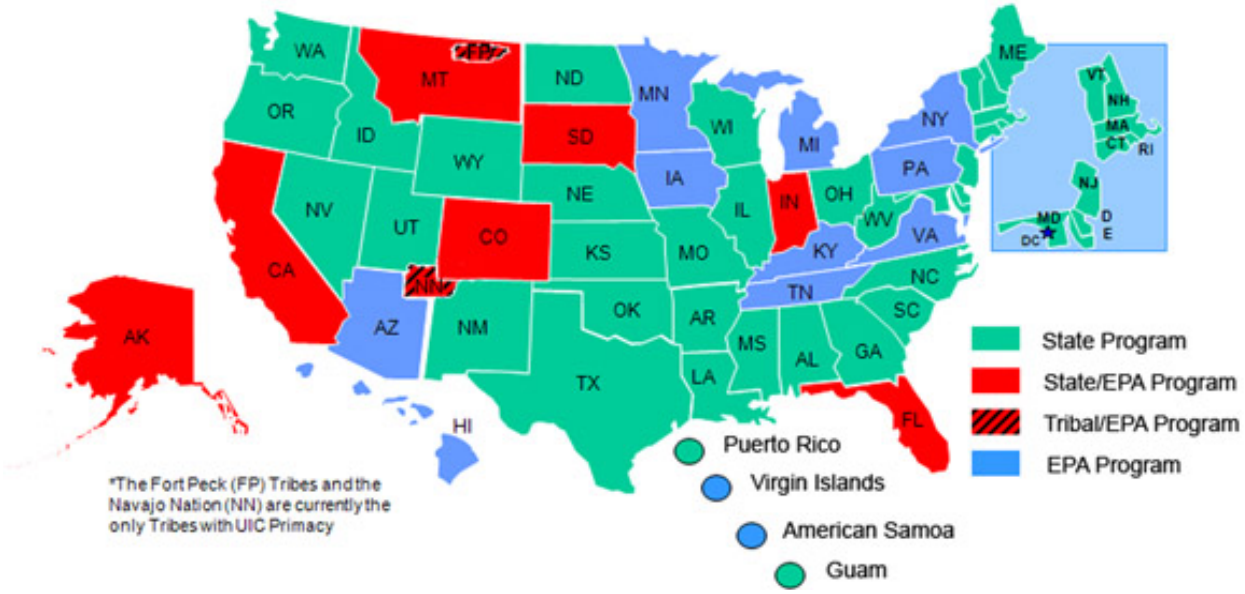

Figure 11. EPA map of Underground Injection Control Program Primacy[54]

Given the limited federal role in this area, states are the primary regulators of well construction standards that apply to the process of hydraulic fracturing (see Section 2.3.3 below).[55] However, with respect to natural gas development on federal lands, the Bureau of Land Management (BLM) recently proposed a rule that would require the use of cement bond logs on surface casing and mechanical integrity testing prior to hydraulic fracturing to improve well integrity (BLM 2012). Both EPA's proposed diesel fuel guidance and BLM's proposed well construction standards help to provide greater regulatory certainty to the production of natural gas. However, state regulations remain central given the limited applicability of the EPA guidance and BLM standards.

2.2.3 Water Quality

As reported in various news media, for the public, some of the most prominent environmental concerns associated with unconventional gas development that have emerged are adverse impacts to groundwater and surface water resources. The major federal statutes protecting water quality—the Clean Water Act and the Safe Drinking Water Act—apply to various aspects of unconventional gas development, with different approaches and experiences in different parts of the country.

The Clean Water Act prohibits the unauthorized discharge of wastewater into the surface waters of the United States from point sources. Discharges may be authorized by permits issued under the National Pollutant Discharge Elimination System, whose permits require industry-specific, technology-based limits and water-quality-based effluent limitations. The latter vary depending

[54] EPA, "UIC Program Primacy," http://water.epa.gov/type/groundwater/uic/Primacy.cfm.
[55] Well integrity is essential not only to reduce risks associated with hydraulic fracturing, but also, with the entire universe of down-hole activities (i.e., wells that are not hydraulically fractured also pose a risk to surface and subsurface water sources if not properly cased, cemented, and monitored).

on local conditions because they are tailored to protect specific designated uses of surface waters.

EPA has established two national effluent limitation guidelines that apply to unconventional gas wells. The first completely prohibits the discharge into navigable waters of natural gas wastewater pollutants, such as produced water, drilling muds, or drill cuttings from any source associated with oil and gas production, field exploration, drilling, well completion, or well treatment, located east of the 98th meridian. [56] The second guideline applies to operators west of the 98th meridian and allows the discharge of produced water only if it may be used beneficially for agricultural or wildlife propagation.[57]

Indirect discharges to publicly owned treatment works (POTWs) and discharges from centralized waste treatment facilities (CWTs) are also subject to the Clean Water Act framework. However, EPA has not promulgated pretreatment standards that apply to the discharge of shale and coal-bed methane (CBM) wastewater to POTWs, leaving a gap in the federal framework that has been the source of considerable controversy. Discharges from CWTs are subject to federal technology-based standards, although these standards do not contain limits for all of the pollutants contained in natural gas wastewater—in particular, bromide or total dissolved solids. [58]

EPA's decision under the CWA to prohibit direct discharges of drilling wastewater to surface waters in states east of the 98th meridian, combined with limited injection well capacity in that part of the country (see Chapter 4, discussing the fact that Pennsylvania has only eight Class II underground disposal wells), has resulted in increased use of indirect discharges to POTWs and CWTs. Many POTWs, however, are not designed or permitted to handle the volumes and types of wastewater produced from the booming shale gas industry (Urbina 2011). In Pennsylvania, insufficient treatment capacity for shale gas wastewater resulted in contamination of state waters—in particular, elevated levels of total dissolved solids, organic chemicals, and metals (EPA 2011c)—prompting the state to request operators to voluntarily cease sending shale gas wastewater to older POTWs and also resulting in new state limits for total dissolved solids and chlorides[59] (EPA 2011b).

EPA has announced its intent to develop pretreatment standards for discharges of CBM and shale wastewater in 2013 and 2014, respectively (EPA 2011a). These standards should bring certainty to this area, reduce the likelihood that treated wastewater discharges from POTWs will contaminate surface waters, and improve public confidence in the ability of natural gas development to be done safely. Depending on how these standards are set, they may also drive the development of technologies to recycle and reuse wastewater. If, for example, EPA adopted a "no discharge" or otherwise stringent limit, operators would need to rely more heavily on other

[56] Onshore Subcategory Guidelines, 40 C.F.R. § 435.30 (2012). The 98th meridian runs through North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. Direct discharges of produced water west of the 98th meridian are permitted provided the water does not exceed specified parameters for oil or grease and can be used for agricultural or wildlife propagation. *Id*. § 435.50.
[57] *Id*. § 435.50. Produced water has an effluent limitation of 35 mg/L of oil and grease. *Id.* § 435.52.
[58] See 33 U.S.C. § 1317 (2012); EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.
[59] 25 Pa. Code § 95.10(b)(3)(iv)-(vi).

forms of wastewater disposal such as underground injection or recycling. In parts of the country, such as Pennsylvania, where underground injection wells are limited, a "no discharge" standard could result in significantly more recycling and reuse—especially if doing so is less costly than transporting wastewater out of state for injection.

As noted above, in addition to complying with national effluent limitation guidelines, POTWs and CWTs discharging wastewater must comply with numeric limits on certain pollutants designed to ensure that discharges do not impair the designated uses of surface water bodies. Although EPA has established guidance for water-quality criteria for some natural gas wastewater, it does not cover all pollutants contained in wastewater (Hammer and VanBriesen 2012).[60] Additional guidance from EPA would provide a certain degree of certainty and more uniform protection because states rely on EPA guidance when adopting water-quality criteria, and EPA retains authority to promulgate its own criteria if it determines a state has failed to adopt adequate standards of its own. Notably, EPA recently signaled its intent to update water-quality criteria for chloride, which is arguably outdated because it was established well before the recent shale gas boom (EPA 2011b).

2.2.4 Hazardous and Solid Wastes

2.2.4.1 Management of Waste

Subtitle C of the Resource Conservation and Recovery Act imposes stringent "cradle-to-grave" requirements that apply to the generation, transportation, treatment, storage, and disposal of hazardous waste.[61] Most of the wastes associated with natural gas drilling, however, are exempt from the Resource Conservation and Recovery Act's program for hazardous wastes. Specifically, drilling fluids, produced water, and other wastes "intrinsically related" to the production and development of natural gas are exempt from Subtitle C hazardous waste requirements.[62] As a result, management of these wastes is primarily a matter of state law. Non-exempt wastes, such as unused fracturing fluids, waste solvents, and used hydraulic fluids, are subject to the Resource Conservation and Recovery Act and may be covered under Subtitle C if they exhibit hazardous characteristics or are specifically listed as hazardous wastes. Exempt wastes not regulated as hazardous are subject to state rules because EPA has not promulgated regulations governing the management of oil and gas solid waste (NRLC 2012). Although this allows for regulation to be tailored to local geologic or hydrologic conditions, it also creates greater horizontal fragmentation, uncertainty, and the potential for inadequate state rules. See the discussion in Section 2.3.5.2 and Table 28 in Appendix C comparing state rules for produced water.

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[60] The current guideline only applies to certain pollutants such as chloride, oil and grease, suspended solids, turbidity, and nitrates. See EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.

[61] 40 C.F.R. pt. 260 et seq. Specifically, generators must ensure and fully document that their hazardous waste is properly identified, managed, and treated prior to recycling and disposal. They must comply with requirements for training and emergency arrangements (including having an emergency coordinator and testing and maintaining emergency equipment) and must track the shipment and receipt of their waste. Additionally, a hazardous waste generator is limited in the amount of waste it can accumulate. A large-quantity hazardous waste generator (one that generates 1,000 kg or more of hazardous waste per month) must move all the waste it generates off site within 90 days; a small-quantity generator must move all its waste off site within 180 days. See EPA, Regulations Governing Hazardous Waste Generators, at III-41-47, http://www.epa.gov/osw/inforesources/pubs/orientat/rom33.pdf.

[62] In addition, EPA has determined that produced water injected for enhanced recovery is not waste subject to the Resource Conservation and Recovery Act and is therefore exempt from regulation under the statute. However, produced water stored in above-ground impoundments is subject to state law (EPA 2000).

Some observers have called for the federal regulation of natural gas waste as hazardous under Subtitle C of the Resource Conservation and Recovery Act (Hammer and VanBriesen 2012). EPA has not signaled its intent to reverse its decision regarding the management of natural gas waste; however, it remains a possibility, and may turn, in part, on the outcome of EPA's study on hydraulic fracturing.

2.2.4.2 Liability for Releases of Hazardous Substances

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as "Superfund," imposes strict liability for releases of hazardous substances on owners and operators of "facilities" (which include natural gas production sites), as well as arrangers and transporters of hazardous substances. The definition of *hazardous substance* under CERCLA, however, is limited in its application to crude oil, petroleum, and natural gas.[63] Specifically, petroleum and crude oil—as well as hazardous substances that are normally mixed with or added to crude oil or crude oil fractions during the refining process—are not considered hazardous substances under the so-called "petroleum exclusion."[64] Also excluded from the definition of hazardous substances are natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel.[65] Releases of other hazardous substances from natural gas drilling operations, such as hydraulic fracturing fluids containing hazardous chemicals, are subject to standard CERCLA liability. Thus, federal law provides for some potential CERCLA liability for natural gas operators, but the scope of such liability is narrow. Moreover, even though some states, such as Colorado, Texas, and Pennsylvania, have adopted their own environmental cleanup legislation, these states have all retained the federal definition of hazardous substances.[66]

2.2.4.3 Reporting of Hazardous or Toxic Chemical Releases

Federal law imposes few reporting requirements on operators of natural gas production facilities for the release of hazardous or toxic chemicals. Under CERCLA, operators must report releases of hazardous substances above reportable quantities, although the same definition of hazardous

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[63] 42 U.S.C. § 9601(14).

[64] *Id*. Discharges of oil from certain production facilities may be subject to the Clean Water Act's Oil Pollution Prevention Program, which requires covered facilities to prepare and implement Spill Prevention Control and Countermeasures to prevent oil discharges (EPA 2000).

[65] *Id*. at § 9601(14).

[66] New York has a state law mirroring CERCLA, including a state Superfund to pay for site cleanup when no responsible party can be identified or the responsible party has inadequate funds for the cleanup. The state requires reporting and cleanup of petroleum spills within the state through its spill response program and its Brownfield and Superfund laws. New York's Brownfield regulations still exclude "natural gas, natural gas liquids, liquefied natural gas, synthetic gas usable for fuel, or mixtures of natural gas and such synthetic gas" from the definition of "hazardous waste" and "contaminant," thereby removing natural gas from the law's application. New York Department of Environmental Conservation, *Chemical and Petroleum Spills*, http://www.dec.ny.gov/chemical/8428.html; see also New York General Remedial Program Requirements, N .Y. Comp. Codes R. & Regs. title 6, § 375-1.2(w)(1). Pennsylvania operates within the CERCLA framework, but also has separate state legislation to fill in gaps in CERCLA. Pennsylvania Department of Environmental Protection, *Superfund*, http://www.portal.state.pa.us/portal/server.pt?open=514&objID=589587&mode=2. This state legislation retains the exclusion for natural gas and petroleum from the definition of "hazardous substance" and "hazardous waste." Pennsylvania Hazardous Sites Cleanup Act, 756 Act 1988–108, sec. 103 (definitions of "hazardous substance" and "hazardous waste"). Colorado has a statute on hazardous waste cleanup that essentially authorizes the State to cooperate with the federal government in the implementation of CERCLA. Colorado Hazardous Waste Cleanup Act, C.R.S. § 25-16-101. The Colorado statute adopts the CERCLA definition of hazardous substance, thereby excluding petroleum and natural gas. *Id*.

substance applies here as it does to the statute's liability scheme.[67] Oil and gas operators are not required to report annual releases of toxic chemicals under rules promulgated pursuant to the Emergency Planning and Community Right-to-Know Act's Toxics Release Inventory or to disclose the chemicals used in hydraulic fracturing to members of the public or regulators due to the exemption of hydraulic fracturing under the Safe Drinking Water Act.[68]

Natural gas operators are subject to requirements to report or disclose chemicals stored on-site, although these are limited. Owners and operators of storage facilities holding in excess of 10,000 pounds of any hazardous chemical must submit chemical inventory information to state and local emergency response and fire officials.[69] In addition, under the Emergency Planning and Community Right-to-Know Act and regulations promulgated pursuant to the Occupational Safety and Health Act, natural gas operators using products containing hazardous chemicals must maintain material safety data sheets on site, and must make them available to state and local emergency response and fire officials, subject to trade secret protection.[70]

States are increasingly filling the gap related to public disclosure of the chemicals used in hydraulic fracturing fluids. As discussed in more detail below, there is a clear trend toward public disclosure of all chemicals, not just those listed on material safety data sheets (Table 23 in Appendix C). This trend is evident at the state level and in the recently proposed BLM rule, which would require disclosure for production on federal and tribal lands (BLM 2012).

In terms of other reporting requirements, EPA has announced an intention to gather data on the aggregate amounts of exploration and production chemical substances and mixtures used in hydraulic fracturing. It is unclear to what extent these regulations will fill any of the gaps that remain in federal reporting requirements. But EPA has signaled an intent to avoid vertical fragmentation by framing its proposal as one that "would not duplicate, but instead complement, the well-by-well disclosure programs of states"(EPA 2011d).[71] In addition, states may adopt their own reporting requirements for releases.[72]

2.2.4.4 Disposal of Produced Water

As noted above, states primarily regulate waste disposal. One exception is the disposal of produced water into Class II underground injection wells, which is regulated by EPA's Underground Injection Control program, although states with primacy issue the actual permits.[73] Some states have recently raised concerns regarding the disposal of produced water into Class II wells, in response to evidence linking such disposal to earthquakes (Niquette 2011; Hammer and VanBriesen 2012). For example, nine earthquakes were recorded recently in Youngstown, Ohio,

[67] 42 U.S.C. § 11004 (2012). EPA also requires operators to disclose "the source and analysis of the physical and chemical characteristics" of chemicals used in underground well stimulation permit applications (EPA 2008b).
[68] 42 U.S.C. § 11023(b) (2012) (EPA 2000; Wiseman 2010).
[69] 42 U.S.C. § 11022 (2012).
[70] *Id.*; 29 C.F.R. §1960.34(b)(6) (2012). Disclosure to the public of material safety data sheets is available upon written request.
[71] Letter from Stephen A. Owens, Assistant Administrator to Ms. Deborah Goldberg, Earthjustice re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, (Nov. 23, 2011), http://www.epa.gov/oppt/chemtest/pubs/EPA_Letter_to_Earthjustice_on_TSCA_Petition.pdf.
[72] See, for example, COGCC R. 906(b)(3) (requiring oil and gas producers to report spills that threaten to impact waters of the state).
[73] 40 C.F.R. § 144.6 (2010).

all of which were located within a half mile of an injection well, and all of which occurred within the first 11 months of injection of produced water into the well (Niquette 2011). Although scientists have yet to determine the cause of recent earthquakes, there have been instances in the past where injection wells used by other industries have been linked to earthquakes. (Holland 2011). This indicates that any causal relationship between underground injection of waste and seismic activity is not an impact unique to the natural gas industry. However, the volume of produced water associated with the significant increase in unconventional gas development across the country may place an increased strain on underground injection well capacity, especially in those areas where other disposal methods are less available. In addition to potentially causing earthquakes, underground injection of large amounts of produced water can increase the risk of subsurface contamination due to leaky wells.[74] Some suggest EPA should require the disposal of produced water into Class I, rather than Class II, wells because the former are subject to more rigorous standards on well construction, operation, and closure (Hammer and VanBriesen 2012). This will likely be an area of continuing public scrutiny and could be subject to additional state or federal regulation in the future.[75]

2.2.5 Air Quality

EPA has broad authority under the Clean Air Act to promulgate rules to reduce air pollution from natural gas sources. The most prominent air-quality issues associated with unconventional gas development include emissions of ozone precursors, VOCs and oxides of nitrogen, various hazardous air pollutants, and methane, all of which are subject to the basic Clean Air Act framework. Concentrated natural gas development has led to elevated ozone levels in rural parts of Wyoming and Utah where little other industrial activity occurs (Fruedenthal 2009; Streater 2010), and has also contributed to ozone pollution in more urban and industrial areas such as the Dallas Fort-Worth metropolitan area (Armendariz 2009). In 2012, the EPA responded to exceedances of the national health-based ambient air quality standards (i.e., National Ambient Air Quality Standards) for ozone in the Upper Green River basin by classifying the basin—for the first time—as in nonattainment with the 2008 8-hour National Ambient Air Quality Standard for ozone. [76] This listing could result in the state adopting more stringent rules to reduce emissions of VOCs and/or NO_x from natural gas sources in the basin to meet its Clean Air Act obligations.

Until recently, EPA has exercised its Clean Air Act authority with respect to natural gas production by focusing on a select number of natural gas production sources such as new and modified gas-processing plants, glycol dehydrators, crude oil and condensate storage vessels, and select engines used in the natural gas supply chain (e.g., engines used to power compressors). Most of these rules were implemented long before the unconventional natural gas boom occurred.

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[74] Personal conversation with Mark Williams, Professor of Geography and Fellow, INSTAAR, University of Colorado-Boulder, April 25, 2012.

[75] Notably, the Ohio Dept. of Natural Resources has enhanced Class II well permitting requirements, requiring seismic tests prior to construction of the well and ongoing monitoring, among other protections. Ohio Dept. of Natural Resources, Class II Disposal Well Reforms/Youngstown Seismic Activity Questions and Answers, http://ohiodnr.com/downloads/northstar/YoungstownFAQ.pdf.

[76] See EPA State Final Designations, April 2012 and May 2012, http://www.epa.gov/ozonedesignations/2008standards/state.htm.

In April 2012, however, EPA issued revised New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) (EPA 2012c)[77] that update existing standards and apply new requirements to previously unregulated sources. Specifically, EPA's new rules add requirements limiting VOCs and hazardous air pollutants emitted from completions and recompletions of hydraulically fractured natural gas wells (known as the "reduced emission completion" or "green completion" requirement), pneumatic devices, storage vessels, compressors, and "small" glycol dehydrators located at major sources of hazardous air pollution (EPA 2012c). Certain of these requirements result in the co-benefit of reducing methane because, in many cases, controlling VOCs also results in methane reductions (EPA 2012c). In addition, EPA updated standards and limits that apply to gas processing plants and large glycol dehydrators located at major sources of air pollution (EPA 2012c).

The revised NSPS and NESHAPS regulations provide a national floor that addresses unevenness in state air requirements. For example, EPA's new green completion requirements impose a level of uniformity across states with respect to control of ozone precursors and methane from unconventional natural gas development, as illustrated in Table 29, Appendix C, which compares green completion requirements. These new requirements implement one of the key recommendations of the SEAB, that EPA "adopt rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations[.]" (SEAB 2011a, 2011b). Prior to EPA's adoption of the reduced emission completion requirement, many operators voluntarily used green completion practices to maximize resource recovery, illustrating how certain best management practices can serve as the foundation for future regulation (Efstathiou 2012, EPA 2012c).

In August 2012, EPA released a rule that requires capture or high-efficiency combustion of associated gas produced from crude oil wells in the Fort Berthold Indian Reservation in North Dakota.[78] The rule applies during well completions and re-completions, the separation phase of oil production, and during production. Specifically, the rule requires that operators control emissions of VOCs by 90% during well completions or re-completions or perform a reduced-emission completion, route all produced gas and gas emissions to a control device capable of at least a 90% control efficiency upon production, and, within 90 days of production, capture all associated gas or route it to a control device capable of 98% control efficiency.

In September 2012, natural gas producers will also begin reporting GHG emissions from facilities subject to EPA's Mandatory Greenhouse Gas Reporting rule. As required by that rule, natural gas facilities that emit 25,000 metric tons of CO_2e or more of GHGs will be required to report GHG emissions (EPA 2010). Operators have been granted a grace period to use less rigorous measurement practices initially, but the data collected will provide much greater certainty regarding actual methane leakage rates. Precise information regarding methane emissions from natural gas systems is essential to resolving discrepancies among life cycle assessments, such as those discussed in Chapter 1.

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[77] U.S. E.P.A, Final Rule, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf.

[78] EPA, "Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), ND" 77 Federal Register 48878 (August 15, 2012).

Despite EPA's broad authority to implement clean air measures, states retain significant room to regulate. States with delegated programs may implement standards more stringent than federal law, unless prohibited by state law from doing so. States retain authority to regulate sources and air pollutants not covered by existing federal rules, and states may also impose more stringent rules than federal to meet National Ambient Air Quality Standards for criteria pollutants.

2.3 State Statutory and Regulatory Frameworks

Against this backdrop of federal environmental regulation, state and local governments have adopted numerous laws and regulations governing unconventional gas development, with considerable variation across different states, especially regarding the handling of waste and wastewater, construction of wells other than underground injection disposal wells, and baseline water-monitoring requirements. States also have exclusive jurisdiction over water withdrawals, other than those occurring on federal lands,[79] and over various land-use controls such as setback requirements and zoning, some of which have been delegated to local governments. As discussed above, although a number of federal rules apply to protecting water and air resources, states also retain authority to develop more stringent standards and to regulate impacts or sources not covered by federal law. Prior to EPA's recent revisions of the NSPS and NESHAPS, some states—notably Colorado and Wyoming—adopted air regulations that went beyond then-existing federal standards [80] (WY DEQ 2010), whereas New York has proposed a number of regulations to protect water sources and ensure safer waste management that go beyond federal and other state rules. Some states have increased inspection capacity to respond to the rapid increase in unconventional gas development; however, there is considerable variation in state inspection capacities and enforcement approaches.

This section analyzes the state regulatory frameworks governing air, water, waste, and compliance and enforcement issues associated with unconventional gas development in Colorado, Wyoming, New York, Texas, Louisiana, and Pennsylvania. It focuses on the extent to which state law fills any gaps left open by the federal regulatory scheme, as well as on key trends, differences in the regulatory frameworks across the different basins, compliance monitoring, and enforcement capabilities and actions.

2.3.1 Overview and Key Trends

The wide variation in state approaches to the regulation of unconventional natural gas development reflects differences in resource characteristics (e.g., dry versus wet gas, deep shale versus shallow CBM), geology, and hydrology, as well as different experiences with oil and gas development and different approaches to and preferences for environmental protection. Across the country, states have responded to hydraulic fracturing in very different ways. Vermont, for example, recently enacted legislation banning hydraulic fracturing in the state.[81] New York, as noted, has imposed a temporary moratorium on drilling as it develops regulations.[82] Recently, the Cuomo administration announced that it will undertake a public health study of the potential impacts of hydraulic fracturing and re-start the rule-making process prior to issuing any new

[79] See, for example, the proposed BLM rule, which requires operators to identify the source of water to be used in fracturing in order for the BLM to determine impacts and mitigation measures, if needed (BLM 2012).
[80] COGCC R. 805(b).
[81] H 464 (enacted May 16, 2012).
[82] 9 N.Y. Comp. Codes R. & Regs. tit. 9, § 7.41.

regulations.[83] A number of states (specifically Colorado, Wyoming, and Pennsylvania) have revised their oil and gas rules extensively—at least once, and in some cases, continue to do so—to respond to the uptick in unconventional resource development; Louisiana and Texas have engaged in much more limited revisions. New York, as noted above, is in the process of revising its regulations. Louisiana, Pennsylvania, and Colorado have all recently submitted their hydraulic fracturing rules to the State Review of Oil and Natural Gas Environmental Regulations for review, whereas Wyoming and Texas have not (and New York has not yet finalized its high-volume hydraulic fracturing regulations) (STRONGER, 2010; STRONGER 2011a; STRONGER 2011b). Pennsylvania and Louisiana significantly increased the number of oil and gas inspectors in response to increased development, whereas resources in other states appear quite limited. Data are limited and more research is needed, but there appears to be very little consistency in the ways that states record, respond to, and enforce against violations—including substantial ranges in penalties and the number of violations that result in enforcement actions. Areas highlighted as meriting additional attention from state regulators are improved transparency regarding compliance monitoring, company compliance histories, and enforcement actions.

Different regulatory approaches by states can lead to uncertainty, gaps, and/or redundancies in mitigating some of the more significant environmental risks associated with unconventional gas development and ensuring overall compliance. But they can also provide a source of policy innovation because different jurisdictions experiment with new approaches to regulating various aspects of shale gas development. An example is New York's proposal to require operators to document that, compared to available alternatives, chemical additives used in hydraulic fracturing fluids exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment.[84] For this reason, it is important that state regulators and policy makers share information and lessons learned with other states. National standards provide a baseline or floor in some areas, such as national effluent limitation guidelines for wastewater discharges and EPA's recent NSPS and National Emission Standards for Hazardous Air Pollutants. However, a permanent feature of the regulatory landscape appears to be the uneven and varied nature of state and local regulation and enforcement regarding most other aspects of shale gas development.

Despite the variety in specific state and local regulations and enforcement, some important trends are evident. All states reviewed here recently revised their oil and gas rules and/or laws to respond specifically to the increase in unconventional resource development. Colorado, New York, Wyoming, and Pennsylvania recently undertook extensive reviews and revisions of their laws and regulations that , in some cases, resulted in considerably more comprehensive—and in many instances, protective—rules than those in Louisiana and Texas. For example, Colorado and Wyoming have been leaders in rules to reduce emissions of ozone precursors, and New York and Pennsylvania are leaders in laws regarding measurement and public disclosure of water sources and waste. See Table 22, Appendix C, for a general description of revisions to state oil and gas laws.

[83] Danny Hakim, "Shift by Cuomo on Gas Drilling Prompts Both Anger and Praise," *New York Times,* Sept. 30, 2012.
[84] N.Y. Comp. Codes R. & Regs. tit. 6, §560. 3.

There is a clear trend in all of the states studied toward greater transparency—such as mandatory public disclosure of chemicals used in hydraulic fracturing and the composition of wastewater, reporting of the amounts and sources of water used in hydraulic fracturing, and more rigorous well-construction standards, including notifications of hydraulic fracturing and well completions. A key recommendation of the SEAB Subcommittee (SEAB 2011a) was greater transparency, in the form of public disclosure of the chemicals, amounts, and sources of water used or produced during hydraulic fracturing, baseline water monitoring measurements, and reduction and measurement of air emissions. These activities have the potential to lead to better public understanding and acceptance of natural gas development.

All states covered in this study have added requirements that providers of fluids used in hydraulic fracturing and/or operators disclose the contents of most chemicals to the public. These requirements are in addition to, and go beyond, federal requirements that require operators to maintain material safety data sheets for certain hazardous chemicals stored on-site in threshold quantities, and to report releases of hazardous chemicals in threshold quantities.[85] In addition, all of the states covered in this study require operators to report the amount and, in most cases, the source of water used in hydraulic fracturing either to the public or state regulators.

Other areas of state regulation or interest include: baseline water-monitoring requirements; use of closed-loop drilling systems to contain waste, rather than open, earthen pits; reporting or reduction of emissions of air pollutants; standards to ensure well integrity; and more active involvement on the parts of local government over drilling activities.

State compliance monitoring and enforcement capacity varies considerably, although significant data limitations across the different states mean that any comparisons should be considered provisional. Based on available data, some states—notably Pennsylvania and Louisiana—recently increased state inspection capabilities to respond to increased development, whereas resources in other states appear quite limited. The methods that states use to track and report violations and enforcement actions also differ substantially—with some states, notably Pennsylvania, making violations and enforcement actions publicly available via online databases; other states, notably Colorado and Wyoming, have been criticized for a lack of transparency and limited public access to such information.[86]

Variation across states in substantive regulations, as well as compliance monitoring and enforcement capacity, can be explained by a number of factors. Some are legal, such as federal effluent limitation guidelines that differ across regions and state statutes limiting the amount of penalties that can be assessed for violations. Others reflect differences in local environmental conditions (e.g., elevated ozone levels in the Upper Green River basin and Denver metropolitan area, respectively, led Wyoming and Colorado to adopt air rules that went beyond then-existing federal requirements, forming the basis for some of EPA's new NSPS rules); geologic and hydro-geologic conditions (e.g., developing shallow CBM resources poses unique risks that deep shale does not)[87]; proximity of drilling to densely populated areas or sensitive environmental

[85] 42 U.S.C. § 11021-11022 (2006); 55 Fed. Reg. 30,632 (July 26, 1990).
[86] See, for example, Earthworks (2012b) and Soraghan (2011).
[87] See, for example, COGCC R. 608(b)(4).

areas (e.g., setback requirements and buffer zones)[88]; historical and contemporary experiences with oil and gas development; and preferences for environmental protection.

2.3.2 Water Acquisition

The regulation of water withdrawals is primarily a matter of state and local, rather than federal, law. The legal framework governing water rights differs from state to state, although there is some consistency along regional lines.[89] There is a clear trend toward requiring operators to identify the sources of water used, report the amount of water used in hydraulic fracturing, and provide for incentives to promote reuse of water used in hydraulic fracturing such as by recycling flowback waters or production fluids. All states require operators to report on the amount of water used for hydraulic fracturing, as does BLM's new proposed rule.[90] In addition, both New York and Pennsylvania require operators to provide for the reuse and recycling of flowback water or production fluids in water management plans or wastewater source reduction strategies. States also have begun to require minimum in-stream flow below points of water withdrawal and other measures to ensure that aquatic wildlife, water quality, and other water users will not be adversely affected.[91]

A handful of local governments also regulate some aspects of water acquisition. For example, Archuleta County, Colorado, requires operators in the North San Juan basin to submit a water management plan that includes a plan for disposal or reuse, projected water use, identification of the water source, and water availability (Archuleta 2010). The City of Fort Worth, Texas, requires operators to describe the water source proposed to be used for drilling in application for permits to drill.[92] As unconventional gas development expands in various parts of the country, it seems likely that more local governments will seek to get involved in regulating aspects of water acquisition.

For more information related to state and local regulation of water withdrawals, see Table 24, Appendix C, Water Acquisition Requirements.

2.3.3 Hydraulic Fracturing and Well Construction Standards

State well-construction standards vary considerably, which to a certain extent can be explained by differences in local geology. However, certain safeguards do not depend on differences in local conditions. Standards that have been recommended to increase well integrity include the use of state-of-the-art cement bond logs, pressure testing of casing, monitoring and recording bradenhead annulus pressure, and assurances that surface casing is run below all known underground aquifers to reduce the risk of drinking water contamination from fluid or gas

[88] See, for example, setback requirements in the Barnett Shale and New York's proposed buffer zones to protect sources of drinking water, Appendix C.
[89] The two most common doctrines governing water rights are the prior appropriation and riparian doctrines. The prior appropriation doctrine provides rights to continued use of water to those who first put water to beneficial use and is the predominant regime in most of the West (CDWR 2012; Groat and Grimshaw 2012). In a riparian water rights system, water rights are tied to the ownership of land adjacent to water resources.
[90] DOI, Bureau of Land Management, Proposed Rule "Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands", May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.
[91] See, e.g., 58 Penn. Stat. § 3211(m)(2).
[92] Fort Worth, Tex., Ord. No. 18449-02-2009.

migration (SEAB 2011b). Of the states reviewed, only Colorado and Louisiana require the use of cement bond logs.[93] New York has proposed to require the use of cement bond logs. All states except Wyoming require some kind of pressure testing of casing, although the specifics vary regarding the testing and circumstances requiring testing. Colorado is the only state that requires monitoring of annulus pressure with bradenhead (Texas requires all wells to be equipped with bradenhead, but only requires a pressure test in certain instances). All states require surface casing to be set below known aquifers, although the specific requirements vary. For specific requirements, see Table 25 in Appendix C.

2.3.4 Baseline Water-Quality Monitoring

Requiring operators to conduct baseline monitoring of wells or water resources near gas operations is an important objective for all stakeholders because it results in science-based measurement data that can be used to identify whether or not well activities cause contamination. For example, in Pennsylvania, operators who conduct pre- and post-baseline water monitoring of nearby water sources can overcome a rebuttable presumption that a well operator is responsible for pollution of nearby water resources if the monitoring demonstrates that constituents found in the sampled water sources did not come from the well operator's activities.[94] In Colorado, the Colorado Oil and Gas Association instituted a voluntary baseline monitoring program, with results being submitted to the Colorado Oil and Gas Conservation Commission (COGCC), provided landowner consent.[95] Colorado requires baseline water testing in the North San Juan basin (as well as other parts of the state), in limited circumstances to protect sources of drinking water, resources located near CBM wells, and in the Greater Wattenberg Area.[96] New York has proposed to require operators to make reasonable attempts to sample and test all residential water wells within 1,000 feet of a well pad prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the U.S. Department of Environmental Conservation.[97] For more information related to state baseline monitoring requirements, see Table 26, Appendix C, Baseline Monitoring Requirements.

2.3.5 Storage and Management of Wastes

2.3.5.1 Waste Storage

As noted above, waste storage is largely a matter of state and local law. The onsite storage of waste—such as produced and flowback water, drill cuttings, and fluids—is usually restricted to either storage tanks or open lined or unlined pits. Open pits pose a number of risks, including

[93] We do not include where state regulations refer to logs generally, as opposed to using the specific terminology "cement bond logs."
[94] 58 Pa. Cons. Stat. § 3218. In those instances where an operator is deemed responsible for contaminating or diminishing a private or public water source, he or she must restore or replace the water with an alternate source.
[95] Colorado Oil & Gas Association, "Colorado Oil & Gas Association Voluntary Baseline Groundwater Quality Sampling Program," http://www.coga.org/index.php/BaselineWaterSampling.
[96] Colorado requires baseline sampling of surface waters located downstream of drilling operations conducted near surface waters intended for drinking water and baseline sampling of water wells located near CBM wells. COGCC R. 317.b (2012). The state also recently added a statewide requirement that operators provide notice to surface and adjacent landowners, which must include instructions for the collection baseline water samples. COGCC R. 305.e.1.A (2012). Operators drilling in the Greater Wattenberg Area must also conduct limited baseline water sampling prior to drilling. COGCC R. 318A.
[97] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).

threats of drowning to migratory birds and wildlife, air pollution caused by the volatilization of hazardous or organic compounds, and soil and water contamination posed by overflowing pits or liner failures (Earthworks 2012, NM OCD 2008). According to the Ground Water Protection Council, "The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination" (GWPC 2009). This study did not perform a comprehensive analysis of state pit requirements; however, a preliminary review revealed significant variation among state pit rules in terms of liner, monitoring, fencing, and other construction and operation requirements, which is complicated somewhat by the use of inconsistent nomenclature for pit types.

An alternative to the use of pits is the use of closed-loop or "pitless" drilling systems that require the storage of fluids in tanks, preferably closed tanks, rather than open pits. Closed-loop drilling reduces many of the risks associated with open pits (Earthworks 2012). Closed-loop drilling also "allows for enhanced monitoring of fluid levels and characteristics which allows for more efficient use of drilling fluids, reduces waste, encourages recycling, and reduces potential liability associated with waste management and reduces site closure costs"[98] (TRRC 2012). New York has proposed to require closed-loop drilling for drilling fluids and cuttings associated with high-volume hydraulic fracturing operations. Colorado, Pennsylvania, Wyoming, and Fort Worth (Texas), require the practice in certain situations, such as where drilling occurs in sensitive areas where there is a heightened risk of water contamination from pit failure or the implications of contamination are more severe if contamination does occur. A recent bill introduced in Colorado would have required enhanced use of this practice statewide.[99] BLM's proposed rule for development on public and tribal lands provides for the use of either closed-loop systems or pits (BLM 2012). For a comparison of state and local closed-loop drilling requirements, see Table 27, Appendix C, Closed-Loop or Pitless Drilling Requirements.

2.3.5.2 Produced Water Disposal

State requirements regarding the disposal of produced water also vary considerably. Some of this variation can be explained by local conditions, such as the scarcity of underground injection wells in Pennsylvania, as noted above. However, disparate regulatory requirements also contribute to state-by-state variation.

In general, natural gas operators have a variety of options for disposing of wastewater. These include discharging wastewater directly to surface waters, sending the waste to treatment facilities such as POTWs or CWTs authorized to discharge, disposal via underground injection well, reuse for further hydraulic fracturing, disposal into evaporation ponds or impoundments, or disposal via land application. However, legal and practical constraints can limit some of these options.

Of the states reviewed, Colorado, Wyoming, and Texas allow for direct discharges only in specified circumstances (e.g., if produced water meets national effluent limitation guidelines for agricultural or wildlife propagation). State requirements vary considerably with respect to indirect discharges to POTWs or CWT facilities. All of the states studied except New York allow for disposal or storage of produced water in evaporation or open pits, subject to specific

[98] NY SGEIS, § 7.1.7.4.
[99] SB 12-107 (introduced January 31, 2012).

circumstances where closed-loop systems are required. Similarly, all states except New York and Texas allow for produced water to be disposed of via land application, such as road-spreading or land farming, but the specific requirements and limits for doing so vary considerably. New York has proposed to require operators to demonstrate that all flowback water and production brine will be treated, recycled, or otherwise properly disposed of over the projected life of the well,[100] and also, that operators prepare a waste tracking form for flowback and production brine similar to what is required for medical waste.[101] Operators in Pennsylvania must prepare a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flowback or production fluids, and most states are increasingly encouraging reuse and recycling. Additional requirements to incent or require recycling and reuse of produced and flowback are likely given the heightened interest in reducing the risk of contamination posed by other disposal methods, and reducing impacts to freshwater resources associated with withdrawals. See Table 28, Appendix C, Produced Water Disposal, for specific state disposal requirements for produced water.

2.3.6 Air Quality

As discussed above, EPA and the states exercise joint authority over standards to limit or report amounts of air pollution from unconventional gas activities.

State regulation of air contaminants varies significantly, with Colorado and Wyoming containing some of the most comprehensive and rigorous requirements to reduce emissions statewide and in areas home to significant drilling activity. Some of Colorado's and Wyoming's air rules have been driven by exceedances of the national ambient air-quality standards for ozone. For example, Wyoming adopted more stringent requirements to reduce VOCs from natural gas operations in the Upper Green River basin in response to elevated levels of ozone in the winter, as did Colorado in response to violations of national ambient air-quality standards for ozone in parts of the Denver-Julesburg Basin in the Denver Metropolitan Area. Attainment of national ambient air-quality standards (i.e., National Ambient Air Quality Standards) is determined at regional and local levels (so-called "air quality management regions"); also, states have flexibility under the Clean Air Act in developing state implementation plans under the National Ambient Air Quality Standards program. Therefore, state air pollution requirements and controls vary considerably.

In addition to meeting baseline federal requirements, areas that fail to meet—or are at risk of failing to meet—national ambient air-quality standards may adopt additional measures beyond those that apply statewide in order to improve air quality. Indeed, many of the standards recently adopted by EPA in its recent NSPS—such as those that apply to completions and re-completions of hydraulically fractured wells, storage vessels, and pneumatic devices—are similar to those already required in the Upper Green River basin in Wyoming and in Colorado (WY DEQ 2010, CDPHE 2012, COGCC 2008).[102] A different situation exists for the Barnett Shale, also in an area that fails to meet national ambient air-quality standards for ozone, where the state imposes few limits on the emissions of VOCs and hazardous air pollutants; here, EPA's new rules will add a number of requirements. See Table 29, Appendix C, for a comparison of how EPA's new

[100] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 750-3.12.
[101] NY SGEIS, § 7.1.7.1.
[102] See also COGCC R. 805.

reduced-emission completion requirement (or "green completion") compares with existing requirements in the basins reviewed.[103]

Despite EPA's enhanced role in regulating air pollution, states retain substantial discretion to regulate uncovered sources or pollutants, or, where permitted under state law, adopt more stringent rules and/or require additional reporting. For example, Pennsylvania recently added a requirement that natural gas operators report annually amounts of air pollutants.[104] New York has also proposed additional clean-air measures, including a requirement that natural gas operators submit plans to reduce GHG emissions.[105] State requirements vary considerably related to the amount of associated natural gas that operators may flare or vent during production. As production increasingly shifts toward liquids and oil-rich formations, this issue is likely to be an area of continuing policy focus because EPA's reduced-emission completion requirement does not apply to associated gas emitted during the production phase of oil wells.[106] EPA's recent Fort Berthold Indian Reservation rule provides one example of how regulators, going forward, may address the problem of associated gas emissions.

A number of recent air studies and reports have raised questions related to the sufficiency of current air regulations to protect the health of local communities from hazardous air pollutants and reduce fugitive and vented methane emissions (McKenzie et al. 2012; Petron 2012). As the industry expands, especially into more densely populated areas, concerns regarding air quality and GHG emissions will likely persist and receive ongoing regulatory attention.

2.3.7 Compliance Monitoring and Enforcement

Compliance is essential if regulations are to serve their purpose of mitigating environmental risks. Significant challenges for compliance monitoring occur due to the unique nature of the unconventional natural gas industry, characterized by dispersed and often remotely located facilities controlled by numerous operators whose practices can vary significantly. On top of this, regulators face a rapidly changing industry as development, technologies, and practices continue to expand in scale and scope.

A number of reports that have addressed the adequacy of state compliance monitoring and enforcement capabilities conclude that state inspection and enforcement capacity varies significantly, as do state processes for recording and disseminating compliance histories to the public (Groat and Grimshaw 2012; Earthworks 2012b; Soraghan 2011). For example, as Table 5 illustrates, Colorado and Wyoming have 15 and 12 inspectors, respectively, dedicated to oil and gas facilities (Earthworks 2012b; Groat and Grimshaw 2012). Pennsylvania, by comparison, quadrupled its enforcement staff in 2010, resulting in 193 enforcement personnel, 65 of whom are inspectors (Earthworks 2012b). Similarly, Texas has 125 inspectors while Louisiana has 38 (Groat and Grimshaw 2012, LDNR 2011). Data for New York were not identified.

[103] Texas air rules are not comparable to EPA's recent rules in overall scope or rigor, with the exception of Fort Worth's "green completion" requirement. See Appendix C for green completion requirements.
[104] Act 13.
[105] NY SGEIS, § 7.6.8.
[106] For a discussion of this issue, see Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (September 28, 2011).

As illustrated in Table 5, the number of inspections performed in each state varied considerably as well, although the data demonstrate a correlation between the number of inspectors and number of onsite inspections. Adequate inspection capability is critical to carry out the SEAB recommendation that "regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing" (SEAB 2011a).

Table 5. Compliance Monitoring and Enforcement Capabilities[107]

State	Inspectors (2010–2011)	Field Inspections (2010–2011)	Total Violations (2009–2011)	Percent of total Violations that are Procedural	Percent of Violations that Result in Enforcement[108]
CO	15[109]	16,228[110]	N/A	N/A	N/A
LA	38[111]	363	158	60	70
PA	65[112]	298	2,280	22.4	N/A
TX	125	N/A	35[113]	72[114]	20
WY	12	2	N/A	N/A	N/A

Research conducted by the University of Texas identified significant variation among states in terms of the types of violations found (e.g., pit and tank construction and maintenance are the most common violations in Louisiana, whereas permitting violations are most common in Texas). Despite the variation in violations, it appears that most violations identified are minor or procedural violations. Note, however, that this does not necessarily mean that most environmental impacts associated with gas development are minor, nor that companies comply with more "serious" requirements at higher rates. A number of factors affect the types of violations that inspectors identify, such as the visibility of violations (e.g., special equipment is needed to detect and measure natural gas leaks from equipment), state inspector capacity to respond to complaints or conduct investigations, and types of complaints reported (Groat and Grimshaw 2012).

Enforcement varies considerably among states, as well. Table 5 illustrates that the percent of violations leading to enforcement actions differed significantly among states where data are available (e.g., 70% of violations noted resulted in enforcement actions in Louisiana compared to only 20% in Texas) (Groat and Grimshaw 2012; Soraghan 2011). Penalties also vary significantly across jurisdictions, due in part to statutory constraints limiting the amount of penalties a state may assess for a given violation (e.g., the maximum fine for a violation in Colorado is $1,000 per day, whereas enforcement authorities in Pennsylvania and Texas can issue fines of $5,000 and $10,000 per day, respectively) (Earthworks 2012b). Some have questioned whether monetary penalties are sufficient to deter non-compliance given the

[107] Data taken from Groat and Grimshaw (2012), unless otherwise noted.
[108] Soraghan 2011.
[109] Earthworks 2012b.
[110] *Id*.
[111] LDNR 2011.
[112] Earthworks, 2012b.
[113] See Chapter 4.
[114] These are for 2008–2011, rather than 2009–2011.

resources of some companies (Earthworks 2012; Soraghan 2011). Others posit that orders to cease production may be more likely to lead to compliance (Soraghan 2011).

Lastly, public dissemination regarding violations, enforcement actions, and company compliance histories also varies across states. Of the states reviewed, only Pennsylvania maintains a publicly searchable database of violations and enforcement actions. More complete and publicly available data on the compliance histories of companies are needed to understand the effectiveness of compliance and rules, as is more transparency and consistency in the ways that states record and report violations and impose penalties (SEAB 2011a). As with regulations themselves, unevenness in state compliance monitoring and enforcement capacity can lead to additional uncertainty and gaps as well as delay, because public mistrust of industry and regulators can undermine the industry's social license to operate, resulting in bans or moratoria on drilling.

2.3.8 Summary of State Statutory and Regulatory Framework

States are the primary regulators, inspectors, and enforcers of most impacts associated with unconventional natural gas development. Regulatory requirements, compliance monitoring, and enforcement capabilities vary across states. Some of this variation is reduced by the recent trend toward consistency in requirements related to the public disclosure of fluids and the amount and sources of water used in hydraulic fracturing. Additional regulation is likely in the area of well integrity standards—specifically, greater adoption of requirements to ensure adequate casing and cement jobs such as cement bond logs and pressure testing of casing. In addition, in light of continued public concern regarding adverse air, water, and waste impacts associated with unconventional gas development, states are likely to adopt regulations requiring baseline water-monitoring requirements, air-quality rules, and provisions that encourage or require greater reuse of produced and flowback waters. Some states may need to increase their inspection and enforcement resources to ensure that rules are being followed. Processes that provide greater transparency regarding state methods for identifying violations and bringing enforcement actions would help to improve public understanding of the extent to which additional resources are needed. Additional accountability and public trust are likely to result from self-reporting mechanisms that are publicly available, such as a joint industry non-governmental organization database on company compliance records (see SEAB 2011a).

2.4 Local Regulation and Social License to Operate

Across the country, communities have responded to the increased development of unconventional natural gas with mixed reactions. In half of the states reviewed for this study (Colorado, New York, and Pennsylvania), legislation has recently been proposed or enacted to limit the power of local governments to regulate unconventional gas development, or to make such local authority explicit (see Figure 12). In these states, 30 local governments have banned hydraulic fracturing or oil and gas development altogether, and an additional 73 have issued temporary moratoria pending review and potential revision of local land-use or other ordinances.[115] This section examines three different approaches to the issue of local authority,

[115] A handful of states have also banned or issued moratoria. In addition to New York, New Jersey (see A 3653 (introduced Jan. 6, 2011, http://www.njleg.state.nj.us/2010/Bills/A4000/3653_R1.HTM), and Maryland (see The Marcellus Shale Safe Drilling Act of 2011 H.B. 852 (effective June 1, 2011, http://mlis.state.md.us/2011rs/fnotes/bil_0002/hb0852.pdf) instituted temporary moratoriums on hydraulic fracturing; Vermont recently banned the practice (see H. 464 [enacted May 16, 2012]).

and provides an example of one set of requirements—setback requirements—intended to protect local communities and sensitive resources from adverse drilling impacts to illustrate differing approaches across and among states.

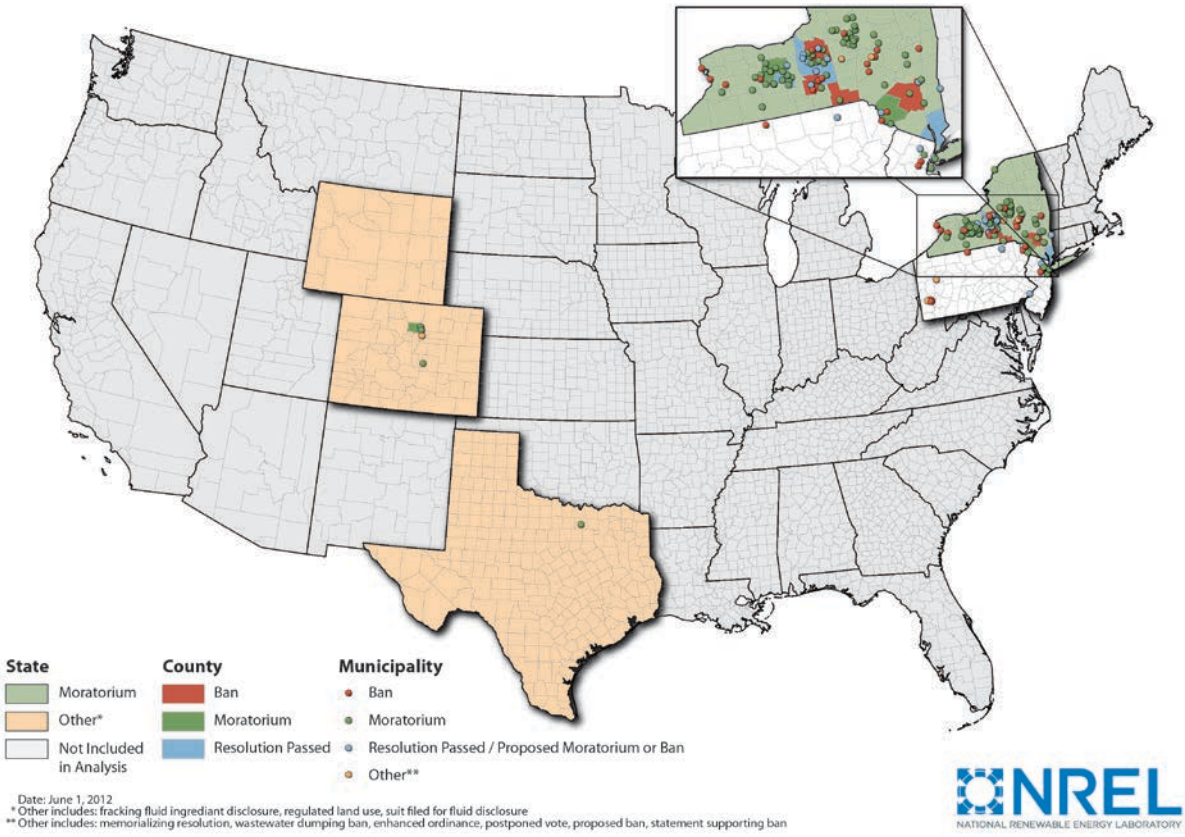

Figure 12. Variation in the rules for six states of rules covering natural gas fracking

States grappling with the issue of local control have adopted very different postures. At one end of the spectrum, Pennsylvania recently enacted legislation that places virtually all control over natural gas development in the hands of the state government.[116] This law, which went into effect April 16, 2012, elicited significant public opposition (Robinson 2012a; Robinson 2012b). A state court judge recently overturned those portions of the law restricting local governments from regulating oil and gas development on the basis that they unconstitutionally violate the substantive due process rights of local governments to enact zoning ordinances that protect the interests of neighboring property owners and neighborhood characteristics (Pellegrini 2012).

[116] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to the Pennsylvania municipalities and planning code and Flood Plain Management Act and provides that "all local ordinances regulating oil and gas operations shall allow for the reasonable development of oil and gas resources." Municipalities must allow "oil and gas operations, other than activities at impoundment areas, compressor stations and processing plants as a permitted use in all zoning districts." The Act allows for the location of well pads within 300 feet of existing buildings, unless the wellhead is less than 500 feet from any existing building. Under the Act, counties may require oil and gas operators to pay impact fees ranging from $40,000 to $60,000 for the first year of production adjusted based on natural gas prices and inflation thereafter. 58 Pa. Cons. Stat. § 3218.

The Corbett Administration filed an appeal of that decision which is set to be heard by the Supreme Court of Pennsylvania on October 17, 2012.[117]

New York's approach to local control represents the other end of the spectrum. In that state, 26 localities have banned natural gas development or hydraulic fracturing altogether, two of which have been upheld as valid exercises of local zoning authority (Dryden 2012; Middlefield 2012). In addition, two bills have been proposed in New York that would allow local governments to enact or enforce laws and ordinances relating to oil, gas, and solution mining.[118]

In Colorado, the issue of local control over oil and gas drilling has become an increasingly prominent subject of discussion. Earlier this year, the Governor formed a multi-stakeholder task force to address the issue. The task force ultimately recommended "coordinated regulation through a collaborative approach…" (CDNR 2012), but what this means in practice remains to be seen. Five bills related to the topic of local control were introduced in the most recent legislative session.[119] In addition, four localities in the Front Range have moved to delay drilling pending a review of their oil and gas, land use, and public health laws; a fifth locality is currently considering a moratorium.[120] To date, the result of these reviews has been one set of final regulations issued by the City of Longmont, draft regulations issued by Boulder County,[121] and one set of operator agreements.[122] The City of Longmont finalized its ordinance in July 2012. The ordinance includes riparian and residential setbacks, disclosure requirements, water testing, wildlife protections, and a ban on drilling in residential areas.[123] Boulder County's draft revisions also contain residential and riparian setbacks, water-testing requirements, emergency response, and other measures intended to protect public health such as air-pollution controls.[124] Shortly after Longmont issued its ordinance, the Colorado Oil and Gas Conservation Commission filed a lawsuit against the City of Longmont alleging that state law preempts a

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[117] Scott Detrow, *StateImpact*, "Corbett Administration Filed Act 13 Appeal with State Supreme Court" (July 27, 2012), http://stateimpact.npr.org/pennsylvania/2012/07/27/corbett-administration-files-act-13-appeal-with-state-supreme-court/.

[118] A8557 (Aug. 24, 2011) (authorizes local governments to address natural gas drilling in their zoning or planning ordinances); A3245 (Jan. 24, 2011) (would allow local governments to enact and enforce local laws/ordinances of general applicability).

[119] SB 088, introduced Feb. 16, 2012 (would have granted COGCC exclusive jurisdiction to regulate oil and gas operations); HB 1173, introduced Feb. 6, 2012 (would have required closed-loop systems for hydraulic fracturing fluid storage/containment); HB 1176, introduced Feb. 6, 2012 (would have mandated setbacks of at least 1000 feet from any school or residence in urban areas); HB 1277, introduced Feb. 20, 2012 (would have stated that oil and gas operators would be subject to the same local government control as for other types of mineral extraction, i.e., a shared state and local approach); SB 107, introduced May 5, 2012 (contained specific requirements, such as closed-loop drilling, water reporting requirements, and the prohibition of the use of carcinogens in hydraulic fracturing fluids).

[120] As noted above, these include Boulder County, Erie, Longmont, and Colorado Springs. At the time this chapter went to publication, the town of Lafayette, Colorado, was considering a temporary ban on oil and natural gas drilling. *NGI's Shale Daily*, "Another Colorado City Considering Drilling Restrictions" (September 6, 2012).

[121] At the time this Chapter went to publication, the Boulder County Planning Commission was considering proposed Land Use Code amendments to address drilling in the County. The City of Longmont finalized its oil and gas revisions to its Municipal Code, Ordinance O-2012-25, on July 17, 2012.

[122] Copies of the agreements are available on the Town of Erie's website, http://www.erieco.gov/CivicAlerts.aspx?AID=487 (last visited September 25, 2012).

[123] City of Longmont Ordinance O-2012-25 (July 17, 2012).

[124] Boulder County, Docket DC-12-0003: Amendments to Oil and Gas Development Regulations, http://www.bouldercounty.org/find/library/build/dc120003stafrecregs20120924.pdf.

number of the purported protections including the riparian and wildlife setbacks, residential well-site ban, disclosure rule, water-testing requirements, a requirement that operators use multi-well sites, and visual mitigation measures.[125] The Oil and Gas Conservation Commission has yet to take an official position on Boulder County's regulations. Nevertheless, the Commission's suit against Longmont may indicate that the approach recommended by the Governor's Task force earlier this year will tilt in favor of state rather than local regulation, with the amount of control retained by the local governments unclear.

Local governments across all states covered in this study are also seeking to impose additional setback requirements, but the governing state law on these requirements varies by jurisdiction. Local setback requirements that are more stringent than state law exist in the Barnett Shale play, Eagle Ford play, Marcellus Shale play in Pennsylvania, and North San Juan basin. There is considerable variety in setback requirements, as well as increasing public interest in this issue. Lack of consensus regarding the appropriate distance required to protect against adverse air, noise, visual, or water pollution may, in part, explain the continuing controversy over setback requirements (CU 2012). For a comparison of specific state and local requirements, see Table 30, Appendix C, Setback Requirements.

2.5 Best Management Practices

Various commissions and reports have stressed the need for continuous improvement in industry practices, as well as industry-led organizations dedicated to developing and disseminating information on best practices (SEAB 2011b; NPC 2011; IEA 2012). Technological innovation in the effort to control and mitigate some of the resource and environmental impacts of unconventional gas development can improve efficiency, reduce environmental risk, and bolster public confidence. As in many industries, leading operators in unconventional gas development have often performed at a level over and above existing regulatory requirements, providing important sources of innovation for new practices and regulations. Notably, a handful of important regulatory developments started as best management practices adopted by leading operators.

For example, as noted above, prior to EPA's adoption of its recent NSPS for the oil and gas sector, leading companies implemented reduced-emission completions ("green completions") to increase profits by maximizing sales of natural gas from the recovery of natural gas otherwise lost to the atmosphere; others voluntarily report chemicals used in hydraulic fracturing fluids to the Groundwater Protection Council's public FracFocus website.[126] Today, a number of companies are developing methods to recycle and reuse flowback and produced waters that reduce operator costs, as well as the risks associated with other forms of disposal.[127] As discussed in the following chapter, documenting such beyond-compliance best practices is an area that merits further study.

[125] Colorado Oil and Gas Conservation Commission v. City of Longmont (filed August 30, 2012 in the Boulder County District Court).
[126] See Ground Water Protection Council Chemical Disclosure Registry, http://fracfocus.org/.
[127] See GIS Mapping Tool in Chapter 4 of this report.

2.6 Conclusion and Key Findings

The combination of hydraulic fracturing and horizontal drilling has been hailed by some as the most important energy innovation of the last century, with dramatic implications for the economics and politics of energy in the United States and throughout the world. This "disruptive" technology has fueled a boom in unconventional gas development in various parts of the United States over the last 10 years. Law and regulation (at multiple levels) have struggled to keep up with the rapid growth of the industry. And the contemporary legal and regulatory landscape that applies to unconventional natural gas development is complex, dynamic, and multi-layered.

The federal government has demonstrated a keen and growing interest in this area, as evident by the prominent role natural gas plays in the current Administration's energy policy (White House 2011), the formation of the SEAB Subcommittee, and the announcement or promulgation of a number of new rules related to air and water quality, data collection regarding the aggregate amounts of chemicals used in fracturing fluids, and development on public lands discussed above. Additional federal regulations and new legislation are also possible. The results of EPA's study on the effects of hydraulic fracturing on drinking water could play a key part in directing any such changes.

States will continue to serve as the major source of regulation, with primary responsibility for well-construction standards, disclosure requirements for hydraulic fracturing fluid chemicals and water used during well stimulation, baseline water-monitoring requirements, waste management, and overall compliance monitoring and enforcement. State and local requirements—other than disclosure requirements regarding chemicals and water usage—vary considerably, and this is likely to continue as more states revise their rules to respond to new development. Greater coordination between regulators at all levels of government could help to reduce uncertainty and fragmentation,[128] as would greater reliance on the expertise contained in organizations such as the State Review of Oil and Natural Gas Environmental Regulation and the Ground Water Protection Council (SEAB 2011a; SEAB 2011b).

State compliance monitoring and enforcement capabilities vary widely. The limited data that have been assembled indicate most violations are minor, but that "enforcement actions are sparse compared to violations noted" (Groat and Grimshaw 2012). Substantially more data and research are needed to understand the extent to which companies are complying with state, local, and federal requirements.

This information gap could begin to be filled by greater reporting, via self-certification requirements that are publicly available, as well as by state databases, searchable by the public, that contain compliance and enforcement records. These activities would also bring greater certainty to this issue.

A number of commissions and industry associations have expressed support for continued development and implementation of beyond-compliance measures (SEAB 2011b; NPC 2011; IEA 2012), and the need for such measures to avoid controversy, delay, and continued

[128] For example, BLM's recent proposed rule notes the importance of consistency in federal and state disclosure requirements and the intent to provide consistency by lining up its requirements with those adopted in leading states.

opposition in certain parts of the country. As discussed in the following chapter, more work is needed to identify and evaluate such measures. Given the rapid pace of unconventional gas development in various parts of the country, best practices will have to complement regulation—and, in some cases, be folded into it. But as the regulatory landscape evolves, it will be important to establish a framework, where possible, that incentivizes the ongoing development and adoption of new state-of-the-art practices and technologies to minimize the risks associated with developing natural gas resources.

3 Key Issues, Challenges, and Best Management Practices Related to Water Availability and Management

3.1 Introduction and Objectives

Shale gas development has several categories of potential risks including air, water, land, and community (Figure 13). Examples of air risks include emissions of GHGs (largely methane) and hazardous air pollutants (e.g., benzene). Land impact risks include ecosystem degradation and land disturbance. Related to water, the risks are either quantity related (regional water depletion) or concerns of quality (surface or groundwater contamination). Community risks include excessive truck traffic and the noise, road damage, and other associated impacts. Induced seismicity is also considered a community issue and the broadest community risk from it could be the loss of the social license to operate (e.g., Energy Institute 2012; Robinson 2012; Zoback et al. 2010.)

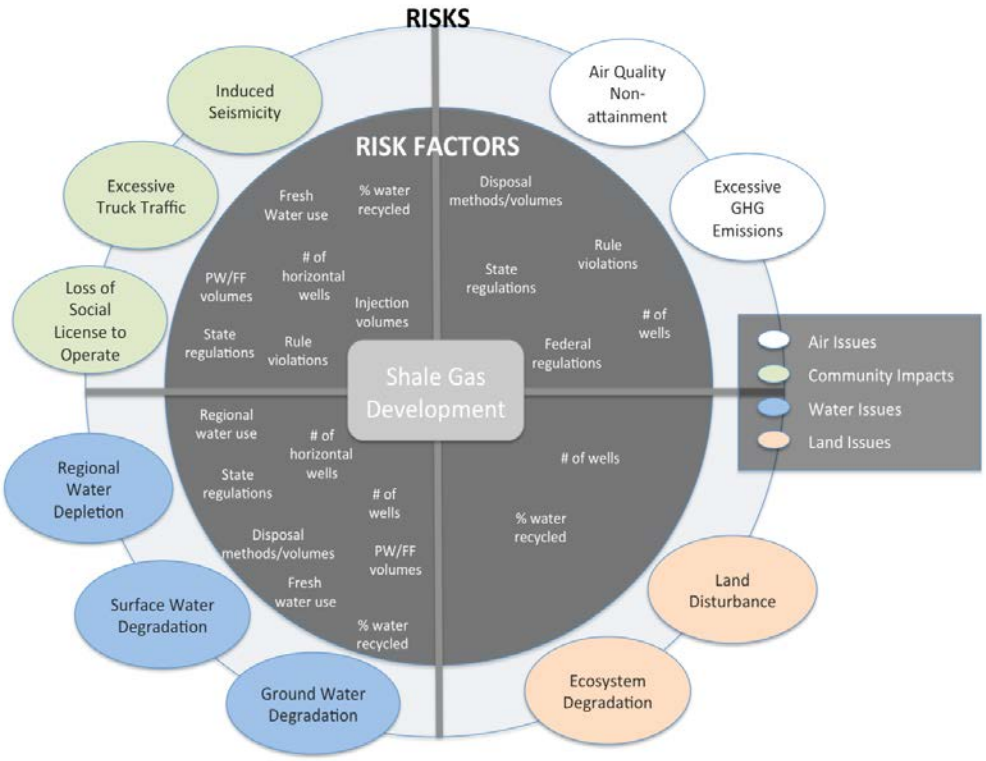

Figure 13. Description of shale gas development risks and characterization metrics

This chapter focuses on the risks and impacts of shale gas development on water resources. Ongoing improvement of the quality and quantity of water resource-related data will inform decisions related to shale gas development. Data collected in this chapter mark the beginning of the risk characterization needed to adequately define best management practices. Specifically, unconventional shale gas development might impact water resources through four major causal routes—one related to water quantity and three related to water quality.

- Water Quantity:
    - Regional water depletion due to large volumes of freshwater use for hydraulic fracturing
- Water Quality:
    - Surface and groundwater degradation resulting from inadequate construction practices and well integrity
    - Surface and groundwater degradation resulting from inadequate onsite management of chemicals used in hydraulic fracturing
    - Surface and groundwater degradation resulting from inadequate wastewater management practices

To better understand the risks to water resources from shale gas production, the variety of risk factors related to water need to be further defined and a thorough spatial and temporal characterization should be completed. The science regarding risks and impacts of the shale gas industry is relatively new and still in a state of flux (EDF 2012; IEA 2012). For this project, we approached the topic by using available literature studies, public databases, and industry interactions.

We established the following objectives to assess the risks to water resources:

- Understand the quantities of water currently being used in six shale plays in the United States as they relate to current estimates of water availability and existing water uses
- Understand the quantities of flowback and produced water for each shale play and the wastewater management techniques employed
- Identify Best Management Practices, including quantity and quality impacts and costs

To accomplish these objectives, we studied six unique natural gas producing regions of the country (as identified in Chapter 2) to capture the spatial variability of water use, water availability, and wastewater management (see Table 8). The six regions include a coalbed methane (CBM) basin (North San Juan); a vertically fractured tight sand basin (Upper Green River); three primarily dry gas shale formations (Barnett, Haynesville, and Marcellus); and one shale formation that is producing condensates and oil along with natural gas (Eagle Ford).

3.2 Importance of Water for Shale Gas Development

The recent expansion of shale gas development is, in part, due to advances in horizontal drilling and hydraulic fracturing. As shale gas development continues to grow rapidly across the U.S., the demand for water used during site operations is also expected to increase (COGCC 2012b). Drilling and fracking operations involved in shale gas development require millions of gallons of water per well that must be acquired and transported to sites to fracture the shale formations (EPA 2011). Hydraulic fracturing is essential for tight formations such as shale because the

geological structure does not have the necessary permeability to allow natural gas to flow freely through the formation and into a wellbore (Arthur 2011). The current development of unconventional shale gas would not be economically viable without hydraulic fracturing, making it important to have an adequate, dependable supply of water to support fracking operations. Equally important is preventing fracking operations from negatively affecting a region's water resources, both in terms of quantity and quality.

Water used in hydraulic fracturing comes from several sources including surface water, groundwater, municipal potable water supplies, or reused water from other water sources (Veil 2010). To date, freshwater has been used for most hydraulic fracturing operations in most regions (Nicot 2012). Surface water, such as streams, rivers, creeks, and lakes, are the largest source of fresh water for operators in the Eastern United States. Groundwater can be a feasible source of water, but only when sufficient amounts are available. In Texas, groundwater is more commonly used than surface water. Public water supply might be an alternative in some regions, because permits for surface and groundwater can take more time to secure.

The impact of water usage will depend on the availability of local water resources, which can vary regionally depending on the geographic location of the shale play, ground and/or surface water sources, and competing demands for water from other users. In locations vulnerable to droughts, operational water needs could adversely impact the viability of gas production from tight formations (Vail 2010). Droughts, particularly in water-stressed regions (such as the arid Southwest), can limit the amount of available water, increasing the competition for water between potable water supplies, water for agriculture, and water for fuel.

3.3 Assessment of Risks to Water Quantity and Water Quality

Shale gas development may incur risks to both regional water quantity and quality. Quantity-related risks depend on the number of wells drilled, water use per well, amount of recycling or non-potable water use that occurs to offset freshwater demands, and local water availability. Quality-related risks depend on onsite construction techniques, onsite chemical management practices, and wastewater management practices. Risks may vary for any given shale gas development site. In many cases, risks to water resources extend beyond the location of the well being drilled, depending on the source location of the water and where wastewater is treated. Figure 14 shows the various risks to water resources that can result from hydraulic fracturing operations.

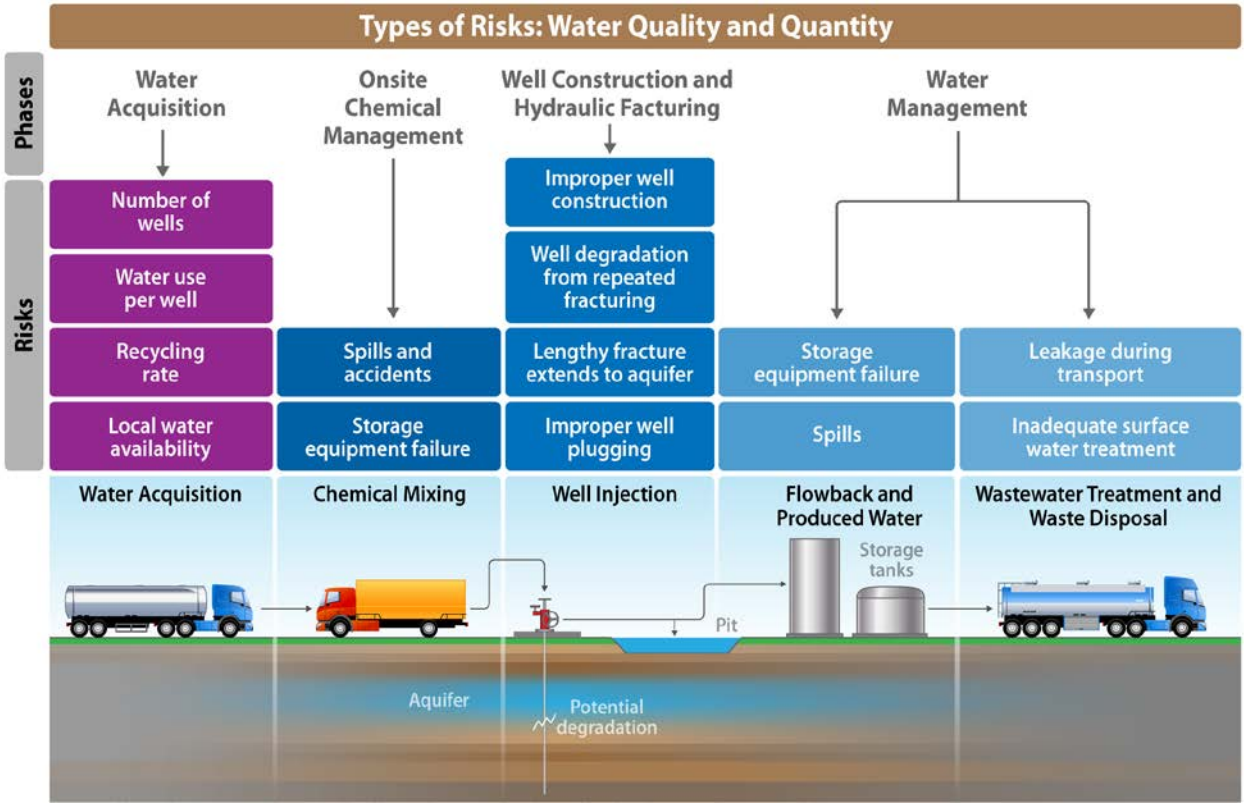

Figure 14. Water quality risks by phase of natural gas production.[129]

3.3.1 Risks to Water Quantity

3.3.1.1 Current Industry Activities Affecting Water Use

A crucial component of hydraulic fracturing is securing a sufficient amount of water for operations. Water may not always be available on the lease site; therefore, developers may have to obtain access to water from a different location and transport water to the site. In such cases, the risks to water resource quantities are assessed with respect to the water's source location, not to where it is eventually used. Where operators source their water depends on several factors, such as location, availability, timing, and cost. The closer a water source is to a well, the lower are the operational costs, whether it be pumping or transporting the water by truck.[130] In many cases, the total amount of water required for multiple operating wells (and the permits required) will be greater than local daily flows. For example, in Pennsylvania, the Susquehanna River Basin Committee (SRBC), which oversees all water source permits in the basin, has approved permits totaling 108 MGD (million gallons per day) at 151 locations (as of September 1, 2011), whereas the estimated peak daily withdrawal of those locations is only around 30 MGD. This means that freshwater impoundments might need to be constructed to collect and store water over a period of time to eventually be used to supply water for drilling and developing multiple wells (SRBC 2012).

[129] Graphic adapted from (EPA, 2011).
[130] Trucks can often have an impact on rural roads, both in terms of increased traffic and increased wear on roads. Analysis of these impacts is beyond the scope of this paper.

Total water use at a shale gas development site depends on the number of wells drilled, water use per well, and amount of recycling that occurs. The term water "use" is used in this chapter, which, in part, reflects the ambiguity of whether the water usage reported in publicly available sources represents freshwater withdrawals, use of freshwater along with recycled water, water consumption, or a combination of these categories. Future research could clarify the definitions of water usage reported by industry.

Number of wells

In the areas for which data are available, the number of producing wells drilled each year has been increasing since 2009 (Figure 15).

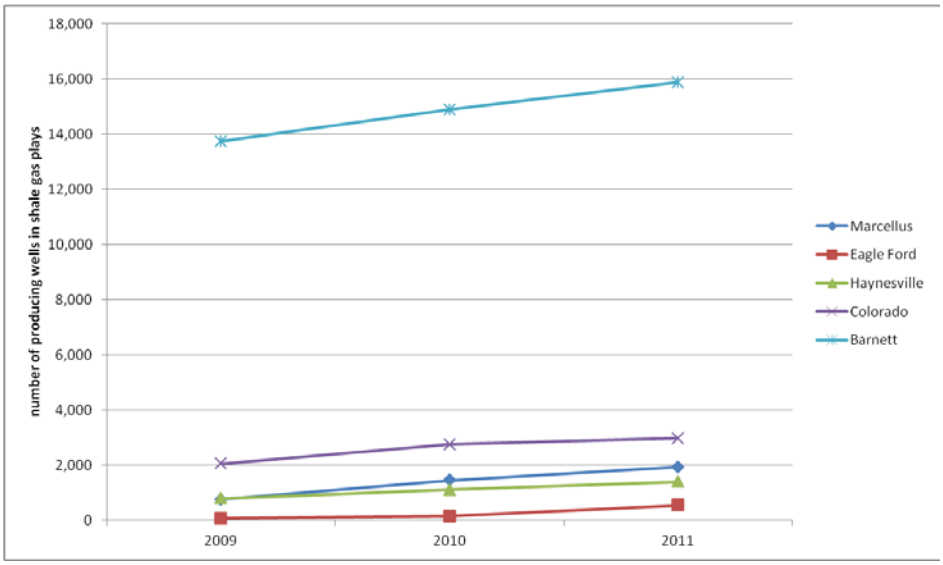

Figure 15. Total number of producing wells in shale gas plays, 2009–2011 (TRRC 2012c; COGCC 2012b; LADNR 2012; PA DEP 2012a; Eagle Ford Shale 2012).

The greatest number of wells is in the Barnett Shale formation, increasing 16% from 2009 to 2011, with nearly 16,000 producing wells (TRRC 2012c). In the other formations considered in this study, the total numbers of wells are smaller, but have been increasing faster. From 2009 to 2011, the total number of wells increased by 45% in Colorado (COGCC 2012b), 76% in the Haynesville formation (LADNR 2012), 154% in the Marcellus formation (PA DEP, 2012a), and 721% in the Eagle Ford formation (Eagle Ford Shale 2012). In all of these formations, well drilling applications have continued to increase each year, indicating a continued trend for the near future.

Water use per well

Data on the water usage per well were available for five of the six regions considered here. Data from about 100 nominal wells were randomly collected for four regions (Marcellus, Barnett, Eagle Ford, and Haynesville) from www.fracfocus.org, a voluntary online chemical disclosure registry of the water used for fracturing. FracFocus provides statewide and county-wide data. Well data are classified according to their API number, county, fracture date, operator name, well name, well type (Oil/Gas), latitude, longitude, datum, and total water use (including fresh water, produced water, and/or recycled water). Water use statistics are compiled and are displayed in Appendix D.

Average water use from the 100-well study in the five regions ranges from 1.1 to 4.8 million gallons per well, with a multi-region average of 3.3 million gallons per well (Figure 16).

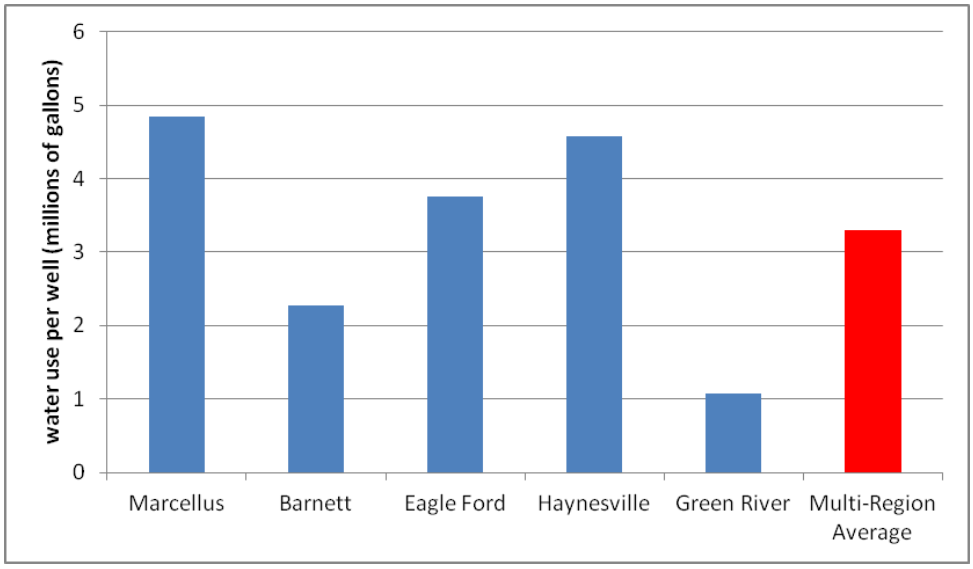

Figure 16. Average water use per well (in millions of gallons) for five regions (2011) (Fracfocus.org).

The Barnett, Eagle Ford, and Green River formations had average water uses of less than 4 million gallons per well, and the Marcellus formation had the highest average water use of 4.8 million gallons per well. Furthermore, considerable variation in water use per well within each formation is shown in Figure 17.

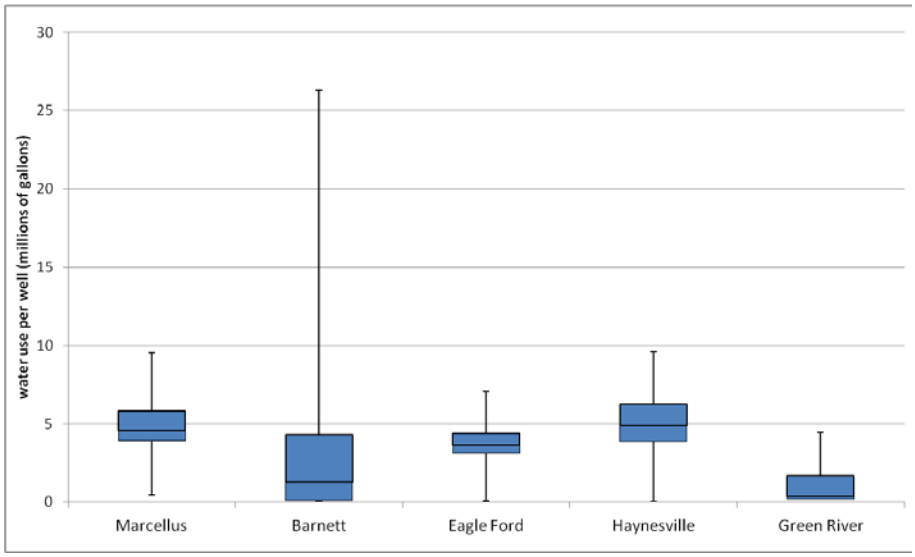

Figure 17. Water use per well for four formations, in millions of gallons. (fracfocus.org)

Note: Low and high error bars represent minimum and maximum reported water usage per wells, respectively. Upper and lower ends of boxes represent 75th and 25th percentile, respectively. Horizontal lines in boxes represent medians.

Results of the 100 well analyses indicate that water usage per well can vary by up to three orders of magnitude (29,000 gallons to 26 million gallons per well in the Barnett formation) depending on geology, type of well and drilling techniques, and industry practices. Median estimates of water usage per well are around five million gallons for the Marcellus, Eagle Ford, and Haynesville formations, yet individual wells can vary greatly. The Barnett formation has the second lowest median value of 2.3 million gallons per well, yet also the highest individual well value of 26 million gallons per well. These statistics do not indicate whether a portion of the water utilized for hydraulic fracturing includes recycled water.

Recycling rates

The impacts on local freshwater resources can be reduced by recycling produced water and frac flowback water. To use wastewater, a series of steps are commonly employed (Mantell, 2011). The water must often be stored in onsite holding tanks before treatment and is filtered or transported to another storage tank to test its remaining constituents. The water is then pumped or otherwise transported to another well location for reuse. Currently, only Pennsylvania tracks the amount of produced water and frac flowback water being recycled for reuse for drilling and hydraulic fracturing operations. Other states considered in this analysis do not have recycling or reuse as a category in their annual reporting forms, yet recycling may be occurring. In Pennsylvania, recycling of produced water has increased from 9% in 2008 to 37% in 2011 (PA DEP 2012b). In general, recycling of frac flowback water has increased from 2% in 2008 to 55% in 2011. In 2011, based on data reported, this recycling led to the reuse of about 65,000 gallons of produced water per well and 120,000 gallons of frac flowback water per well (Figure 18).

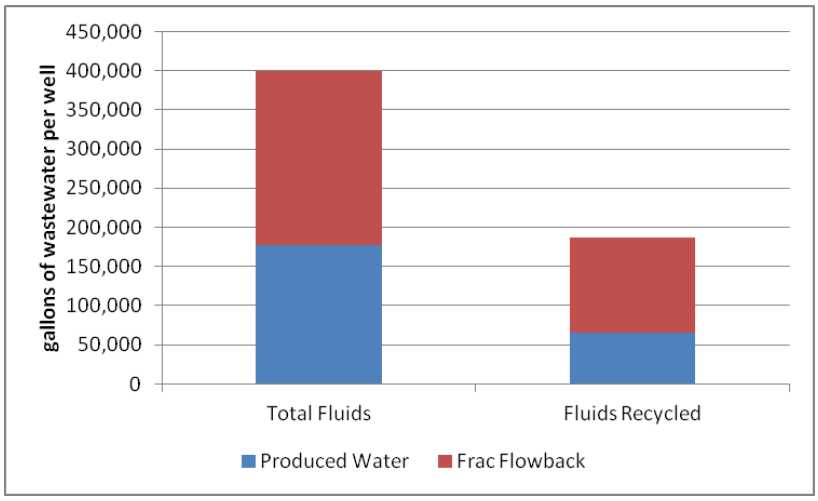

Figure 18. Wastewater production and total recycling at shale gas operations in Pennsylvania in 2011 (PA DEP 2012b)

Although data are not available for recycling rates in other formations, certain state organizations actively encourage recycling practices. The Railroad Commission (RRC) of Texas has provided authorization for seven recycling projects in the Barnett formation, five of which are still active (TRRC 2012d). No recycling authorizations have been given for the Eagle Ford or Haynesville formations to date. The Colorado Oil and Gas Conservation Commission (COGCC) actively

encourages reuse and recycling of water used in well construction as well as produced water. Although there are no data of quantities, the COGCC notes that several operators in the Piceance Basin have constructed infrastructure for reusing water for drilling and completing new wells (COGCC, 2012b).

The feasibility of recycling and reusing produced water and frac flowback depends, in part, on how much and how quickly water returns to the surface. In the Marcellus and Barnett shale formations, Chesapeake Energy reports that about 500,000 to 600,000 gallons per well will return to the surface in the first 10 days, compared to about 250,000 gallons per well in the Haynesville formation (Mantell, 2011). How much of the produced water can be recycled depends on the chemical composition of the water, including its total dissolved solids (TDS), total suspended solids (TSS), and its concentration of chlorides, calcium, and magnesium. High TDS can increase unwanted friction in the fracking process. High TSS can plug wells and decrease the effectiveness of biocides. High concentrations of other elements can lead to high risks associated with scaling.

Recycling produced water and frac flowback can partially reduce the demand for freshwater sources for new hydraulic fracturing operations. The reduction in freshwater demand is limited by the amount of water that is returned to the surface. In general, the amount of water returned to the surface—and thus, the amount of water that could be recycled—is on the order of 10% of the freshwater requirements for developing a well with hydraulic fracturing. The volumes of produced water may vary widely from well to well, making it difficult to predict how much water is produced and how much recycling potential there is for each well.

Water availability

Local water availability conditions in the six study regions can vary greatly. Further information of each shale region can be found in Appendix D. An overview of the six regions is shown in Figure 19.

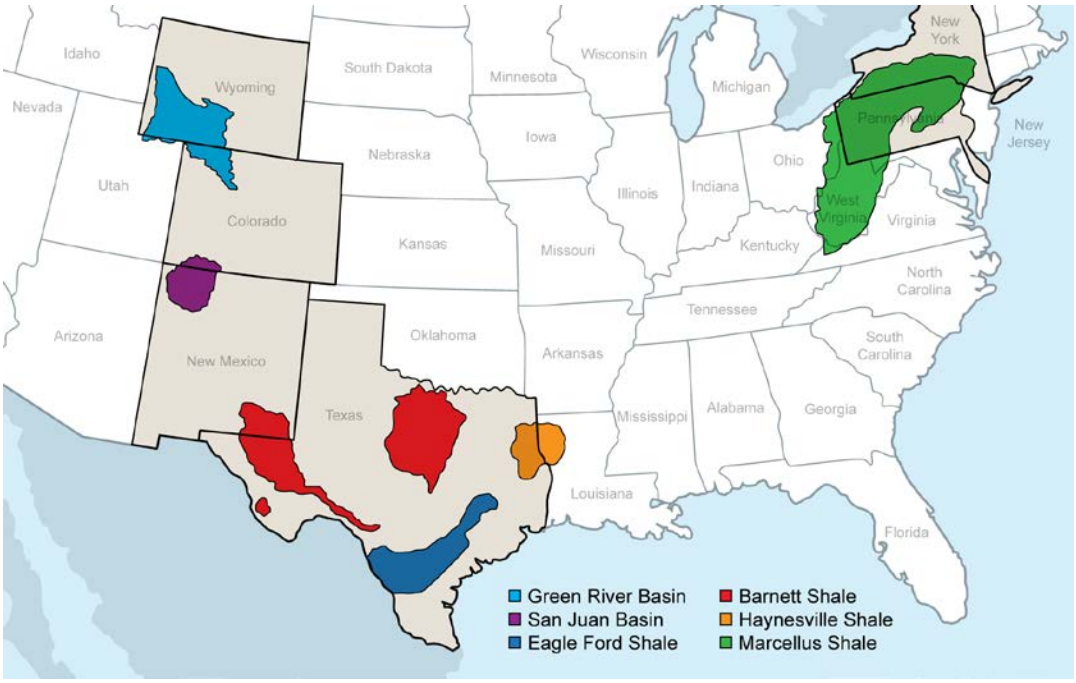

Figure 19. Six shale plays considered in this study.

Marcellus Shale, PA

The Marcellus Shale is located within or nearby highly populated areas of the northeast U.S. occupying the states of New York, Pennsylvania, Maryland, West Virginia, and Ohio. Competition for water might be challenging for shale gas development. However, the area overlying the Marcellus Shale formation has abundant precipitation, making water readily available (Arthur 2010). Three major watershed basins overlie the formation: the Susquehanna, Delaware, and Ohio River Basins are the main suppliers of water for shale gas development. The Marcellus Shale is overlain by about 72% of the Susquehanna River Basin (SRB), 36% of the Delaware River Basin, and about 10% of the Ohio River Basin (Arthur 2010). The SRB drains 27,510 square miles, covering about half the land area of Pennsylvania and portions of Maryland and New York (Arthur 2010). Major streams and rivers in the SRB are potential surface water withdrawals for shale gas development.

Texas water

Texas has dominated shale gas production in the U.S. over the past decade. The Barnett Shale was the sole producer in the early 2000s and accounted for about 66% of the U.S. shale gas production from 2007 to 2009 (Nicot 2012). Texas is subject to drought and wet period cycles that might become extreme with climate change and impact the water available. Water requirements are reported to the RRC of Texas. Surface water is owned and managed by the State and requires a water-right permit for diversions. Groundwater is owned mostly by landowners, but is generally managed by legislatively authorized groundwater conservation districts (Nicot 2012). Groundwater is generally available in each of the shale gas plays, and unlike surface water, groundwater is located close to production wells.

Barnett Shale, TX

The Barnett Shale is located in central Texas around the Dallas-Ft. Worth area. Precipitation is variable across the state of Texas. The mean annual precipitation in the Barnett area is about 790 mm per year (Nicot 2012). About 60% of the water used in hydraulic fracturing operations in the Barnett Shale play comes from groundwater sources, specifically the Trinity and Woodbine aquifers in North Central Texas (Andrew et al. 2009). The Trinity Aquifer extends from south-central Texas to southeastern Oklahoma, and groundwater use varies across the Barnett Shale development area. For example, groundwater provides about 85% of total water supply in Cooke County, but only 1% for Dallas County (Andrew et al. 2009). Extensive development of the Trinity Aquifer in the Dallas-Ft Worth metropolitan area had caused groundwater levels to drop more than 500 feet in some areas (Andrew et al. 2009). For many rural areas, groundwater from the Trinity Aquifer remains the sole water source. Water use can vary widely from county to county depending on the pace of shale gas development. Municipal water use is dominant (greater than 85%) in the footprint of the Barnett Shale play in Denton and Tarrant counties; elsewhere, water use is mixed with some irrigation and manufacturing (Nicot 2012). Surface water is available in the Barnett Shale area, including major rivers and reservoirs; however, population growth is expected to increase demand for water resources and cause increasing competition. It is predicted that the net water use for shale gas production in the Barnet Shale play will increase from 1%–40% at the county level for selected counties (Nicot 2012).

Eagle Ford Shale, TX

The Eagle Ford Shale play is located in South Texas. The mean annual precipitation in the Eagle Ford Shale is about 740 mm per year (Nicot 2012). Surface water in the Eagle Ford Shale region is not as readily available and abundant as the northeast sections of Texas. A small portion of the Rio Grande River at the Mexican border is used, and several streams are ephemeral and recharge underlying aquifers. However, even when surface water is available, it is often not located adjacent to sites; therefore, trucking and piping of water is often required. Operators rely mostly on groundwater from the Carrizo Aquifer, though groundwater has already been partially depleted for irrigation in the Winter Garden region of South Texas (Nicot 2012). Over-extraction of groundwater for irrigation in the past limits water availability for current and future shale gas production (Nicot 2012). Water used in south Texas is variable; municipal water use is dominant (greater than 85%) in the footprint of the Eagle Ford in Web County (Nicot 2012). It is predicted that during the peak years of production, the net water use for shale gas production in the Eagle Ford Shale region will increase from 5% to 89% at the county level for selected counties (Nicot 2012).

Haynesville Shale, LA

The Haynesville Shale is located in East Texas and western Louisiana. The eastern part of Texas has high precipitation, with a mean annual precipitation of 1,320 mm per year, resulting in a widespread and abundant supply of surface water (Nicot 2012). The region also hosts large aquifers, specifically, the Carrizo Wilcox and Queen City/Sparta Aquifers. Shale gas production in Louisiana relies heavily on local groundwater from the Carrizo Aquifer and currently derives about 75% of the water from surface water or lesser-quality shallow groundwater (Nicot 2012). The groundwater is more readily available in East Texas, with the only competition for water use being industrial and municipal demands (Nicot 2012). Furthermore, it is predicted that during the

peak years of production, the net water use for shale gas production in the Haynesville Shale region will increase from 7% to 136% at the county level for selected counties (Nicot 2012).

San Juan Basin, CO

The San Juan Basin is located in the arid Southwest U.S., occupying the Four Corners area of Colorado, New Mexico, Arizona, and Utah. The basin is characterized by a wide range of topographic settings that include valleys, canyons, badlands, uplands, mesas, and buttes (Haerer 2009). Precipitation in the San Juan Basin varies regionally. Annual precipitation in the high mountain areas in Colorado can receive as much as 1,020 mm per year, whereas annual precipitation in lower altitudes of the central basin in New Mexico can receive less than 200 mm per year (Levings 1996). Runoff water from snow and precipitation, which flows into rivers such as the San Juan River, makes up a large portion of the surface water. However, because of high evaporation rates and the hot and dry climate of the Southwest, surface water in the basin is limited and has already been fully appropriated.

Thus, groundwater resources tend to be the only source of water in most of the basin, and they are used mainly for municipal, industrial, domestic, and stock purposes (Levings 1996). The San Juan structural basin is a major oil and gas producing area, and groundwater is produced as a byproduct of these operations (Levings 1996). Several major aquifers exist in the basin; most are unconfined and located within the Tertiary formations (Haerer 2009). The amount of available water varies, depending on the underlying geological rock formations. For example, the Fruitland Formation and Pictured Cliffs Sandstone are aquifers that are sources of drinking water along the northern margin of the basin and act as a single hydrologic unit. The Ojo Alamo Sandstone is the primary aquifer for the southern margins and is a possible source of groundwater (EPA 2004). Groundwater levels in the Fruitland Formation have declined significantly due to the development of energy resources in the San Juan Basin (Levings 1996).

Green River Basin, WY

The Green River Basin is located in the southwest corner of Wyoming, northwest Colorado, and northeast Utah. The basin drains to the Green River, a major tributary to the Colorado River. On average, the basin receives about 250–400 mm of precipitation annually and less than 13% of the basin receives more than 500 mm (WWDC 2010). Precipitation is highest during the months of April and May and the least in December and February. There are four regional aquifer systems in the Wyoming side of the Green River Basin. The Cenozoic, Mesozoic, Paleozoic, and Precambrian aquifer systems range from the youngest and most heavily used to the oldest and least used, respectively (WWDC 2010). There has been relatively little development of groundwater resources in the Green River Basin, and the recent increase in shale oil and gas development has relied on groundwater resources as the primary supply to the industry. In Wyoming, irrigated agriculture is the largest water consumer. However, the energy and mineral sectors have historically added volatility in water use and allocation, requiring large amounts of water (WWDC 2010). Groundwater in the basin is used for domestic and pubic supplies, and industrial uses including mining and irrigation. Oil and gas development has increased substantially in the Green River Basin and accounts for a large part of the increase in groundwater use (WWDC 2010).

3.3.1.2 Current Water Quantity Risks Resulting from Industry Activities

Risks to water quantity resulting from industry practices in shale gas development include reductions in both available surface water and groundwater. These risks occur in the areas from which water resources are sourced, not necessarily the hydraulic fracturing site. In areas where the levels of the groundwater table are already affected by multiple sectors' uses (e.g., agriculture, municipal water supply), large increases in use by any sector might affect water availability or the cost of pumping for all other users.

The water quantity risk to any given water basin depends on how much water is used and on the local water availability. Water usage in shale gas development, as described above, depends on the total number of wells, water use per well, and recycling rate. Water availability depends on local geologic and climatic conditions and on competing users of water. In the study regions, the total number of producing wells has been increasing steadily since 2008. With the exception of Pennsylvania, there are no data indicating a substantial increase in the recycling rate of wastewaters, and the total quantities of freshwater used for hydraulic fracturing have been increasing. The impact of recycling on reducing freshwater demands is limited by the amount of flowback and brine produced from each well. The use of non-freshwater sources, such as shallow brackish waters, could alleviate demands on freshwater; but there are no readily available data on availability or current usage of these water sources for shale gas operations.

Values of total water available physically and legally can be difficult to quantify, but our report analyzes the water usage of oil, gas, and mining activities as a percentage of all other existing water uses. On a state level, the amount of water currently withdrawn for hydraulic fracturing is a relatively minor fraction of total water withdrawals. In Colorado for example, total water diversions for hydraulic fracturing represent only 0.1% of all water diversions in the state (COGCC 2012b). In Texas, mining activities, which include hydraulic development, accounted for just 2% of total water withdrawals in 2011 (TDWB 2012).In Texas and Colorado, irrigation accounts for more than 55% and 85%, respectively, of total water withdrawals (COGCC 2012b; TDWB 2012).

Greater insights into risks to water resources can be gained by analysis on a geospatial scale smaller than the states, such as the county level. In many counties where shale gas development sites are located, mining activities already account for a substantial percentage of existing water usage (Figure 20) (Kenny et al. 2009).

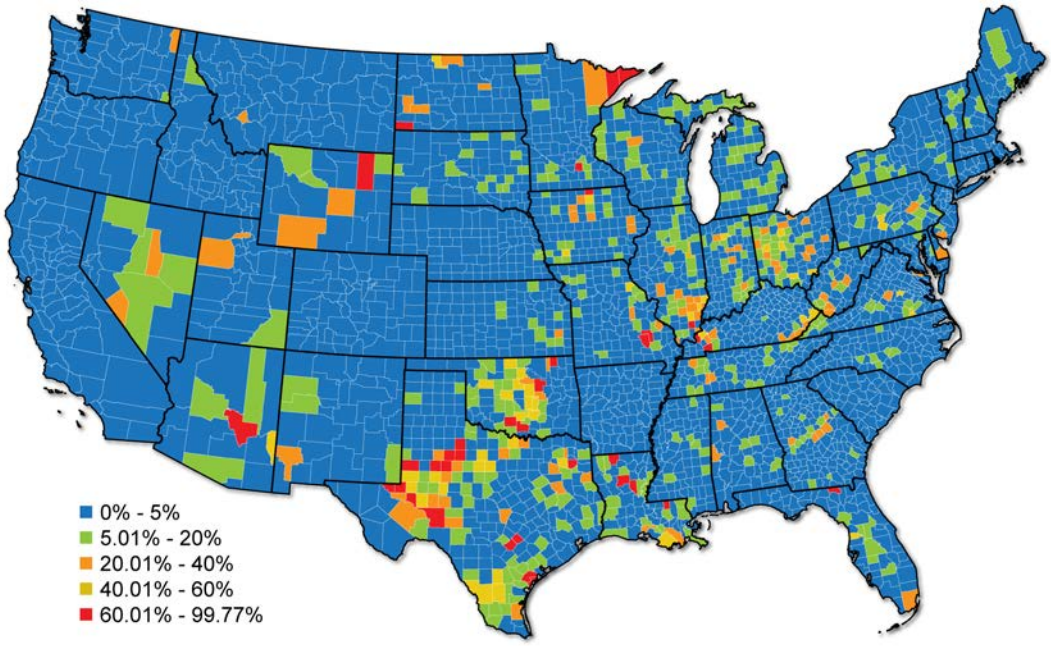

Figure 20. Mining water withdrawals as a percent of total water withdrawals, 2005 (Kenny 2009).

In 2005, mining activities in Texas counties that overlapped with the Barnett, Eagle Ford, and Haynesville formations accounted for a large percentage of total water withdrawals. Similarly, counties in Louisiana overlapping with the Haynesville formation, counties in New Mexico overlapping with the Barnett and San Juan formations, and counties in Wyoming overlapping with the Green River formation show that mining activities account for water withdrawals representing 5% to over 60% of total withdrawals in that county. Thus, water use for mining activities already represents a substantial portion of total water usage in the regions where shale gas development is occurring. Rapid expansion of water required for hydraulic fracturing could impact local water availability, depending on water resources in each region. Further research is needed to evaluate the impact that the current and projected water use for mining activities, including hydraulic fracturing, could have on the water resources and other water demands in these regions.

3.3.2 Risks to Water Quality

3.3.2.1 Current Industry Activities Affecting Water Quality

Risks to water resources depend on well and drilling construction practices, handling of chemicals on site, and wastewater management. Risks to water quality can occur at both the location of hydraulic fracturing and where water is stored or treated.

Onsite well-construction and hydraulic fracturing practices

In terms of risk to water resources, well design and construction phase is a crucial component of the hydraulic fracturing process. Proper well construction can separate the production operations from drinking water resources. Well construction involves drilling, casing, and cementing—all of which are repeated multiple times until a well is completed. Drilling is conducted with a drill bit, drill collars, drill pipe, and drilling fluid such as compressed air or a water- or oil-based liquid (EPA 2011). Water-based liquids typically contain a mixture of water, barite, clay, and

chemical additives (OilGasGlossary.com 2010). Once removed from the well, drilling liquids and cuttings must be treated, recycled, and/or disposed of.

Casing is steel pipe that separates the geologic formation from the materials and equipment in the well, and that also provides structural support. The casing is designed to withstand the external and internal pressures during the installation, cementing, fracturing, and operation of the well. Some operators might forego casing, in what is called an open-hole completion, if the geologic formation is considered strong enough structurally to not collapse upon itself. Casing standards vary regionally and are set by state regulations. Once the casing is in place, a cement slurry is pumped down the inside of the casing and forced between the formation and the casing exterior. The cement serves as a barrier to migration of fluids up the wellbore behind the casing, as well as a structural support for the casing. The cement sheath around the casing and the effectiveness of the cement in preventing fluid movement are the major factors in establishing and maintaining the mechanical integrity of the well; however, even a properly constructed well can fail over time due to stresses and corrosion (Bellabarba et al. 2008). For a given well, there may be multiple levels of drilling, casing, and cementing to prevent contamination of local water resources (Figure 21).

Once the well is constructed, the formation is hydraulically fractured. The hydraulic fracturing occurs over selected intervals where the well is designed to permit fluids to enter the formation. Hydraulic fracturing fluids, by volume, are mostly water and propping agents such as sand, designed to facilitate the fracturing and keep the new fractures open.

The chemicals present in hydraulic fracturing fluids can react with naturally occurring substances in the subsurface, causing these substances to be liberated from the formation (Falk et al. 2006; Long and Angino 1982). These naturally occurring substances include formation fluids (brine), gases (natural gas, carbon dioxide, hydrogen sulfide, nitrogen, helium), trace elements (mercury, lead, arsenic), radioactive materials (radium, thorium, uranium), and organic materials (organic acids, hydrocarbons, volatile organic compounds).

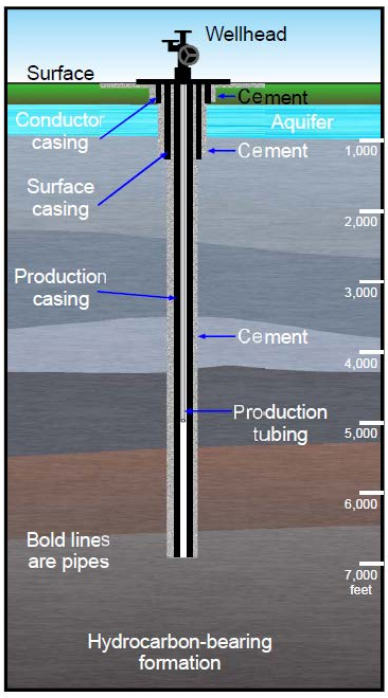

Figure 21. Schematic of well that includes several strings of casing and layers of cement (EPA 2011)

Once a well is no longer producing gas economically, it can either be re-fractured or plugged, to prevent possible fluid migration that could contaminate soils or waters (API 2009). A surface plug is used to prevent surface water from seeping into the wellbore and migrating into groundwater resources.

Onsite handling of chemicals

The chemicals used in fracking fluids are often mixed together on site with the propping agent (usually sand) and water. The types of chemicals and their volumes might vary from site to site and from developer to developer, depending on formation properties and developer common practices. Chemicals are stored on site in tanks before mixing and hydraulic fracturing operations begin. In general, 0.5% to 2% of the total volume of fracking fluid is made up of chemicals (GWPC and ALL Consulting 2009). The composition and relative amounts of chemicals might change from site to site. Table 6 provides an example of the variety and amounts of chemicals that comprise fracking fluid, where chemicals contribute 0.5% of the volume.

Table 6. Example Composition of Hydraulic Fracturing Fluids (GWPC and ALL Consulting 2009; API 2010)

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Water		Deliver proppant	90	2,970,000
Proppant	Silica, quartz sand	Keep fractures open to allow gas flow out	9.51	313,830

[131] Based on the average water use per well identified in this study, 3.3 million gallons

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Acid	Hydrochloric acid	Dissolve minerals, initiate cracks in rock	0.123	4,059
Friction Reducer	Polyacrylamide, mineral oil	Minimize friction between fluid and pipe	0.088	2,904
Surfactant	Isopropanol	Increase viscosity of fluid	0.085	2,805
Potassium Chloride		Create a brine carrier fluid	0.06	1,980
Gelling Agent	Guar gum, hydroxyethyl cellulose	Thicken fluid to suspend proppant	0.056	1,848
Scale Inhibitor	Ethylene glycol	Prevent scale deposits in pipe	0.043	1,419
pH Adjusting Agent	Sodium carbonate, potassium carbonate	Maintain effectiveness of other components	0.011	363
Breaker	Ammonium persulfate	Allow delayed breakdown of gel	0.01	330
Crosslinker	Borate salts	Maintain fluid viscosity as temperature increases	0.007	231
Iron Control	Citric acid	Prevent precipitation of metal oxides	0.004	132
Corrosion Inhibitor	N,N-dimethyl formamide	Prevent pipe corrosion	0.002	66
Biocide	Glutaraldehyde	Eliminate bacteria	0.001	33

In this example, we consider the average water use per well as identified in this study to be 3.3 million gallons. Therefore, the total volume of chemicals used—0.5% of the fracking fluid volume—is about 16,500 gallons per well. The total average volume of chemicals used in hydraulic fracturing fluids ranges from 5,500 to 96,000 gallons per well, given the wide range of water use per well, in addition to the chemical composition (Table 7).

Table 7. Estimates of Total Gallons of Chemicals Used per Well

	4.6 million gallons per well (average estimate)	2.3 million gallons per well (low estimate)	7.3 million gallons per well (high estimate)
Lower bound of chemical composition (0.5% of volume)	16,500 gallons	5,500 gallons	24,000 gallons
Upper bound of chemical composition (2.0% of volume)	66,000 gallons	22,000 gallons	96,000 gallons

Wastewater management practices

After hydraulic fracturing operations, pressure decreases and fluids return to the surface before the well begins formal gas production. Although there are no standardized definitions, the used fracking fluids (frac flowback) and naturally occurring water resources (produced water) both return to the surface. In general, the frac flowback returns first at high rates (e.g., ~100,000 gallons per day) for a few days; then produced water surfaces at lower rates for the remainder of the well's lifetime (e.g., ~50 gallons per day). The rates of production and total volumes of frac flowback and produced water vary greatly within and between shale plays—ranging from 10% of original fracking fluid volume to as high as 75% (EPA 2011). Frac flowback and produced water both contain naturally occurring substances, including oil, gas, radionuclides, volatile organic compounds, and other compounds that could contaminate local water resources.

Frac flowback and produced water are stored on site in storage tanks or impoundment pits prior to treatment, recycling, and/or disposal (GWPC 2009).Onsite impoundments can be designed for short-term use (for storage purposes) or for long-term use (evaporation pits), and impoundment regulations and requirements can vary greatly by location.

Operators have a variety of options for managing wastewaters, including recycling and reusing, onsite evaporation in impoundments, onsite injection into wells, disposal at a centralized facility through evaporation or underground injection, and treatment through surface water treatment plants. Overall, national disposal methods are dominated by underground injection (EPA 2011). Current industry practices might vary from state to state, and have shown different trends from 2008 to 2011. For example, Colorado (Figure 22) and Pennsylvania (Figure 23) show stark differences and trends.

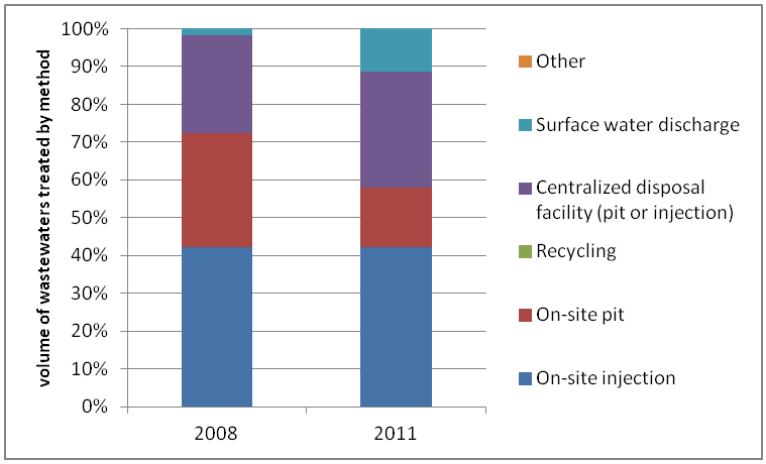

Figure 22. Colorado wastewater treatment methods, 2008–2011 (COGCC 2012a)

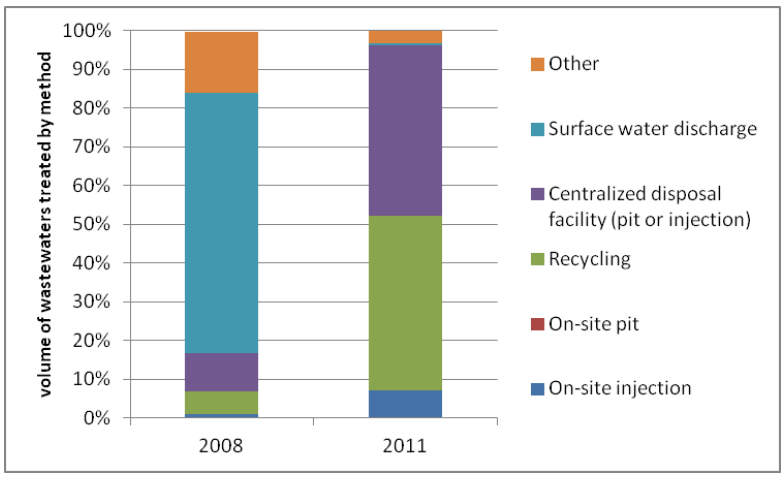

Figure 23. Pennsylvania wastewater treatment methods, 2008–2011 (PA DEP 2012b)

In Pennsylvania, surface water treatment decreased from 67% of total wastewater volumes in 2008 to less than 1% in 2011 (PA DEP 2012b). In contrast, in Colorado, surface water treatment increased from 2% of total wastewater volumes in 2008 to 11% in 2011 (COGCC 2012a). In Pennsylvania, recycling increased from 6% of total wastewater volumes in 2008 to 45% in 2011, whereas there are no data indicating any recycling occurring in Colorado. The dominant disposal method in Colorado remains injecting or evaporating wastewater fluids on site. Onsite disposal methods decreased in Colorado, managing 72% of total wastewater volumes in 2008 to 58% in 2011. In Pennsylvania, onsite well injection increased from 1% of total wastewater volumes in 2008 to 7% in 2011. Both states increased their use of centralized industrial disposal facilities between 2008 and 2011. In Pennsylvania, the use of centralized disposal facilities increased from 10% of total wastewater volumes in 2008 to 44% in 2011. In Colorado, the use of centralized disposal facilities increased from 26% of total wastewater volumes in 2008 to 31% in 2011.

Water disposal methods can change from year to year due to evolving regulations and industry experience. Data from 2008 showed a high percentage of surface water discharge for wastewaters in Pennsylvania; after 2008, there was a sharp decline. This is due to the changes to the Pennsylvania Department of Environmental Protection's (DEP) 25 Pa Code Chapter 95 Wastewater Treatment Requirements. These requirements were changed on April 11, 2009, after total dissolved solids levels were measured far above environmentally healthy levels in 2008 and 2009 (STRONGER, 2010). The high TDS was above drinking water standards in the Monongahela River. The TDS also promoted golden algae growth, resulting in higher toxicity levels in Drunkard Creek, killing over 30 different species of aquatic life. The new regulations required a maximum TDS discharge of 500 mg/L (STRONGER, 2010). This new regulation makes it uneconomical to use municipal water treatment in Pennsylvania because wastewaters can reach up to 360,000 mg/L TDS (USGS 2002b). In addition, injection has remained relatively unfavorable in Pennsylvania because the state has only eight Class II underground injection wells, three of which are commercially owned. The other injection wells are privately owned and only service the companies that own them (Phillips 2011).

Recycling operations can be more expensive than other waste management options. Recycling and reuse of water involves energy for treatment, and costs associated with storing water, transport of water, and transport and disposal of the solid wastes removed from the treated water.

In contrast, injecting wastewater into wells only involves the transport of water to an injection well and fees for the disposal. Recycling options can also be limited by high concentrations of materials that make recycling uneconomic.

3.3.2.2 Current Water-Quality Risks Resulting from Industry Activities

Risks to public water quality resulting from industry practices include risks to both surface water and groundwater sources, and they are not limited to the location of the hydraulic fracturing operation. Risks to surface and groundwater resources exist at each stage of development—well construction and hydraulic fracturing operations, chemical handling, and wastewater management.

Improper well construction or improperly plugged wells are one source of risk by which groundwater contamination can occur (PA DEP 2010b; McMahon et al. 2011). In addition to risks associated with construction integrity, risks are also associated with well durability for wells that are repeatedly hydraulically fractured. The potential exists for fracking fluids, as well as other naturally occurring substances, to reach groundwater sources if well construction or plugging operations are inadequate. The degree of risk will be dependent upon local geology, the composition of the chemicals and naturally occurring substances, and the mobility of the substances within the formation.

Another source of risk during the hydraulic fracturing operation in coalbed methane (CBM) reservoirs is the potential for the fractures to extend into aquifers or into pre-existing faults or fractures (natural or man-made) that might directly extend into aquifers. Currently, it is difficult to predict and control fracture location and lengths, and the overall risk will depend on the local geology and fracking practices used. In shale gas formations, decreasing pressure gradients and natural barriers in the rock strata serve as seals for the gas in the formation and also block the vertical migration of frack fluids (GWPC and ALL Consulting 2009). In contrast, CBM reservoirs, such as the North San Juan considered here, are mostly shallow and may also be co-located with drinking water resources. In CBM areas, hydraulic fracturing operations near a drinking water source might raise the risk of contamination of shallow water resources from hydraulic fracturing fluids (Pashin 2007; EPA 2011).

Another risk to water quality is the handling and mixing of chemicals on site. Risks include spills or leaks that might result from equipment failure, operational error, or accidents. Leaked chemicals could be released into bodies of surface water or could infiltrate groundwater resources. There have been reports of surface spills of hydraulic fracturing fluids; however, little is known about the frequency, severity, and causes of these spills (Lustgarten 2009; Lee 2011; Williams 2011). The risks to local water resources will depend on the proximity to water bodies, the local geology, quantity and toxicity of the chemicals, and how quickly and effectively clean-up operations occur.

Wastewater management practices have risks to water quality that potentially affect water resources both on and off site of the location of the shale gas development operations. Considering risks on site, spills of frac flowback or produced water could contaminate local surface and/or groundwater resources. In addition, there could be equipment failures (e.g., poorly constructed impoundments) during onsite wastewater storage prior to treatment. Potential offsite risks include spills or leakage that might occur during the transport of wastewaters to the location

where they will be treated. If surface water treatment is used, there is a risk of the surface water treatment plant not having the capabilities to fully treat the wastewater before it is released back into the hydrologic cycle (Puko 2010; Ward Jr. 2010; Hopey 2011).

From 2009 to 2011, Pennsylvania had 337 reported violations that were classified as "minor effect" or "substantial effect" (NEPA 2012). Violations of these types include the release of wastes or produced water on site in amounts less than 10 barrels (420 gallons). From 2009 to 2011, Texas had 14 reported "minor effect" or "substantial effect" violations, and one reported "major effect" violation. "Major effect" violations include large spills or improperly disposed of wastes greater than 10 barrels (420 gallons), small to large spills that were moved off site and impacted a resource such as a drainage ditch or wetland, and any spill of fracturing fluid greater than 1 barrel (42 gallons). For Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Also, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired, and data for violations in other states were not available. More detailed information about violations in states where data are available is listed in Appendix D. Further research is needed to fully determine the severity and cause of the reported violations.

3.4 Data Availability and Gaps

Substantial gaps in data availability prevent a full assessment of risks to water resources resulting from shale gas operations. Only certain statistics are publicly available for each region, and in some regions that cross state boundaries, information is only available for the part of a play that is in one state (Table 8.)

Table 8. Overview of Data Availability

		CO	NM	PA	NY	TX	TX	LA	WY
	Risk Factor or Analysis Metric	**North San Juan**	**North San Juan**	**Marcellus**	**Marcellus**	**Barnett**	**Eagle Ford**	**Haynesville**	**Upper Green River**
1	Disposal methods/volumes	◊		◊	◊				^
1a	Fraction of water recycled	◊		◊					
2	Fresh water use	^	^	◊		^	^	◊	^
2a	*Fracturing water*	◊		◊		◊	◊	◊	◊
2b	*Source permitting*	^		◊		^	^	^	^
3	PW/FF volumes	◊		◊		^	^	^	
3a	*Injected volumes*	◊				^	^	◊	◊
4	State regulations					◊			
4a	*Rule violations*			◊					
5	Regional water use			◊					
6	Total wells			◊		^	◊		
6a	*% Horizontal*			◊			◊		
Key									
◊	Data available								
^	Partial data available								

Comprehensive analyses of water risks are hindered by a lack of reliable, publicly available water usage and management data. Data are not publicly available for many regions for total water withdrawals, total wells drilled, water recycling techniques, wastewater management, and other management practices. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; but further efforts are desired. Data collection and availability could improve with further collaboration and interaction with industry stakeholders, as well as other stakeholders.

3.5 Best Management Practices (BMP)

Various attempts have been made to define best practices for water management (e.g., IEA 2012; Energy Institute 2012; ASRPG 2012; Chief O&G 2012; SEAB 2011; API 2010). Based on these reports, the following are best practices that are generally accepted to be important for understanding and minimizing risks related to water quantity and quality:

3.5.1 Monitoring and Reporting

- *Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.* There is little information on the management of fracturing water from acquisition to disposal or recycle, both in terms of quality and quantity.

- *Adopt requirements for baseline water-quality testing.* Background testing is recognized for its value, but is often not standardized. Better guidance is needed for statistically defensible testing.
- *Fully disclose hydraulic fracturing fluid additives.* Disclosure of fracturing fluid chemicals on fracfocus.org is now in place in Colorado, Wyoming, and Texas and is being considered in several other states.

3.5.2 Water Quantity

- *Recycle wastewaters.* Freshwater demand can be minimized by treatment and reuse of produced water and frac flowback. Flowback water produced in the hydraulic fracturing process is returned at relatively high flows and might contain more chemicals of concern than produced water. Optimized handling of this fluid is important for mitigating risks to water quality and quantity because it can lessen the need for transport and wastewater disposal.

3.5.3 Water Quality

- *Use a closed-loop drilling system.* In closed-loop drilling processes, contaminated water is not exposed to air or pits where it could leak, thus eliminating the storage of discarded drilling fluids in open pits at the drilling site.
- *Eliminate flowback water mixing with fresh water in open impoundments.* Disposing of untreated flowback water in reservoirs containing fresh water to be used for hydraulic fracturing increases the risk of harmful spills or leaks.
- *Use protective liners at pad sites.* The use of liners or other protective devices at pad sites can contain minor spills and prevent environmental contamination. Proper collection and disposal equipment is also important to have on site.
- *Minimize use of chemical additives and promote the development and use of more environmentally benign alternatives.* "Green" hydraulic fracturing fluid has been developed—based on fluid mixtures from the food industry—that do not impair groundwater quality in the case of an inadvertent leak or spill.

A next step in developing BMPs for reducing risks to water resources in shale gas development is to evaluate the efficacy of each of the above BMPs (Kemp 2012; Energy Collective 2012). Currently, little or no data exist that analyze the effectiveness or cost-benefit tradeoffs of these BMPs. Further examination of BMPs could assist developers in evaluating important water management questions—such as whether installing protective liners at pad sites or reducing use of chemical additives would have a greater impact on reducing risks to water resources in their regions. A first step in this direction would be to develop a methodology for quantifying and comparing current water-management practices with potential risks.

In many cases, BMPs might be more appropriate or cost-effective for certain geological conditions than others. A further area of needed research is to evaluate the extent to which certain BMPs are applicable or effective across multiple types of formations. To better address this question, researchers could engage a variety of stakeholders—including industry, regulators, researchers, environmental groups, and the public—to understand what practices are currently in use, how effective they are at reducing the risk of water impacts, and where improvements are needed.

A major challenge facing some of these BMPs is that there are no national or state-level disclosure initiatives to track or evaluate the success of their implementation. For example, it is difficult to determine how many operators are currently employing (and with what success) the widely discussed BMP to use closed-loop drilling practices because operators are not required to report this information. Absent such reporting, data collection efforts would likely require close collaboration with multiple industry partners operating in a variety of locations, and this could be time-intensive.

3.6 Summary

We used publicly available datasets to provide an initial evaluation of water risks associated with hydraulic fracturing in six natural gas plays in the United States. Data were limited in every region; continued efforts to catalogue and publish water data will improve future analyses.

Hydraulic fracturing operations have the potential to impact water resources. One of the impact risks associated with water is regional resource depletion due to the use of fresh water during hydraulic fracturing. Water-use data were collected for five of the six regions with average use per well ranging from 1.1 to 5.8 million gallons, with a multi-region average of 3.3 million gallons per well. Total water usage can be estimated by determining the average water use per well, number of wells, and recycling rate; this total freshwater demand value can be compared with estimates of local water availability. Hydraulic fracturing demands are a small fraction of total state water demands, but they can be a substantial portion of water demands in the counties in which the hydraulic fracturing operations are active. If water must be transported from off site to a hydraulic fracturing site, water quantity risks might extend to counties where hydraulic fracturing is not occurring. In all regions considered, the number of wells drilled for hydraulic fracturing has increased each year since 2009. Recycling rates have increased significantly in Pennsylvania since 2009, when the state issued new regulations regarding the treatment of wastewaters.

A second impact risk associated with water is degradation of surface and groundwater quality. Water-quality impacts are a risk during the well construction, hydraulic fracturing, mixing of chemicals, and the wastewater management of shale gas development. As noted above, hundreds of substantial or major violations have been reported that have resulted in spills of produced water, frack fluids, or chemicals. However, it is not clear if water resources have been contaminated—and if so, to what extent—or by which pathway the spills occurred.

A better understanding of the potential contamination pathways (listed here) and their impacts to water resources could assist in identifying and evaluating the phases of operation that have the highest risk of impacting water quality. Potential contamination pathways during well construction and hydraulic fracturing are improper well construction, well degradation from repeated use, lengthy fractures, and improper well plugging. Potential contamination pathways during the mixing of chemicals phase are spills, accidents, and storage equipment failures. Potential contamination pathways at the hydraulic fracturing site during the management of wastewaters are onsite storage equipment failures and spills. Additional contamination pathways and risks occur during the transport of wastewaters to disposal facilities and the potential stress put on surface water treatment plants that might not be capable of treating the types of wastes produced from hydraulic fracturing operations.

Currently, a variety of BMPs are being employed in different regions to minimize risks to water resources. However, there is uncertainty in the industry concerning BMP transferability, cost-effectiveness, and risk mitigation potential. In addition, it is unclear to what extent these BMPs are being employed by different operators. Recycling of frac flowback and produced water is an accepted recommended practice, but limited information exists regarding prevalence, methods, and costs. Except for Pennsylvania, recycling data are not available from public databases, so it is difficult to estimate how much water is being reused in these regions.

3.7 Conclusions and Next Steps

Prior efforts, in addition to with this study, have identified the variety of water-related risks and potential contamination pathways resulting from shale gas development. However, existing publicly available data are not sufficient to perform a full risk assessment on a national or regional scale. A comprehensive and actionable risk assessment would require additional analyses, including the following:

- Quantitatively assess the magnitude of the impacts of the contamination pathways discussed in this report.
- Quantitatively assess the probability that the risks discussed will occur, based on existing industry practices.
- Identify the contamination pathways and risks that, at present, are adequately or inadequately addressed by current industry practices.
- Evaluate BMPs in terms of risk mitigation potential, cost-effectiveness, regional transferability, and industry prevalence.
- Evaluate in detail the wastewater recycling practices, including estimates of current recycling rates, estimates of total potential freshwater savings resulting from recycling, and a life cycle assessment (in terms of energy inputs, emissions, and costs) to identify thresholds for deciding whether to dispose of or recycle wastewaters.

The application of systematically developed BMPs could increase the transparency and consistency by which shale gas development occurs, providing benefits to industry and interested stakeholders. Effective BMPs follow from a defined prioritization of risks in the context of other risks. Risk prioritization would be facilitated by greater availability of industry data and current practices. Further collaboration and interaction with industry, and other stakeholders could improve data collection efforts and are a first step in achieving the analysis objectives above. Lastly, water resources are just one category of risk resulting from shale gas development. Future efforts could evaluate water-related risks and BMPs alongside other risks to air, land, and community.

4 Natural Gas Scenarios in the U.S. Power Sector

4.1 Overview of Power Sector Futures

This chapter summarizes results from modeling different U.S. power sector futures. These futures assess key questions affecting today's natural gas and electric power markets, including the impacts of:

- Forthcoming EPA rules on power plants
- Decarbonization options such as a clean energy standard (CES)
- Potential improvements in key generation technologies
- Higher costs for natural gas production assumed to arise from more robust environmental and safety practices in the field
- Expanded use of natural gas outside of the power generation sector.

The simulations were done using NREL's ReEDS model, incorporating findings from Chapters 1, 2, and 3, as applicable, and looking out to the year 2050.

ReEDS is a capacity expansion model that determines the least-cost combination of generation options that fulfill a variety of user-defined constraints such as projected load, capacity reserve margins, emissions limitations, and operating lifetimes. The model has a relatively rich representation of geographic and temporal detail so that it more accurately captures the unique nature of many generation options, as well as overall transmission and grid requirements. It is a power-sector-only model, so special steps were taken to consider the feedback effects of natural gas demand in other sectors of the economy. These steps, along with additional details about the model, are more fully described in Appendix E of this report.[132]

The scenario analysis presented here is not a prediction of how the U.S. electricity sector will evolve in the future—rather, it is an exercise to compare the relative impacts of different scenarios. Three Reference scenario cases are used as points of comparison for other scenarios based on policy, business, or technology change:

1. Baseline – Mid-EUR
2. Baseline – Low-EUR, and
3. Baseline – Low-Demand.

The modeling team explored four potential policy scenarios in addition to the Reference scenario:

1. A *Coal scenario*, driven by a combination of forthcoming EPA rules, low-cost natural gas, and the age of existing coal generators. Specifically, this scenario addresses the

[132] A full description of the model is also available at: http://www.nrel.gov/analysis/reeds/pdfs/reeds_documentation.pdf.

question of what new capacity will need to be built if and when coal plants retire, and what impacts would result from proposed NSPS.

4. A *CES scenario* with carbon mitigation sufficient for the U.S. power sector to contribute its share in lowering emissions to a level that many scientists report is necessary to address the climate challenge (IPCC 2007; C2ES 2011). This simulates a CES similar to that proposed by Senator Jeff Bingaman, but analyzes impacts through 2050 (EIA 2012a).
5. An *Advanced Technology scenario* where several different generation options—nuclear, solar, and wind—achieve cheaper and thus more widespread deployment; and
6. A *Natural Gas Supply-Demand Variation scenario* for natural gas, aimed to simulate the impact of (1) steps taken to incrementally address environmental and safety concerns associated with unconventional gas production, and (2) significant growth in natural gas demand outside the power sector (Dash-to-Gas). In both cases, the incremental cost of securing natural gas for power generation results in different power sector futures over the long term.

The family of scenarios is summarized in Figure 24.

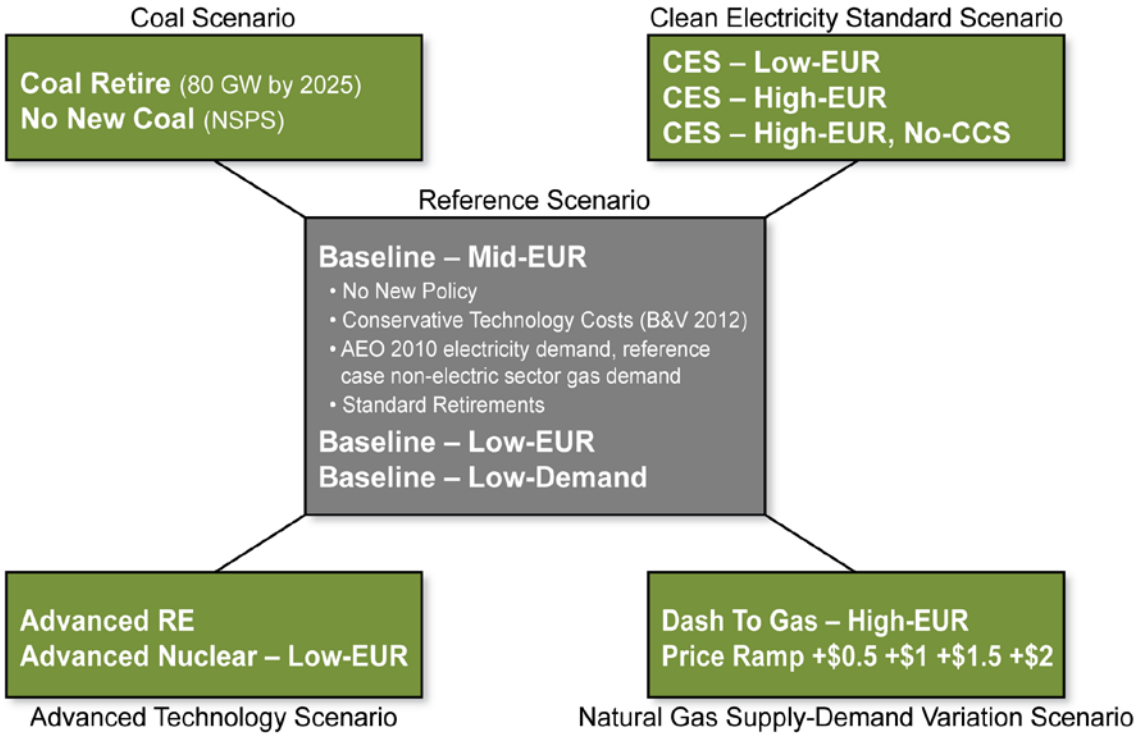

Figure 24. Scenarios evaluated in the power sector futures

4.2 Assumptions and Limitations

Technology cost and performance metrics used in ReEDS are presented in Appendix E. All costs in this study are listed in 2010 dollars unless otherwise noted.

Supply curves were developed to represent natural gas cost to the power sector and the response of this cost to increased power sector demand. The supply curves were developed based on linear regression analyses from multiple scenarios developed by the Energy Information Administration in the Annual Energy Outlook 2011 (EIA 2011).[133] The supply curves represent the price of fossil fuel to the power generators as a function of overall electric sector consumption of the fuel. In particular, as electric sector consumption increases, the marginal fossil fuel price to power generators (and all consumers of the fossil fuel) would increase. Within each year of the ReEDS optimization, the model sees this price response to demand through the linear supply curves. Three sets of supply curves were developed, representing different levels EUR[134] of natural gas. Additional detail on these supply curves is also outlined in Appendix E.

Current renewable tax incentives and state renewable portfolio standards are represented in the ReEDS model. Tax incentives include the modified accelerated cost recovery system for tax depreciation, the production tax credit for utility-scale wind technologies, and the investment tax credit for solar and geothermal technologies.[135] The tax credits are assumed to expire at their legislative end date and not be renewed. In particular, the wind production tax credit expires at the end of 2012, and the solar ITC declines from 30% to 10% in 2016. Although the solar and geothermal investment tax credits have no legislative end date, they are assumed to expire in 2030 as to not influence the long-term expansion decision of the model.

All scenarios evaluated here assume that 30 GW of coal-fired capacity will retire by 2025. The Coal scenario in Section 4.4 considers a higher level of coal retirement and has more detail on the assumed distribution of coal retirements.

ReEDS determines when new high-voltage electricity transmission infrastructure is required and tracks the costs associated with its deployment. It does not track the need to build new natural gas pipeline infrastructure, so those costs are not included in this analysis.

ReEDS is not designed to account for distributed generation; therefore, the penetration of distributed (residential and commercial) rooftop PV capacity was input exogenously into ReEDS from NREL's Solar Deployment Systems (SolarDS) model (Denholm et al. 2009). SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as inputs rooftop PV technology costs, regional retail electricity rates, regional solar resource quality, and rooftop availability. In all cases, except in the Advanced Technology scenario, 85 GW of rooftop PV was assumed to come on line by 2050. This assumption was based on some of the Renewable Electricity Futures (RE Futures) Report 80%-by-2050 renewable electricity scenarios (NREL 2012).

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[133] (EIA 2011). Annual Energy Outlook 2011 scenarios are projections out to the year 2035, and these results are extrapolated to 2050 for use in the ReEDS model. A separate supply curve was developed for each year to represent changes in projected supply and demand interactions as estimated in the multiple Annual Energy Outlook 2011 scenarios. The modeling team had already commenced work by the time the 2012 edition of the Annual Energy Outlook was released, so it could not take advantage of those newer data.

[134] EUR is the amount of natural gas (or petroleum) that analysts expect to be economically recovered from a reservoir over its full lifetime. Three potential measures of EUR are used throughout this study (High, Mid, and Low) to reflect the ranges of optimism and uncertainty over unconventional natural gas availability and price.

[135] Detailed information on these tax incentives can be found on the Database of State Incentives for Renewables and Efficiency at: http://www.dsireusa.org/.

4.3 Reference Scenario

Three different baseline cases were evaluated in the Reference scenario:

- Baseline – Mid-Estimated Ultimate Recovery (Mid-EUR) case, with average power demand growth and a moderate outlook for natural gas prices
- Baseline – Low-EUR case reflecting the potential for more limited—and hence, more expensive—natural gas
- Baseline – Low-Demand case with Mid-EUR expectations. Low demand for electricity could be the result of continued economic stagnation (low gross domestic product [GDP] growth) or successful efforts to curb energy demand through energy efficiency, demand response, smart grid, and other programs to reduce the need for new electricity supply.

A Baseline – High-EUR case was not considered in this family in order to keep the number of results manageable. As noted previously, the Reference scenario is not a prediction of the future U.S. electricity mix *per se*, but instead, it serves as a point of comparison for the other scenarios. Each baseline case in the Reference scenario is summarized in Table 9.

Table 9. Description of Reference Scenario

Case Name	Assumption for Future Electricity Demand	Assumption for Estimated Ultimate Recovery (EUR)
Baseline – Low-EUR	Standard Growth (EIA 2010)	Low-level
Baseline – Mid-EUR	Standard Growth (EIA 2010)	Mid-level
Baseline – Low-Demand	Low Growth (NREL 2012)	Mid-level

Figure 25 and Figure 26 present the projected growth of electric generating capacity and generation for each of the three baseline cases. In the Baseline – Mid-EUR case, total capacity grows from roughly 1,000 GW in 2010 to just over 1,400 GW in 2050. While nuclear and coal capacity decrease as a result of net aged-based retirements, natural gas combined-cycle and natural gas combustion-turbine capacities nearly double, with especially strong growth expected after 2030 when nuclear and coal retirements accelerate. On-shore wind capacity grows steadily from roughly 40 GW in 2010 to nearly 160 GW in 2050, representing about 3 GW of new additions each year on average over the period—a significant reduction from deployment in recent years. In all three baseline cases, oil and gas steam-turbine capacity is fully retired by roughly 2035 due to their low efficiency. Nuclear capacity also declines in all three baseline cases beginning around 2030 as plants reach the end of their operational lifetime and licensing arrangements, and no new plants are built due to uncompetitive economics. As noted above, rooftop PV is not endogenously calculated by ReEDS, but was exogenously assumed for each of the scenarios and baseline cases. Under the technology cost assumptions used, utility-scale PV showed more limited growth compared to natural gas and wind, reaching roughly 10 GW by 2030 and 20 GW by 2050.

The Baseline – Low-EUR case considers a future in which natural gas is less abundant, and thus more expensive, than the Baseline – Mid-EUR case. The primary impact in such a future is less

natural gas capacity and more coal and wind. For example, in this baseline case, the cumulative installed wind capacity reaches about 200 GW by 2050.

In the final Baseline – Low-Demand case, growth in natural gas capacity is affected the most, although wind and coal also see little to no growth.

Considering the associated generation futures in these three baseline cases may be more instructive because capacity alone does not indicate how power plants are operated. Generation from natural gas combined-cycle plants doubles over the 40-year period, growing especially rapidly starting around 2030 because it is used to make up for the retired nuclear and coal generation (see Figure 26). Generation from natural gas combustion-turbine is almost too small to see in these charts, but plays an important role in meeting peak load needs. In the Baseline – Low-EUR case, new coal capacity is added and its generation plays a growing role in meeting power demand after 2030. This new coal is not needed in a low-demand future, and little new wind or other renewable energy generation is needed either.

Figure 27 presents four key metrics for the baseline family of cases. First, natural gas consumption rises 2.5-fold from 2010 to 2050 in the Baseline – Mid-EUR case, but still nearly doubles in the other two cases. Second, average real natural gas prices that generators pay are expected to nearly double by 2050 in the Baseline – Mid-EUR case,[136] while the Baseline – Low-EUR case would see higher prices throughout the period. A Baseline – Low-Demand future will put far less pressure on natural gas prices because they peak at just over $8/MMBtu in 2050. Third, CO_2 emissions from the power sector are expected to remain relatively flat throughout the period. In the Baseline – Low-Demand case, emissions decline significantly as existing coal is replaced with natural gas. Finally, average real prices paid for retail electricity grow steadily through 2050 to roughly $130/MWh in the Baseline – Mid-EUR and Baseline – Low-EUR cases, but are about $15/MWh cheaper in the Baseline – Low-Demand case.

[136] Prices to power generators are higher than well head prices by approximately $1/MMBtu, but vary by region.

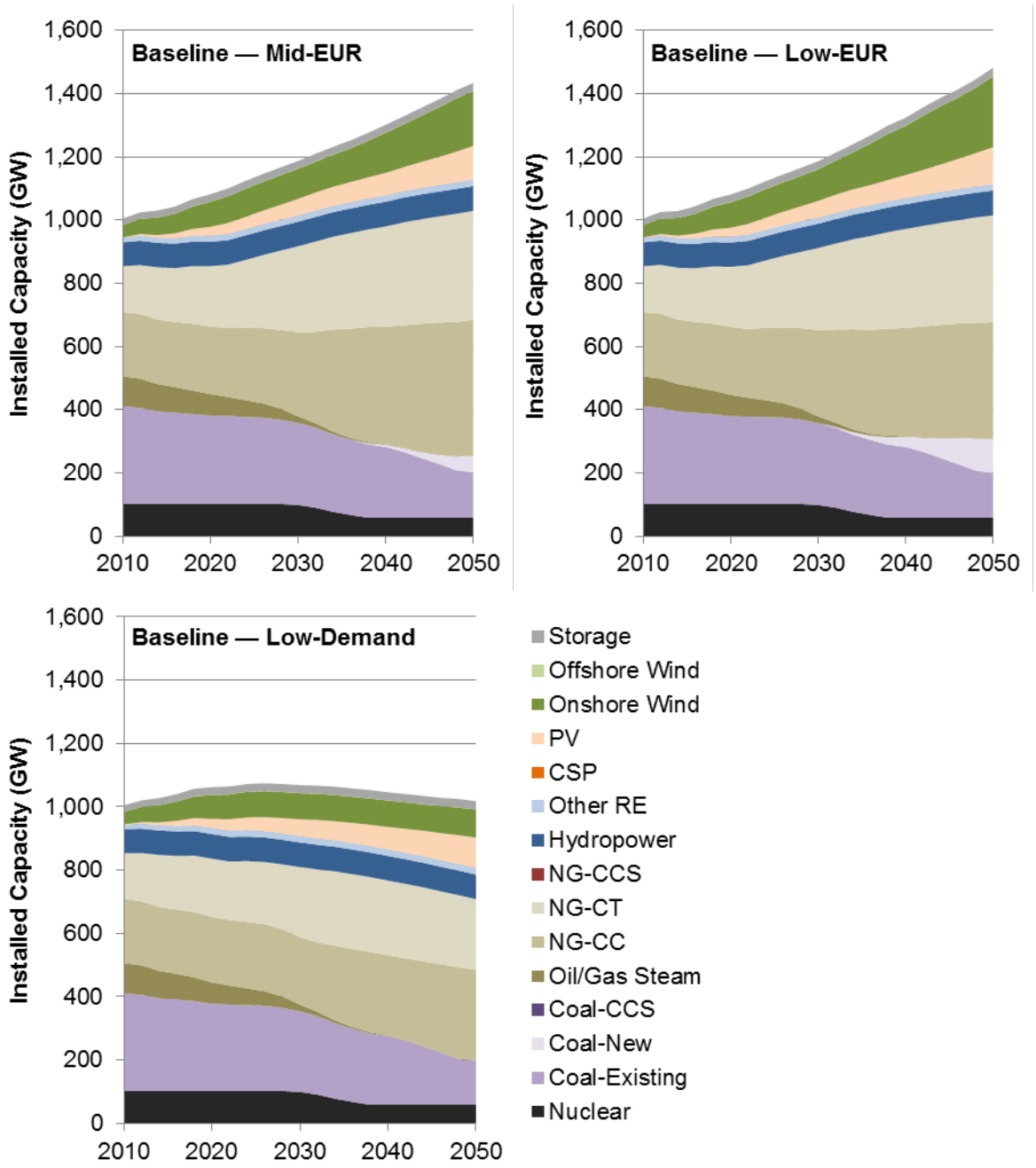


Figure 25. Projected capacity in the Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

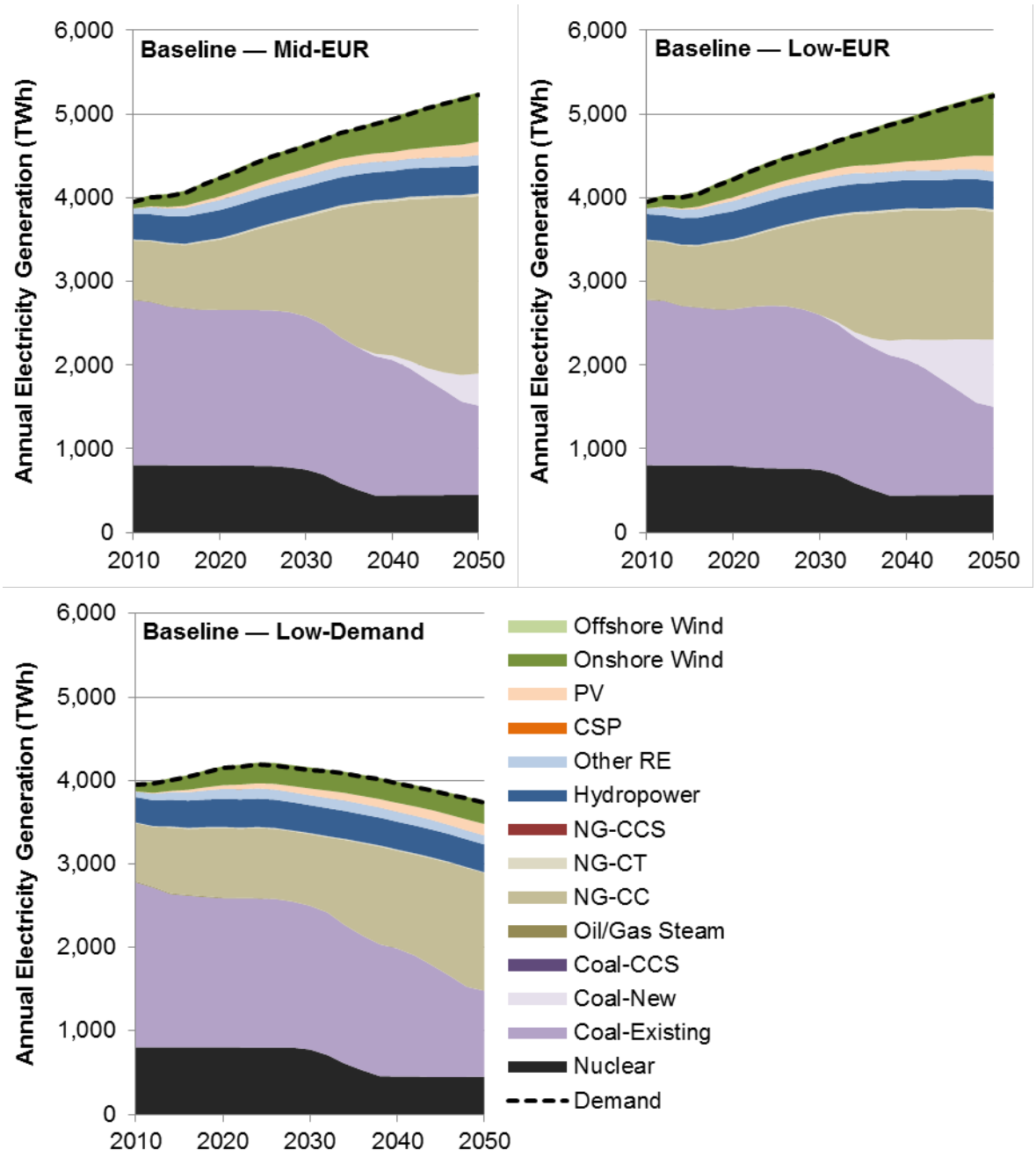


Figure 26. Projected generation in Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

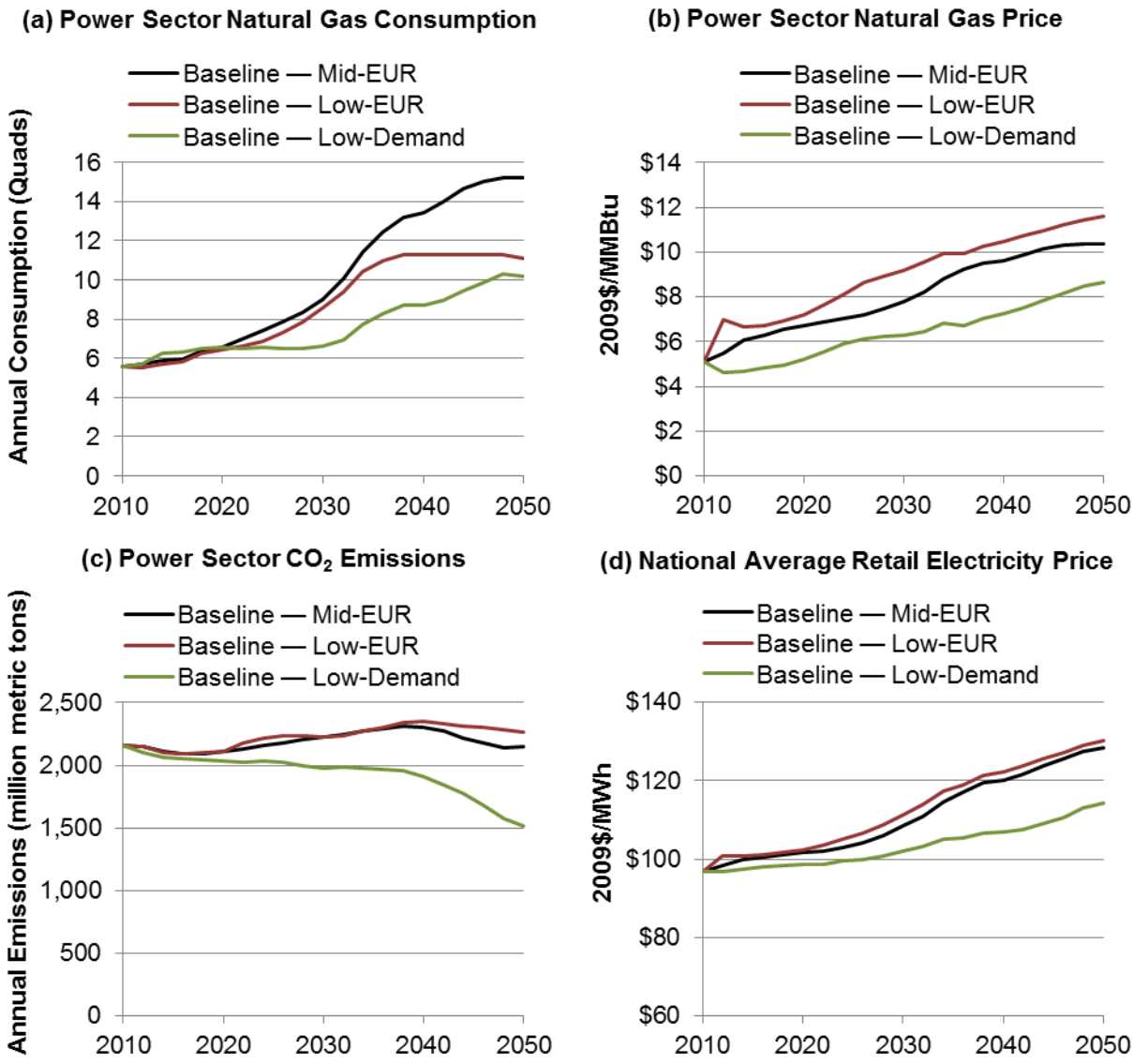


Figure 27. Selected metrics for the Reference scenario, 2010–2050

4.3.1 Implications of Reference Scenario

An electric power future as envisioned in the Baseline – Mid-EUR case would include rapid growth in natural gas generation and less reliance on coal and nuclear power. In effect, natural gas and coal swap positions compared to their historical levels. One concern in such a future is that if volatility returns to natural gas prices after additional new capacity is built—and coal plants are already retired—the economy will be more directly exposed to fluctuating electricity prices. Careful consideration of the benefits and costs of such a shift in generation diversity is warranted.

Although CO_2 emissions do not grow signficantly in such a future, they also do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change. GHG emission reductions of up to 80% by 2050 (compared to 2000 levels)

are considered necessary by most climate scientists to stabilize atmospheric concentrations of GHG and prevent the most serious impacts from a changing climate (IPCC 2007). The Reference scenario results do not put the U.S. power sector on a trajectory to meet this target.

A low power demand future, consistent with recently observed trends,[137] may provide greater generator diversity and prevent a potential over-reliance on natural gas. This Baseline – Low-Demand case also has lower emissions and price impacts, although growth in low-carbon energy deployment slows significantly.

4.4 Coal Scenario

This scenario considers two cases:

- *Coal Plant Retirements case:* The impact of retiring an aggregate 80 GW of coal-fired generation by 2025
- *No New Coal without CCS case:* The impact of not allowing any new coal-fired generating capacity to be built unless it is equipped with CCS technology, which is similar to the proposed EPA New Source Performance Standard rule[138]

As noted previously, the baseline in all scenarios assumes that 30 GW of coal will retire by 2025 due to endogenous age-based rules, plus additional retirements of other aging non-coal-fired plants. Many studies have been published that estimate the potential impact of the forthcoming EPA rules—and increasingly, low-priced natural gas—that are assumed to drive the decision to retire existing plants (Macedonia et al. 2011). A more fundamental reason for retirement may be that about two-thirds of the U.S. coal fleet was built in the 1970s or before (SNL 2011). The two cases evaluated in the Coal scenario are summarized in Table 10. Text Box 2 provides additional information on the EPA rules.

Table 10. Description of Coal Scenario

Case Name	Coal Capacity Retired by 2025 (GW)	Assumption for natural gas Estimated Ultimate Recovery (EUR)
Coal Plant Retirements	80	Mid-level
No New Coal without CCS	30 (same as Reference)	Mid-level

As noted previously, there are two forthcoming EPA rules that are likely to cause many older coal-fired plants to consider either costly retrofits to control pollution or retirement as a more economic solution: the Cross-States Air Pollution Rule and the Mercury and Air Toxics Standard. Two other EPA rules are under development that would attempt to address concerns about (1) water intake structures for cooling purposes at most power plants (the 316(b) rule) and (2) disposal of coal combustion residuals, also known as the coal ash rule.

[137] Total net power generation in the U.S. peaked in 2007, according to EIA statistics, and has not yet returned to pre-recession levels (EIA 2012c).
[138] For additional background on the proposed NSPS ruling, see http://epa.gov/carbonpollutionstandard/.

Text Box 2: Coal Plant Retirements, EPA Rules, and Low-Price Natural Gas

Over the past few years, power sector analysts have debated the impact of new and forthcoming EPA rules on coal plant retirements. These rules include, but are not limited to, the following:

- Cross-States Air Pollution Rule
- Mercury and Air Toxics Standard
- Clean Water Act Section 316(b) cooling water intake structure ruling
- Coal Combustion Residual Rule.

Selected highlights of the rules include:

Cross-States Air Pollution Rule: Limits fine particulate emissions and ozone *transport* in many eastern state power plants by reducing SO_x and NO_x emissions. Compliance options include the installation of low-NO_x burners, catalytic reduction, and scrubbers. The U.S. Court of Appeals struck down this rule in August 2012, and an earlier version known as the Clean Air Interstate Rule will be enforced in its place until EPA redesigns it.

Mercury and Air Toxics Standard: Reduces mercury, acid gases, trace metals and organics emissions at power plants by requiring maximum achievable control technology. Compliance options include scrubbers, filters, and activated carbon injection. Final rule released, and a 3-year compliance period is under way, although legal challenges are also mounting.

316(b): Protects fish and aquatic life from entrapment or entrainment in cooling-water intake structures at power plants. Compliance options include screens, barriers, nets, or cooling towers. The date for issuing the final rule was recently pushed back from July 2012 to June 2013.

Coal Combustion Residual Rule: Establishes standards to manage risk of post-combustion coal waste from power plants. There are two regulatory options under consideration by EPA with different ramifications on power generation cost and impact.

Dozens of studies have been conducted to estimate the impact of these rules on power generators, although most were conducted before the rules were finalized and natural gas prices plummeted in early 2012. Relatively straight-forward financial analysis can be used to determine if it is better to retrofit a power plant so that it can comply with the new rule or retire it. However, real-world decision-making depends on a host of other factors—including future market outlook and plans, portfolio risk management, potential carbon regulations, and reliability assessments.

Some studies anticipated relatively minor impacts from plant retirements (5–20 GW by 2020) (EIA 2011; BPC 2011), whereas others forecast major potential impact and reliability concerns (30–75 GW by 2020) (EEI 2011; CERA 2011; NERA 2011). As of early 2012, about 35 GW of coal-fired generators had already announced that they would retire before 2020. At the same time, as natural gas prices plummeted through 2011 and 2012, generators ramped up operation of natural gas combined-cycle units and scaled back on use of coal generation.

The fuel switching that has already occurred primarily due to low gas prices is equivalent to about 60 GW of coal-fired capacity, although this calculation assumes the coal plants are operated infrequently (32% capacity factor). Most of the oldest coal generators in the U.S. fleet are operated infrequently and have fewer pollution controls. Although fuel switching is a voluntary decision by power generators—and hence, optimized to maximize profits in most cases—the impact of the forthcoming EPA rules will apply different decision-making criteria on top of the inexpensive natural gas driver. Thus, many of the studies conducted to assess the impact of coal plant retirements may need to be redone to account for both drivers of changing generation.

Although most existing studies have anticipated anywhere from 20 to 70 GW of coal retirements by 2020 due to these rules, natural gas price forecasts have fallen below levels that many of the studies used to evaluate the retrofit-retirement decision. The level chosen for this study, 80 GW, is based on these lower natural gas prices and a longer time horizon (2025). *Where* the retirements occur is another important assumption because it will impact whether or not new plants or transmission lines need to be built to replace the lost generation, or if existing natural gas combined-cycle plants can be operated more frequently to meet the load. The retirement distribution chosen was based mainly on the age of existing coal plants and the degree to which they had already installed pollution control devices such as activated-carbon injection and flue-gas desulfurization. Figure 28 displays where existing coal plants were retired, and shows the percentage of coal capacity that is assumed to shut down in each balancing area.

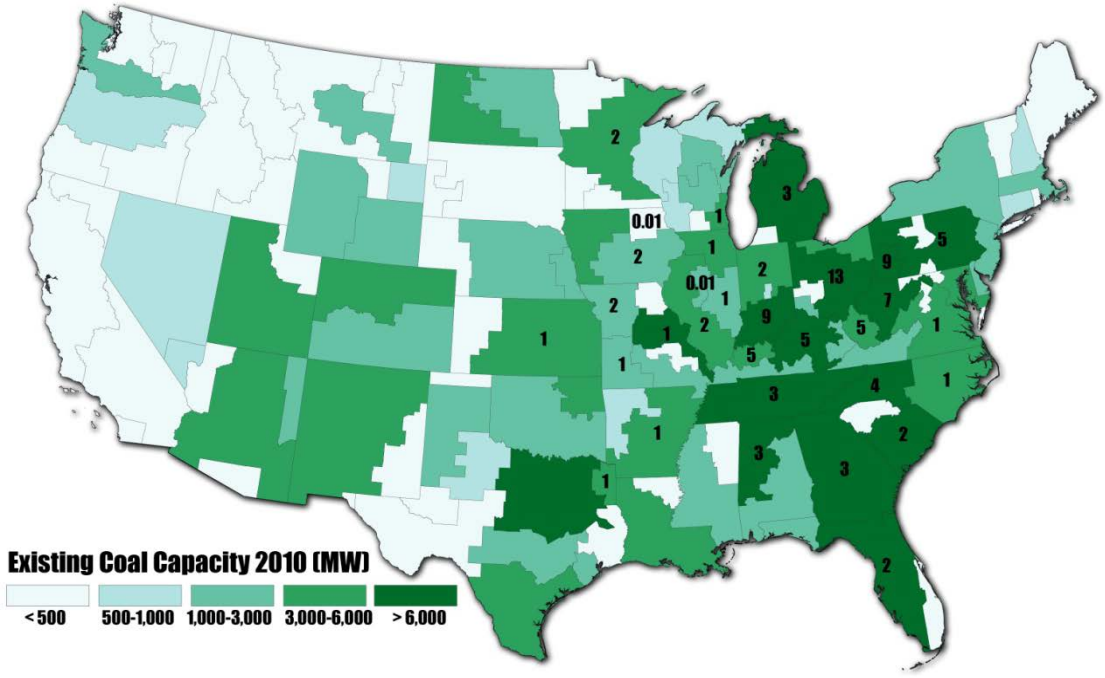


Figure 28. Assumed distribution of retirements in the Coal scenario by percentage of total coal capacity retired in 2025 in each balancing area of ReEDS

The impacts of the two coal cases are summarized in Figure 29 for the years 2030 and 2050. In the Coal Plant Retirements case (where a net 50 GW of additional retirements are seen, compared to the baseline in 2025), most of the retired coal in 2030 is replaced with natural gas combined-cycle, although some additional new wind generation is also added. In the No New Coal without CCS case, there is no difference from the Baseline – Mid-EUR through 2030 because no new coal plants were built by then in the baseline. Cumulative CO_2 emission savings are significant in the Coal Plant Retirements case: 3,300 million tons of CO_2 between 2011 and 2050, even if annual reductions are more modest (see Figure 30). The impact of retirements on average real electricity prices is also modest.

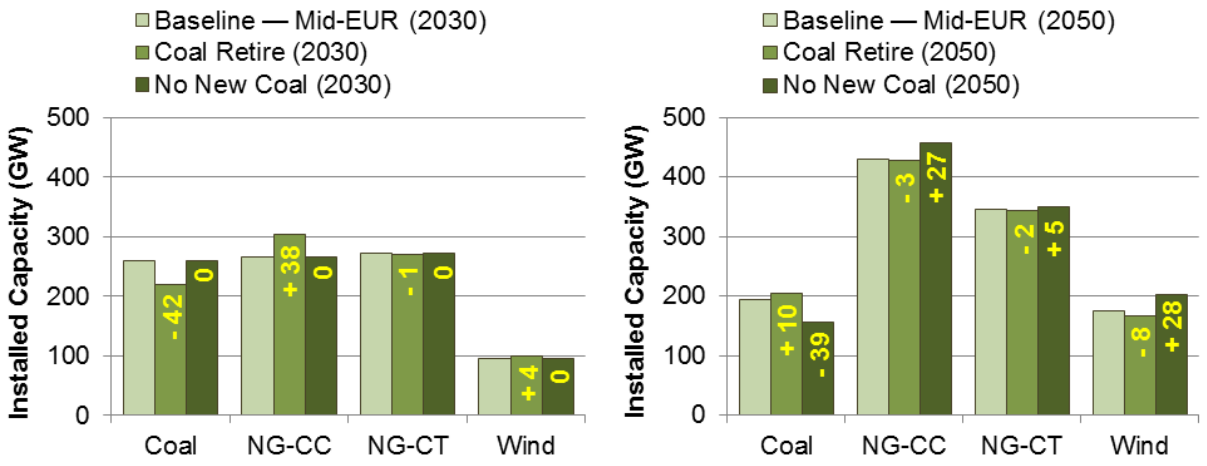


Figure 29. Impacts of coal plant retirements and no new coal without CCS compared to the baseline for 2030 and 2050

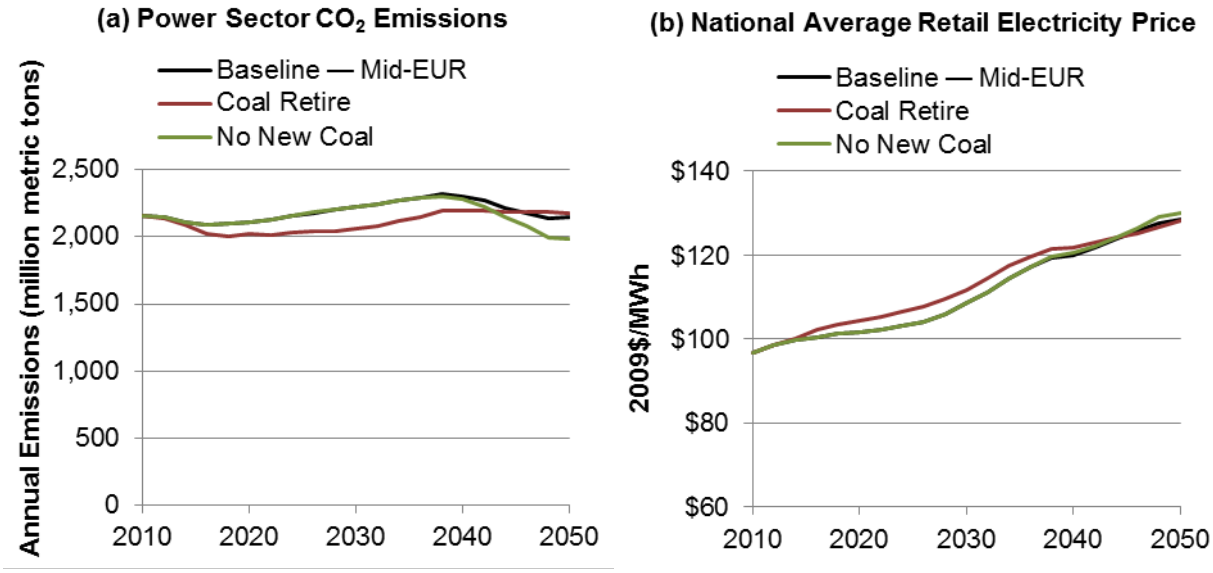


Figure 30. Selected metrics for the Coal cases, 2010–2050

4.4.1 Implications of Coal Scenario Findings

Coal retirements are replaced on a nearly one-to-one basis with natural gas, although wind plays a small role in the early years. In later years, more new coal is built, compared to the baseline, and less wind. In aggregate, however, coal retirements lead to a notable reduction in cumulative CO_2 emissions at relatively modest cost. Initial statistically based analysis does not indicate any difficulty in maintaining adequate reserve margins needed for reliability purposes, although this evaluation is done at a relatively coarse level. A more detailed dispatch model would be required for realistic evaluation of grid reliability issues in such a coal retirement case.

The No New Coal without CCS case, intended to simulate the NSPS, has little impact in early years, but does prevent the construction of new coal after 2030. Compared to the Reference scenario, where new coal does come on line after 2030, the No New Coal without CCS case does

not have any new coal coming on line through 2050 because CCS is not an economic option. In this case, natural gas combined-cycle and wind contribute equally to replace what coal would have been built in the baseline.

4.5 Clean Energy Standard Scenario

After cap-and-trade legislation failed to pass the U.S. Senate in 2010, CES became the preferred vehicle for those decision makers seeking to mitigate GHG emissions in the U.S. power sector.[139] A CES sets targets for the sale of qualifying clean energy generation over time, similar to a renewable portfolio standard,[140] but awards credits roughly based on the relative carbon weighting of emissions compared to standard coal-fired generation (EIA 2012a). In this analysis, new nuclear and renewable generators receive 100% crediting because they have no burner-tip emissions; natural gas combined-cycle generation receives 50% crediting when used without CCS and 95% crediting with CCS; and coal receives 90% crediting, but only with CCS. This analysis follows the current CES legislation under discussion in Congress[141] calling for an 80% clean energy target in 2035, but extends the target to reach 95% by 2050.

Full life cycle GHG emission values could be used in the CES crediting, rather than the current burner-tip estimates, to provide a more representative picture of climate impacts. As discussed in Chapter 1, the current understanding of the full life cycle emissions of unconventional gas is not significantly different from the values noted above; therefore, this analysis does not attempt to use them. As additional information becomes available, however, follow-on research could evaluate the impacts of different crediting values on the long-run evolution of the U.S. power sector.

Three separate CES cases are considered here:

- CES – High-EUR case
- CES – High-EUR case where CCS is not available, either for technical, economic, or social reasons
- CES – Low-EUR case.

Table 11 summarizes the three cases evaluated in the CES scenario.

Table 11. Description of CES Scenario

Case Name	Is Carbon Capture and Sequestration Available/Economic?	Assumption for Estimated Ultimate Recovery (EUR)
CES – High-EUR	Yes	High-level
CES – High-EUR, without CCS	No	Mid-level
CES – Low-EUR	Yes	Mid-level

[139] Three Senate leaders have put forth CES legislation since then: Senator Lindsay Graham (SC), Senator Dick Lugar (IN), and Senator Jeff Bingaman (NM).
[140] For more background on renewable portfolio standards and clean energy standards, see (C2ES 2012).
[141] On March 1, 2012, Senator Jeff Bingaman introduced the Clean Energy Standard Act of 2012. More information on the bill is available at: http://www.energy.senate.gov/public/index.cfm/democratic-news?ID=67e21415-e501-42c3-a1fb-c0768242a2aa.

Figure 31 presents the impacts of the three CES cases on generation through 2050. In the early years before 2030, natural gas replacing coal is the primary contributor to meeting the rising CES targets. Beginning around 2030, however, natural gas is no longer able to contribute to meeting the target without CCS because it receives only 50% crediting toward the target. Instead, coal with CCS, wind, and natural gas with CCS are the next-cheapest options in the CES – High-EUR case. If CCS is not available (CES – without CCS), wind generation is the next-cheapest alternative to take its place. In such a case, renewable energy sources contribute about 80% of total generation by 2050.[142]

A CES power future with more costly natural gas (CES – Low-EUR) would result in less natural gas generation, more solar and wind, and reliance on coal CCS rather than gas CCS compared to the CES – High-EUR case.

[142] NREL recently published the RE Futures study that evaluates many of the technical issues and challenges of operating the grid with such high percentages of renewable energy. See NREL (2012) for more detail.

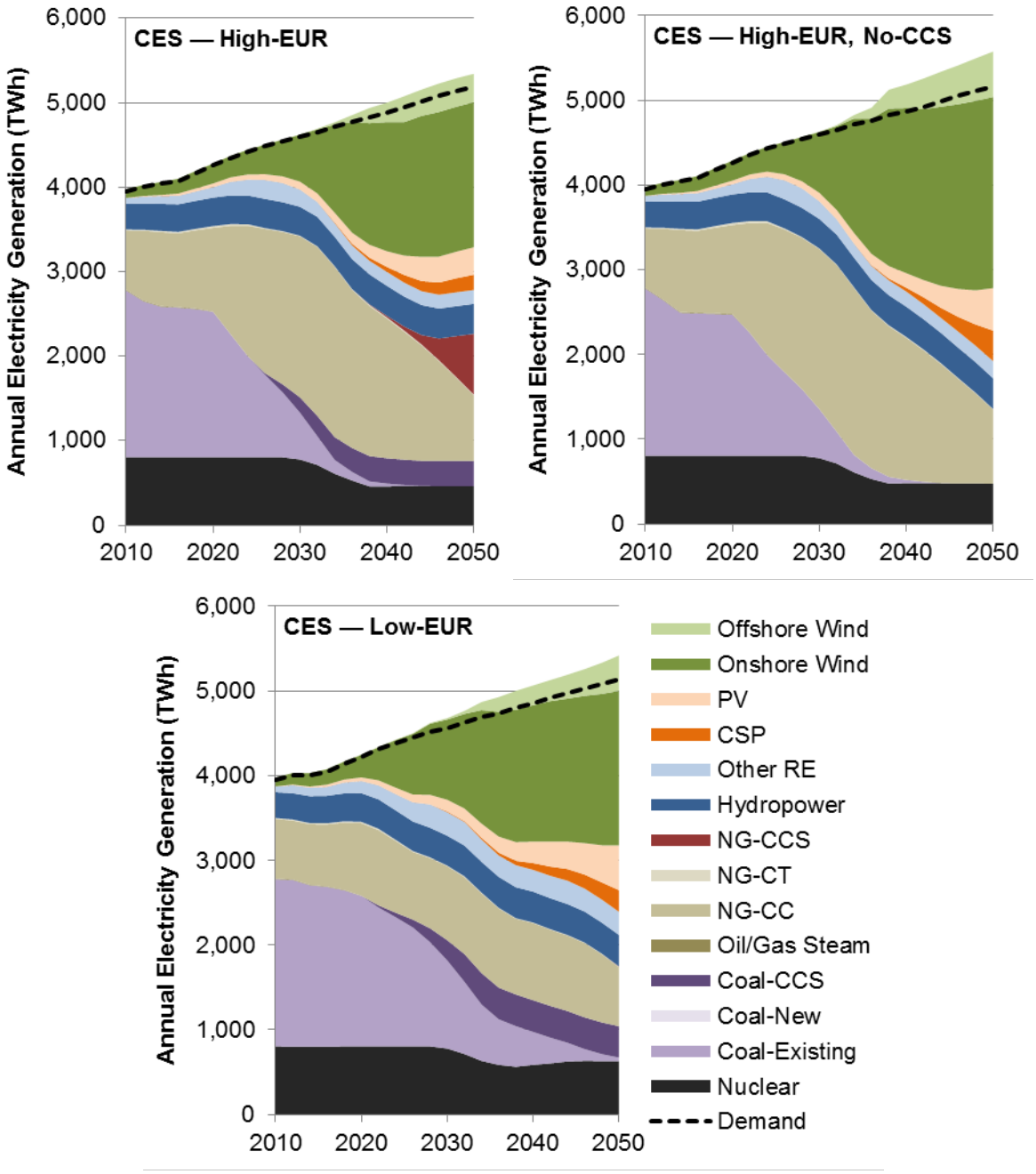


Figure 31. Projected generation in CES scenario, 2010–2050 for CES – High-EUR, CES – High-EUR, without CCS; and CES – Low-EUR cases

The amount of natural gas used in the CES scenario varies significantly by case, as shown in Figure 32. In all cases, however, it peaks around 2030, and prices remain lower than the Baseline – Mid-EUR case through 2050. Power sector gas demand temporarily falls after 2030 in the CES – High-EUR case, but begins to climb again around 2040 as natural gas CCS becomes an economic contributor to the CES target. When CCS is not available, natural gas consumption continues to decline and is back at 2010 levels by 2050. In the CES – Low-EUR case, natural gas usage remains muted throughout the scenario lifetime as other options meet the target more economically. Average real electricity prices would increase compared to the Baseline – Mid-EUR case beginning in roughly 2020 and settle at levels between 6% and 12% higher by 2050.

By 2050, CO_2 emissions from the U.S. power sector decline by more than 80% in all CES cases compared to the baseline. Coal generation without CCS has disappeared by that time in all cases. The power sector would be on a trajectory in all CES cases to achieve that sector's contribution to carbon mitigation commensurate with levels the Intergovernmental Panel on Climate Change deems necessary to stabilize atmospheric concentrations of greenhouse gases (IPCC 2007) at a level that could avoid the most dangerous aspects of climate change.

Because the CES cases project a very large build-out of wind power, ReEDS tracks the amount of new transmission lines needed to deliver power from where it is generated to where it is used. The estimated costs of building this new transmission infrastructure are included in the capacity analysis. Figure 33 presents a geospatial map of where new transmission lines would be required through 2050. The vast majority of this new wind generation would be constructed in the Midwestern states for use throughout the Eastern Interconnect. Smaller quantities would be built in the Western and Electric Reliability Council of Texas (ERCOT) Interconnects. The greatest amount of transmission is needed when CCS is not available, and wind must play an even larger role. In this case, more than twice the amount of transmission, as measured in million megawatt-miles of capacity, would be needed compared to the CES – High-EUR case in 2050 (or six-times the amount as the Baseline – Mid-EUR case).

4.5.1 Implications of CES Scenario

The CES options analyzed here indicate that the U.S. power sector could achieve significant decarbonization by 2050 at relatively modest economic costs, although barriers to building sufficient transmission may be formidable (NREL 2012). About six times more transmission is needed in the CES – without CCS case than in the Baseline – Mid-EUR case by 2050, and three times as much in the CES – High-EUR case. A greater diversity of power generation is achieved when CCS is available and economic for use on coal or gas plants. Heavy reliance on the need for transmission is also lessened when CCS is available. Additional research should be considered to evaluate potential natural gas infrastructure barriers in such a scenario of high variable renewable energy generation.

In all CES cases, large quantities of variable renewable energy are supported and firmed by flexible natural gas generators. Natural gas generators help enable a power generation mix that relies heavily on variable renewable technologies such as wind and solar.

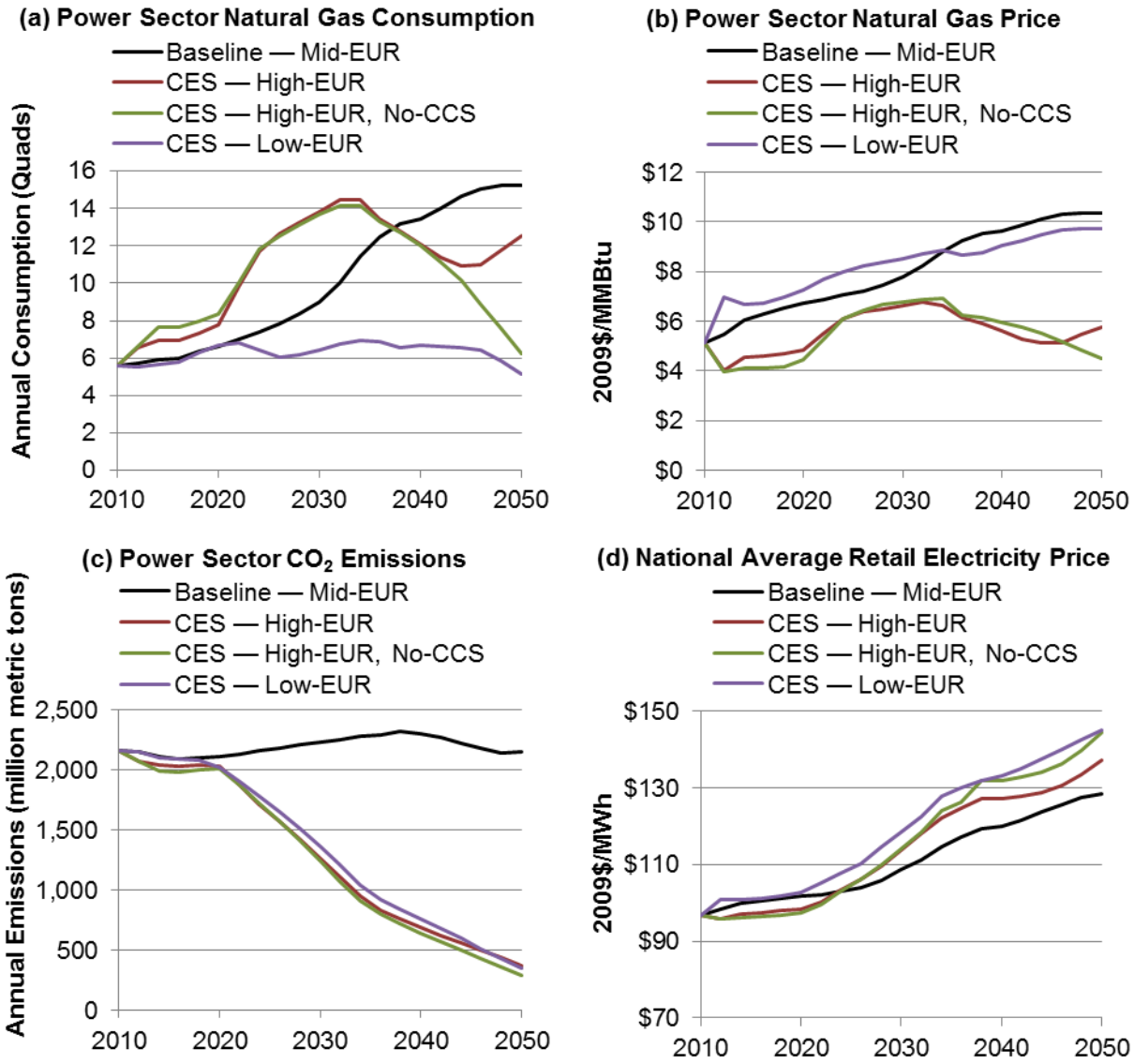
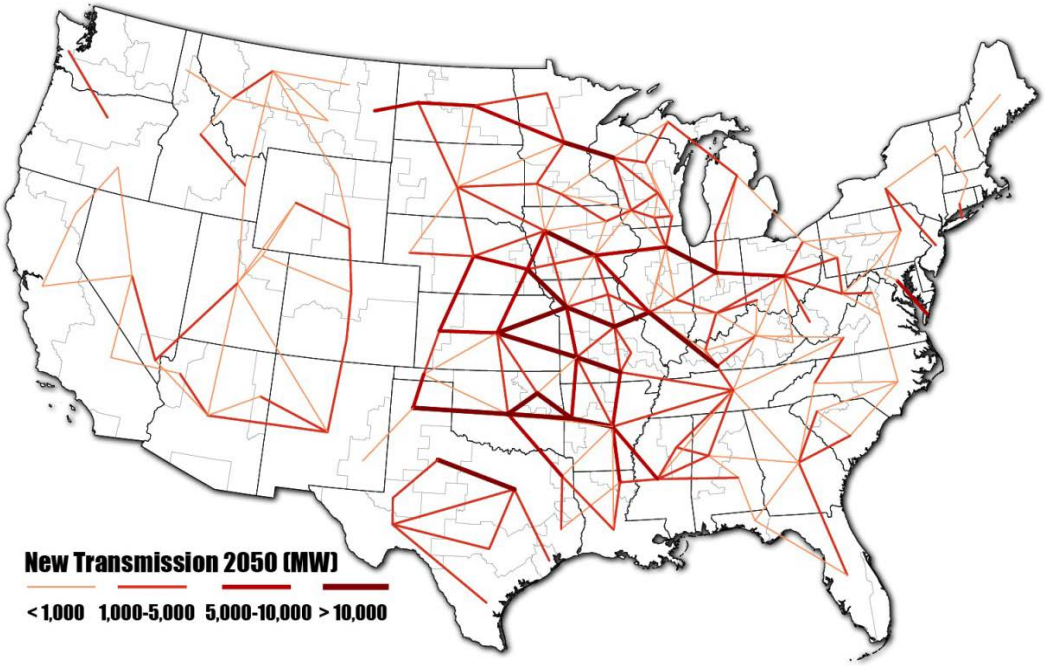


Figure 32. Selected metrics for the CES scenario, 2010–2050



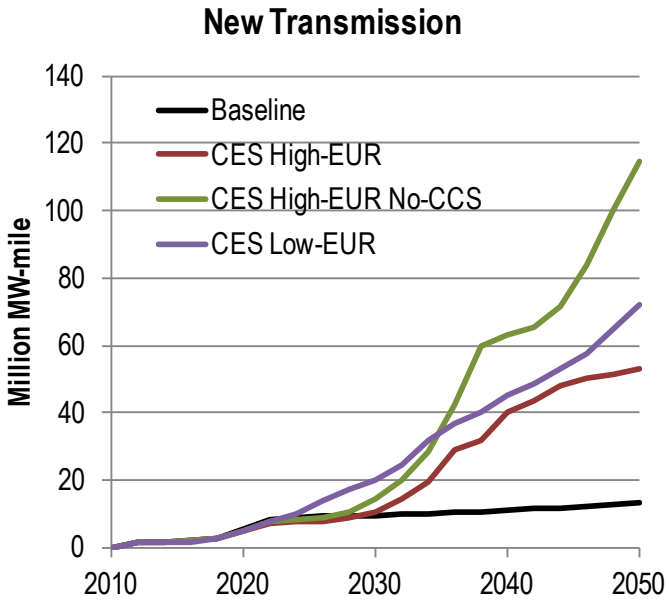


Figure 33. Map of new transmission required by 2050 in the CES – High-EUR case, and measures of new transmission needed in all cases, 2010–2050

4.6 Advanced Technology Scenario

The Advanced Technology scenario considers additional progress in the evolution of cost and performance metrics of certain generation options compared to the Baseline – Mid-EUR case. Two cases are considered here:

- *Advanced Nuclear:* A 50% reduction in the capital costs of nuclear generation by 2020. This scenario also uses a Low-EUR assumption for natural gas.
- *Advanced Renewable Electricity (RE):*[143] Capital costs for utility-scale solar PV, concentrating solar power (CSP) with thermal storage, and wind are assumed to decline, as shown in Table 12. In addition, improvements in performance of advanced RE technologies are assumed to be more significant, as shown in Table 13 (e.g., in 2050, Class 5 wind is assumed to have an annual capacity factor of 46% compared with 43% in the baseline). CSP is assumed to have the same performance as in the baseline, but with towers available at an earlier time (2015 instead of 2025), resulting in higher performance earlier. Furthermore, distributed PV was exogenously input and assumed to reach 240 GW of capacity by 2050,[144] compared to 85 GW in the baseline. This case uses a Mid-EUR natural gas assumption.

Table 12. Assumed Reductions in Capital Costs for the Advanced Technology Scenario

	2020 ($/kW)	2050 ($/kW)
Advanced Nuclear	6,200 → 3,100	6,200 → 3,100
Advanced On-shore Wind	2,012 → 1,964	2,012 → 1,805
Advanced PV	2,550 → 2,213	2,058 → 1,854
Advanced CSP	6,638 → 4,077	4,778 → 2,982

Table 13. Assumed On-shore Wind Improvements in Capacity Factors for the Advanced Technology Scenario

	Class 3	Class 4	Class 5	Class 6	Class 7
2020	0.33 → 0.38	0.37 → 0.42	0.42 → 0.45	0.44 → 0.48	0.46 → 0.52
2050	0.35 → 0.38	0.38 → 0.43	0.43 → 0.46	0.45 → 0.49	0.46 → 0.53

Table 14 summarizes the major assumptions used in the Advanced Technology scenario.

[143] Advanced RE capital costs and performance improvements were taken from the RE Futures report (NREL 2012), evolutionary technology improvement (RE-ITI) cost projection.
[144] This projection is based on the SunShot Vision Report (DOE 2012).

Table 14. Description of Advanced Technology Scenario

Case Name	Cost Assumption	Assumption for Estimated Ultimate Recovery (EUR)
Advanced Nuclear	Nuclear capital costs decline by 50% in 2020 compared to the baseline scenario.	Low-level
Advanced RE	Wind, PV, and CSP capital costs decline as shown in Table 12. Performance improvements as described above and shown in Appendix E.	Mid-level

The impact of potential improvements in these two categories of technology is shown in Figure 34. The primary impact in the Advanced Nuclear case is that enough new nuclear generation is built to offset the decline in age-based retirements by the end of the modeling period.[145] Additionally, because this case assumes a Low-EUR for natural gas (and thus, higher prices), some new coal plants are also built beginning in 2030 to meet load. The new coal plants largely offset the carbon abatement that otherwise would have occurred due to the new nuclear generation. Retail prices are also higher during most of the reporting period because the Low-EUR assumption was made (see Figure 35).

In the Advanced RE case, wind and solar generation expands considerably compared to the Reference scenario. In the case of wind, this illustrates the sensitivity of potential expansion because the assumed cost reductions and performance improvements were relatively modest. Growth in utility-scale PV capacity is substantial in this case, while actual generation increases more modestly due to the relatively low capacity factor that solar achieves. By 2050, CO_2 emissions decline by a little more than one-quarter compared to the baseline, while retail electricity prices are also slightly lower due to the assumed reduction in cost for RE technologies (Figure 35).

4.6.1 Implications of the Advanced Technology Scenario Findings

Under the assumptions used in this analysis, nuclear generation does not become cost competitive with other options until capital costs decline by roughly one-half from today's level and natural gas prices are assumed to be relatively high (Low-EUR). Even under the cost assumptions used in the Advanced Nuclear case, new coal was still competitive with the cheaper nuclear, offsetting some of the carbon advantages of nuclear. Despite these apparently high hurdles, breakthroughs in advanced nuclear designs are possible (OECD 2011; Martin 2012) and could contribute meaningfully to a more diverse and energy-secure power future in the United States.

Even modest reductions in capital costs for renewable energy technologies can have significant impact on their competitiveness compared to baseline assumptions. Wind power appears particularly sensitive to assumed reductions in capital cost and performance improvements, expanding nearly 100% compared to the baseline with capital cost reductions of about 10%. Similar reductions in utility PV capital costs lead to near-identical impacts in the deployment of that technology, whereas a greater reduction in CSP capital costs would be needed to see a large expansion in the role of that technology.

[145] This case was also evaluated under High-EUR and Mid-EUR gas futures, but nuclear was not competitive in that environment, so only the Low-EUR results are shown here.

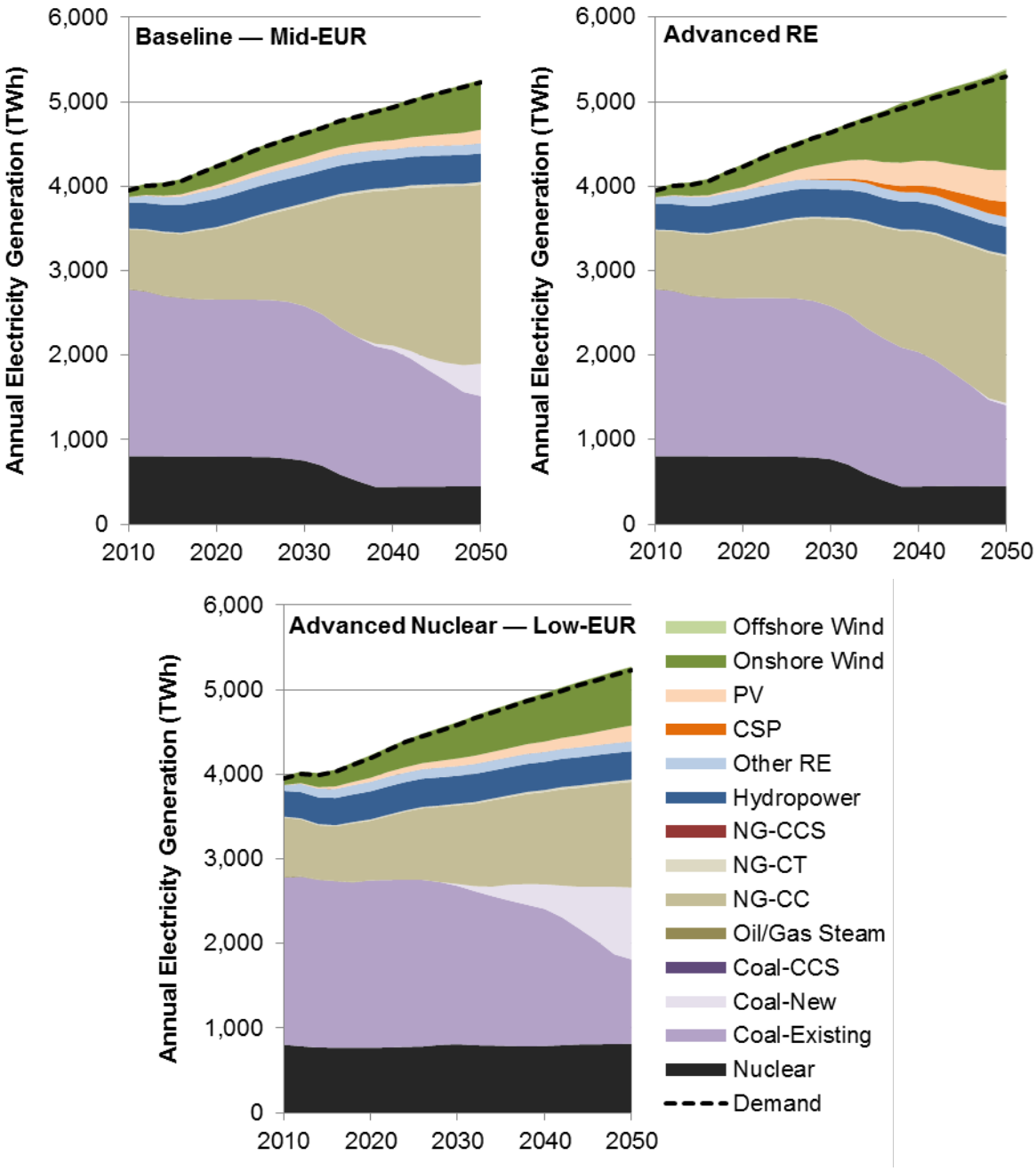


Figure 34. Generation in the Advanced Technology scenario, 2010–2050

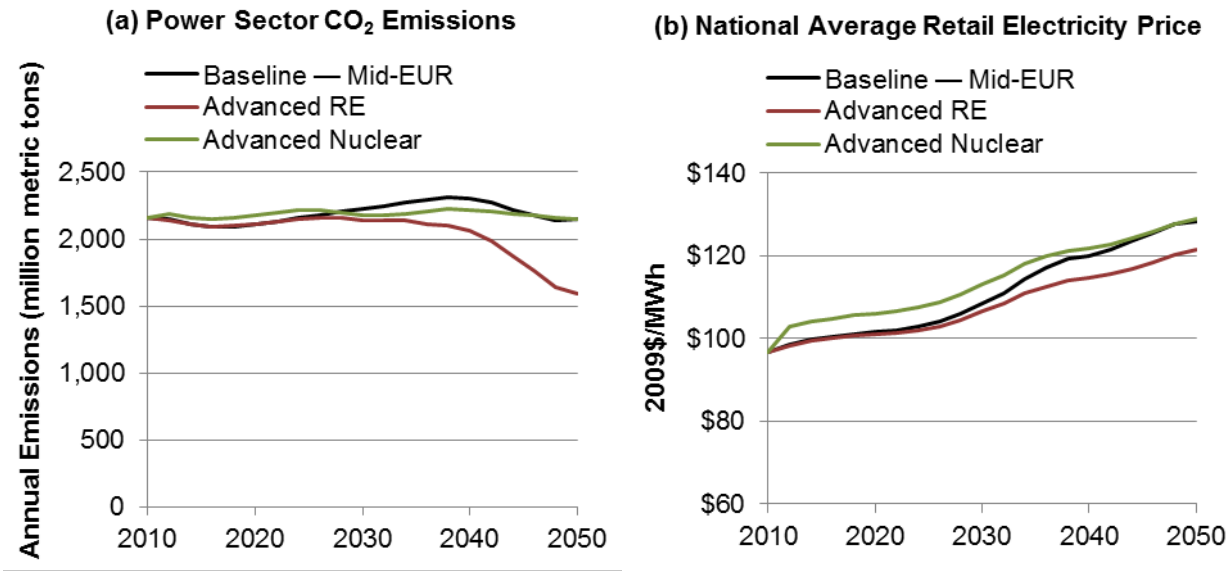


Figure 35. Selected metrics for the Advanced Technology scenario, 2010–2050

4.7 Natural Gas Supply and Demand Variations Scenario

Two separate cases are considered here:

- *Natural Gas Supply Cost Variations:* Variations in natural gas supply costs that could result either from additional state or federal regulations, or from more costly field practices that suppliers follow to better protect the environment. The impact of these incremental natural gas costs on the power sector over the longer-term are simulated using ReEDS. This analysis covers a broad range of potential incremental costs associated with producing natural gas in a way that commands stronger public support yet is still feasible for producers and consumers. Chapters 2 and 3 of this study discuss practices that could result in this more secure outcome on the supply side, but does not arrive at actual estimates of incremental cost impacts in $/MMBtu terms. The values used here could still be helpful to those who know what their incremental costs are, or to a broader audience in the future when cost estimates are available.
- *Natural Gas Demand Variations:* Variations in demand for natural gas outside the power sector that could result from a "dash-to-gas" across the larger economy. This dash-to-gas could occur in the export of LNG, greater use of natural gas in vehicles (either as compressed natural gas throughout the fleet, or as LNG in heavy-duty vehicles). Under a dash-to-gas case, natural gas prices rise due to the greater demand and make it more expensive for power generators to use natural gas generation.

Table 15 summarizes key assumptions used in the Supply and Demand Variations scenario.

Table 15. Description of Natural Gas Supply and Demand Variations Scenario

Case Name	Focus	Assumption for Estimated Ultimate Recovery
Natural Gas Supply Cost Variations	Evaluate impact to power sector as incremental natural gas production costs increase from $0.50/MMBtu to $2/MMBtu	Mid-level
Natural Gas Demand Variations (Dash-to-Gas)	Evaluate impact to power sector as natural gas demand in other sectors increases by 12 bcf/d by 2026	High-level

4.7.1 Natural Gas Supply Cost Variations

Figure 36 illustrates adjustments to the natural gas supply curves that could result when additional measures are taken to protect the environment when producing natural gas. These measures could be the result of new regulations or different practices in the field. Examples of these added costs might include the following:

- Activities such as recycling or treating a greater quantity of water supply used in hydraulic fracturing
- Minimizing the amount of methane that is released to the atmosphere before, during, and after fracturing a well
- Casing wells in a more robust and consistent way
- Practicing more robust techniques of cement bond logging
- Substituting more environmentally benign options for traditional hydraulic fracturing additives
- Engaging local stakeholders in dialogues in advance of drilling to ensure their concerns are heard and addressed
- Enforcing larger setbacks from potentially sensitive communities
- Disposing of or treating flowback water in improved ways.

Few publicly available studies estimate what these specific costs might be and how they vary by region. The International Energy Agency (IEA) recently published Golden Rules for a Golden Age of Natural Gas (IEA 2012), a very general statement of 22 steps that should be considered when producing natural gas. The IEA report stated that, "We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%."[sic] (IEA 2012). Therefore, if it normally costs $3.00/MMBtu to develop shale gas, the Golden Rules cost would be $0.21/MMBtu higher at a typical play. This is nominally consistent with, although lower than, recent estimates of the costs of complying with pending federal rules—including the new EPA air regulations for oil and gas producers, which might cost between $0.32 and $0.78/MMBtu, according to one analyst (Book 2012). Informal consultations associated with this study suggest that maximizing water recycling might result in $0.25/MMBtu in added costs. The additional costs that could result from enhanced environmental and safety practices in the field, noted in Chapters 2 and 3, were unable to be quantified. However, it is clear that these costs will vary by region and that many additional safeguards could be practiced at less than an incremental cost of $1/MMBtu. A 2009 study funded by the American Petroleum

Institute anticipated much higher costs if new federal regulations were imposed on natural gas producers (IHS 2009).

To assess the potential impacts of these incremental supply costs, this study considers a range of additional costs—starting from $0.50/MMBtu and going up to $2/MMBtu in increments of $0.50/MMBtu—and evaluates the impacts on the long-range evolution of the power sector when these costs are applied. Figure 36 shows the reduction in natural gas use in the power sector as incremental costs are increasingly applied. At the upper limit, natural gas consumption for power generation declines from roughly 15 quads[146] in the Baseline – Mid-EUR case to 10 quads (incremental $2/MMBtu added) by 2050. With a $0.50/MMBtu added cost of gas production, the long-term impacts are far more modest—resulting in a reduction of gas use for power generation in 2050 of less than 2 quads. Coal—and wind, to a lesser extent—replaces the generation lost by the more expensive gas. Other impacts associated with these assumed incremental costs appear relatively modest.

[146] To roughly convert from quads to bcf/d, multiply by 2.6. Thus, 15 quads per year equal about 38.5 bcf/d.

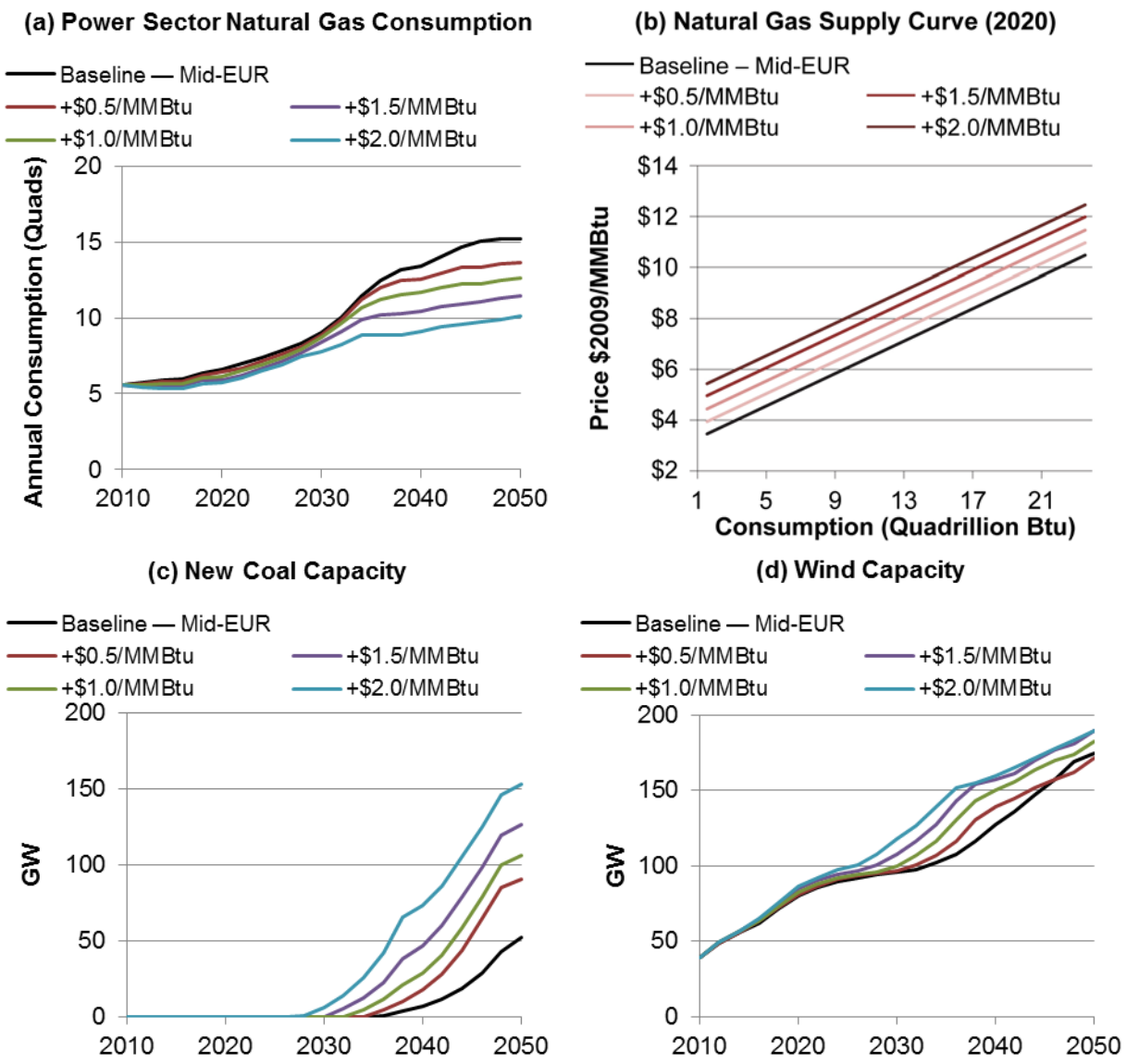


Figure 36. Selected metrics for the Natural Gas Supply Cost Variation case, 2010–2050

4.7.2 Natural Gas Demand Variations (Dash-to-Gas)

The Natural Gas Demand Variations case considers the impact to potential expansion of natural gas generation if a significant shift to natural gas occurs in other sectors of the economy. Specifically, it looks at the combined potential of new LNG exports, natural gas vehicle deployment (both compressed natural gas and LNG in heavy-duty trucking), and use in industrial and chemical applications and any other sector that in aggregate reaches 12 bcf/d by 2026.

A growing number of studies analyze the impact of LNG exports on domestic natural gas prices (EIA 2012b; Pickering 2010; Deloitte 2011; Ebinger et al. 2012). Estimates vary considerably depending on methodology used, location, and assumptions about overall gas availability. The case examined here uses the methodology in the EIA LNG exports scenario as a basis for the full

economy "dash-to-gas."[147] Thus, it takes the "high and slow" EIA-derived price impact of exporting 12 bcf/d of LNG by 2026 and uses it to represent the impact of a combined 12 bcf/d in the total economy, distributed among LNG exports, vehicle use, industrial use, and any other applications (see Figure 37 and Table 16).

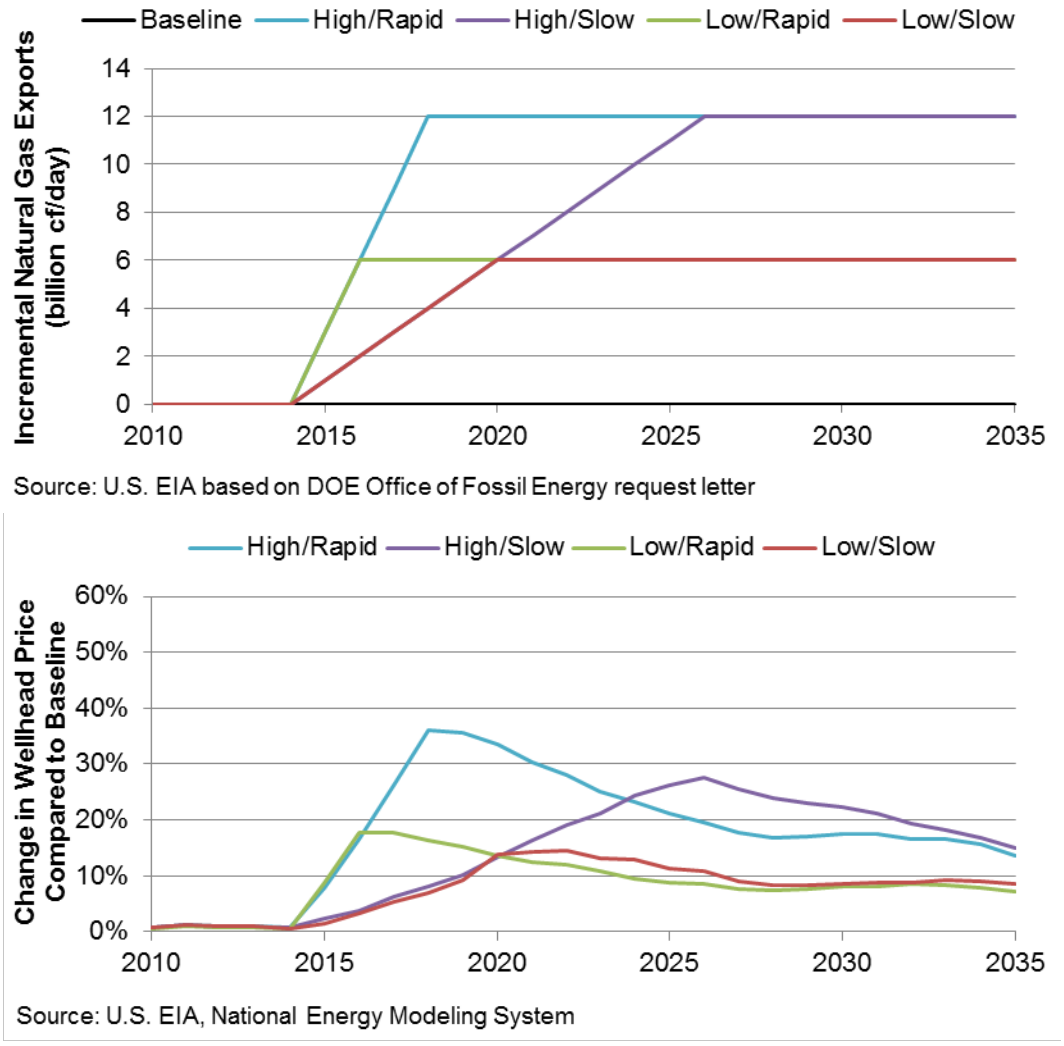


Figure 37. EIA LNG export scenarios and their projected impacts on domestic natural gas prices, 2010–2035

[147] The upper limits (i.e., high/rapid scenario) of the EIA study have been criticized by some (Ebinger et al. 2012) as too extreme and not representative of how LNG exports might really occur. Although the study in this report uses the second-most extreme (high/slow) LNG export scenario considered by the EIA, the scenario is constructed to capture a wider range of potential natural gas end-uses than just LNG exports.

Table 16. Non-Power Sector Natural Gas Demand Assumptions in the Natural Gas Demand Variations Case

	2010	2020	2030	2040	2050
	(billions of cubic feet per day)				
LNG Exports	0	5.0	7.3	5.0	0
Vehicles[148]	0	1.5	2.7	3.0	0
Industry/Other	0	1.5	2.0	1.5	0
Subtotal	0	8.0	12.0	9.5	0

In the Natural Gas Demand Variations (dash-to-gas) case, gas prices rise by a maximum of 29% above the Reference scenario value in 2026 before re-equilibrating. The power sector mix is similar to the Baseline – Low-EUR case (compare Figure 38 with Figure 26), although still slightly more reliant on natural gas generation. A dash-to-gas future, then, would restrict gas generation to less than doubling by 2050 compared to the 2010 level. The larger macroeconomic impacts associated with this future were not evaluated; however, overall gas demand declines by about 3 quads by 2050 (Figure 39) compared to the baseline. The price of natural gas for power generators rises by a maximum of $2/MMBtu above the baseline value in the early 2020s before returning to the baseline level in 2050, when the other sectors are assumed to terminate their extra reliance on natural gas (see Figure 39).

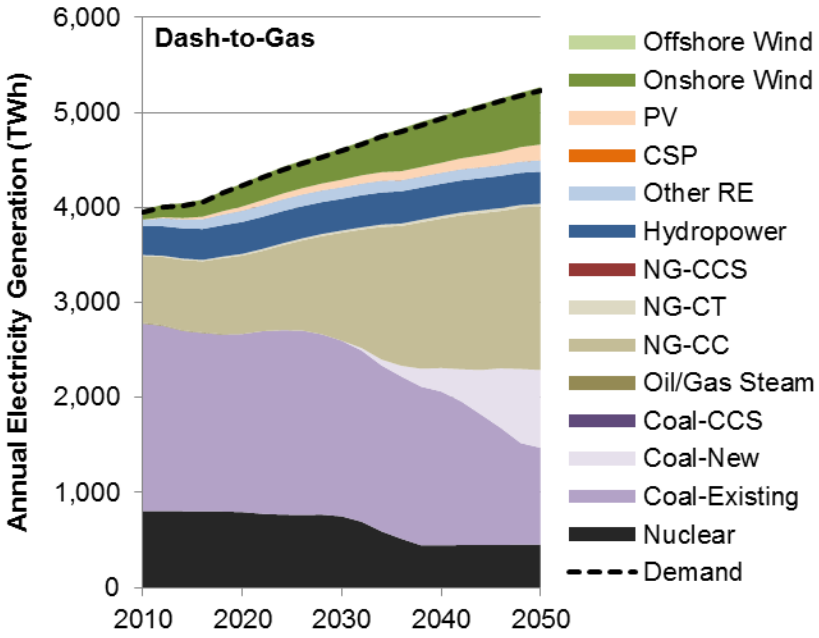


Figure 38. Power generation mix in the Dash-to-Gas case

[148] These estimates for compressed natural gas use in vehicles are proposed by Wellkamp and Weiss (2010).

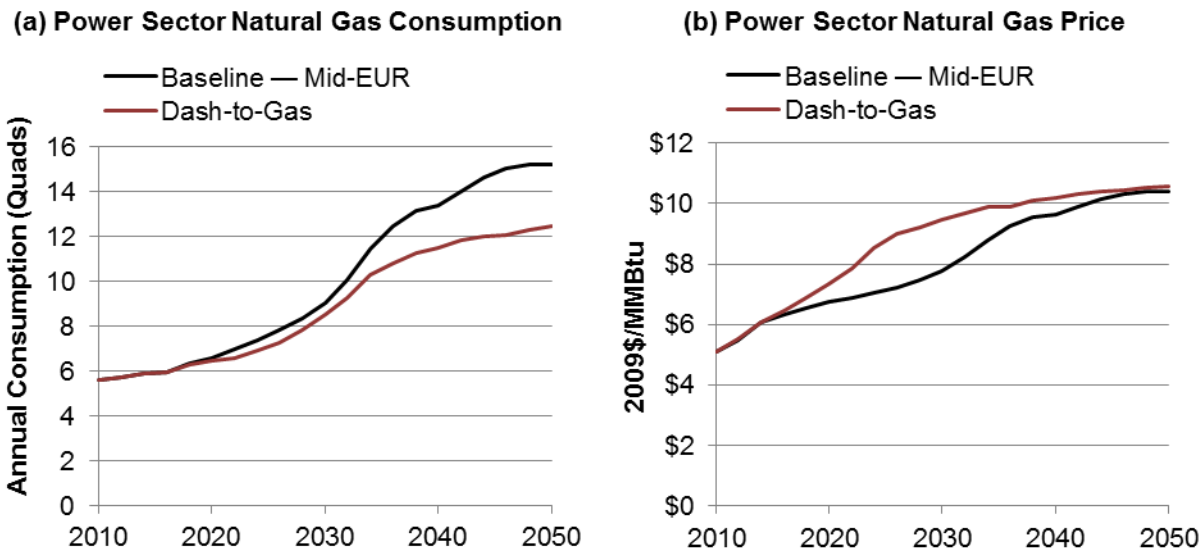


Figure 39. Selected metrics for the Dash-to-Gas case, 2010–2050

4.7.3 Implications of the Natural Gas Supply and Demand Variations Findings

Many additional measures could be taken by producers to address the real and perceived risks associated with unconventional natural gas production at a modest impact to the evolution of the power sector. If total costs from a long list of potential practices reached $1.00/MMBtu, natural gas usage in the 2050 power sector might be expected to decline from 2.5 times the 2010 level in the Baseline to 2 times in the Supply Variation case. Costs associated with ensuring stronger public support of unconventional gas and oil production would vary by region and producer. Technologies associated with unconventional natural gas production are under rapid development, so the cost impacts will be changing dynamically. Follow-on research should attempt to gather additional data from producers to better estimate what the real cost would be of addressing issues of social license to operate on a basin-by-basin level. The question for industry might then be: Are these added costs worth absorbing—and an acceptable price to pay—to ensure both greater public and utility-sector confidence in the production practice over the longer term?

Understanding the price impacts of a Dash-to-Gas case is still poorly characterized due to the newness of the recent change in natural gas supply outlook. Based on currently available estimates, a fairly strong dash-to-gas in other sectors of the economy would have a visible, although still marginal, impact on the evolution of the electric power sector—with natural gas use declining somewhat due to the higher prices and other forms of generation increasing to take its place. As additional experience and estimates of this elasticity become available, follow-on research should re-examine the impacts.

4.8 Conclusions for Power Sector Modeling

The role of natural gas in the U.S. power sector is sensitive to assumptions about EUR. More research is needed to better understand how much gas will ultimately be recovered from unconventional plays.

Coal retirements and fuel switching are already occurring ahead of the rollout of EPA rules. The modeling results indicate that any new plants needed to replace retiring coal would mostly be fired by natural gas and that on an aggregate level, reliability standards are maintained without an unusual level of new construction. This analysis did not attempt to evaluate location-specific reliability impacts associated with coal-plant retirements; more granular dispatch models would be needed to investigate those questions with more certainty.

The CES modeling results indicate that substantial reductions in CO_2 emissions are achievable at modest cost, although transmission barriers could stand in the way. When CCS is not available under a CES, generation options decline, the need for new transmission expands significantly, and the power mix becomes less diverse. Therefore, CCS is an important option for a low-carbon power sector, but may not be essential.

Continued focus on technology research, development, and deployment is needed to bring down costs and ensure a diverse power mix in the future. Even modest reductions in renewable energy capital costs and improvements in performance may have a meaningful impact on their continued deployment in the future. Continued advancements in technologies used to find and produce unconventional gas could also have a strong impact on improving the social license to operate at an acceptable price, and thus, should be pursued at all levels.

Finally, increased costs associated with potential changes in field practices of natural gas producers were evaluated over a fairly broad range. If these costs turn out to be less than an incremental $1/MMBtu, then the long-term impact on natural gas in the power sector is not significantly different from the baseline conclusions: gas demand for power generation declines by about 17% while CO_2 emissions increase marginally. An important outcome of this study—and a potential question for follow-on research and discussion—would be whether these additional costs associated with protecting the environment, improving safety, and commanding public confidence are worthwhile to society and gas producers.

Natural gas appears plentiful and at historically low price levels for the foreseeable future, but going forward, decision makers may want to pay special attention to generation diversity. An undesirable outcome would result if a major shift to natural gas generation occurred before a substantial rise in natural gas prices—due, for example, to mischaracterizations of EUR, a failure to earn the social license to operate, or some other reason that may currently be considered "unlikely." Continuing research, development, and deployment over a wide variety of generation and gas production options can help prevent such an outcome. It would also provide greater flexibility in addressing the threat of climate change.

5 Conclusions and Follow-On Research Priorities

5.1 Conclusions

Major, high-level findings derived from the research conducted in this study include:

- Life cycle greenhouse gas emissions associated with electricity generated from the Barnett Shale play gas in 2009 were found to be very similar to conventional natural gas and less than half of those associated with coal-fired power generation.
- Low-priced natural gas has led to more than 300 terawatt-hours of fuel switching from coal to gas in the U.S. power sector between 2008 and 2012. This switching, in combination with rapid growth in certain renewable energy generation sources, has led to a reduction in power-sector carbon dioxide emissions of about 300 million tons—about 13% of the sector's total. This fuel switching may stop or reverse itself if natural gas prices rise relative to coal. Natural gas can play an important role in greenhouse gas mitigation over the short- to mid-term, but if policymakers pursue an 80% mitigation target by 2050, carbon capture and sequestration may need to be commercially viable by 2030 for natural gas power generation to continue growing.
- The legal and regulatory frameworks governing shale gas development are changing in response to public concerns, particularly in regions that have less experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with greater unconventional natural gas production. Better coordination and information sharing among regulators may help ensure efficient and safe production, while greater availability of transparent and objective data may help address some of the public's concerns.
- States and natural gas producers are developing additional, often voluntary, field practices to ensure that shale gas can be produced with high standards of environmental protection—although these standards are not always uniformly followed. Continued advances in technologies and practices could help address public concern over unconventional gas production. Some data, such as the amount of water used per well in hydraulic fracturing, are readily available and can be analyzed on a regional basis. However, a lack of publicly available information on industry practices limits a full-scale assessment of water risks associated with shale gas operations. Further collaboration and interaction with industry partners could help improve data collection efforts.
- A suite of different future electric power scenarios was evaluated to test the implications of different policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gases, and variations in natural gas supply and demand. The study found that natural gas use grows robustly in nearly all scenarios over the next two decades. Over the longer term, natural gas demand for electricity generation faces greater uncertainty, leading to larger ranges of change in gas demand—including the case where demand in 2050 is roughly the same as that in 2010 in the event a clean energy standard is pursued and carbon capture and sequestration is not commercially available (see Figure 32).

Readers should consult corresponding chapters to view more comprehensive findings and ensure that the appropriate context is conveyed with each finding.

5.2 Follow-on Research

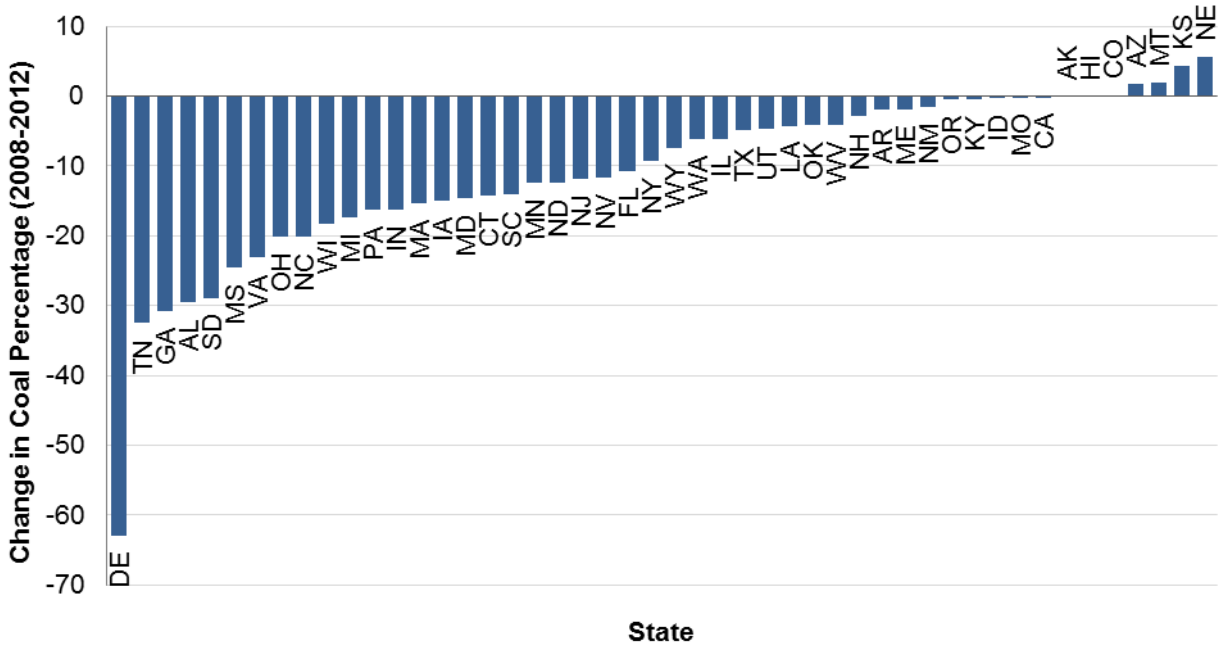
Because of time and budget constraints, the research team could not investigate some issues as fully as warranted. Each chapter identifies areas where additional research would likely lead to improved understanding on certain issues. Selected follow-on research taken from this larger list is presented below. Please refer to the main chapters for a more comprehensive discussion on these follow-on research topics.

- More field-measurement-based research on methane leakage and mitigation options at unconventional gas production facilities (outside of the Barnett Shale play) considering geographic and operational variability at well, play, and national scales.
- More industry- and basin-specific research to estimate the incremental costs associated with various regulatory scenarios, including more robust environmental standards in unconventional gas production. Additional social research to understand how improved standards might impact public perception of gas production and the social license to operate. Additional economic research to understand how higher costs would impact producers, and the degree to which they might be able to pass costs on directly to consumers.
- More comprehensive evaluation of risks in shale gas production and how they can be best addressed using new technologies and field practices. Increased quantitative understanding of the magnitude and probability of risks to water resources that result from current industry practices and proposed best management practices. More comprehensive evaluation of the regional diversity of risks, costs, and effective industry practices inherent in shale gas development.
- Greater understanding of the impact of additional natural gas demand, especially liquefied natural gas exports, on domestic and international prices. In general, greater certainty and understanding of natural gas price volatility and estimated ultimate recovery in the relatively new abundant natural gas environment would also be beneficial.
- Finally, this study did not use a modeling tool that simulated operation and expansion of natural gas pipelines. Follow-on work that included such capabilities might identify additional opportunities and barriers to growth in electric power natural gas use.

Appendix A: Shifting Coal Generation in U.S. States

This appendix summarizes recent data on changes in coal-fired electricity generation published by the Energy Information Administration (EIA) of the U.S. Department of Energy. Many of these changes are due to some combination of low-priced natural gas, aging coal generators, and impending regulations from EPA. However, some changes—especially in small states—could be unrelated. Using data at the state level—rather than the larger boundaries of regional transmission organizations or independent system operators—is somewhat artificial when showing changes in electricity generation. Nevertheless, state-level data are convenient, and important trends can be seen in the grouping of some states.

Figure 41 presents a snapshot of the change in coal-fired generation percentage between 2008 and the first 2 months of 2012 for most states. The charts that follow provide additional information on how changes in generation mix have occurred in the first 15 states shown in Figure 41.



Data: U.S. Energy Information Administration, Electric Power Monthly, data through February 2012.
Note: DC, RI, and VT are not included.

Figure 41. Changes in coal percentage of total net generation at the state level, 2008–2012

Figure 42 through Figure 56 show how generation mix has changed between 2005 and early 2012 for the 15 states with the largest drop in coal percentage as a percent of total net generation. The data for all of these figures come from the U.S. Energy Information Administration, "Electric Power Monthly." The data are through February 2012, and the 2012 data include only January and February net generation. Some seasonal effect is reflected in the 2012 year-to-date data points.

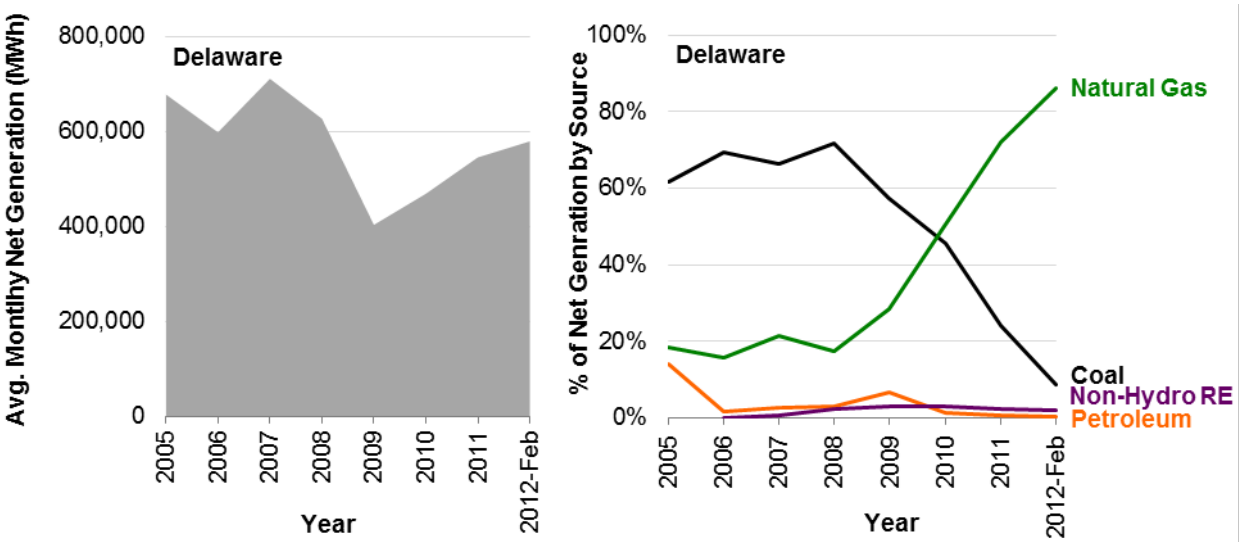


Figure 42. Changes in generation mix in Delaware; 2005–early 2012

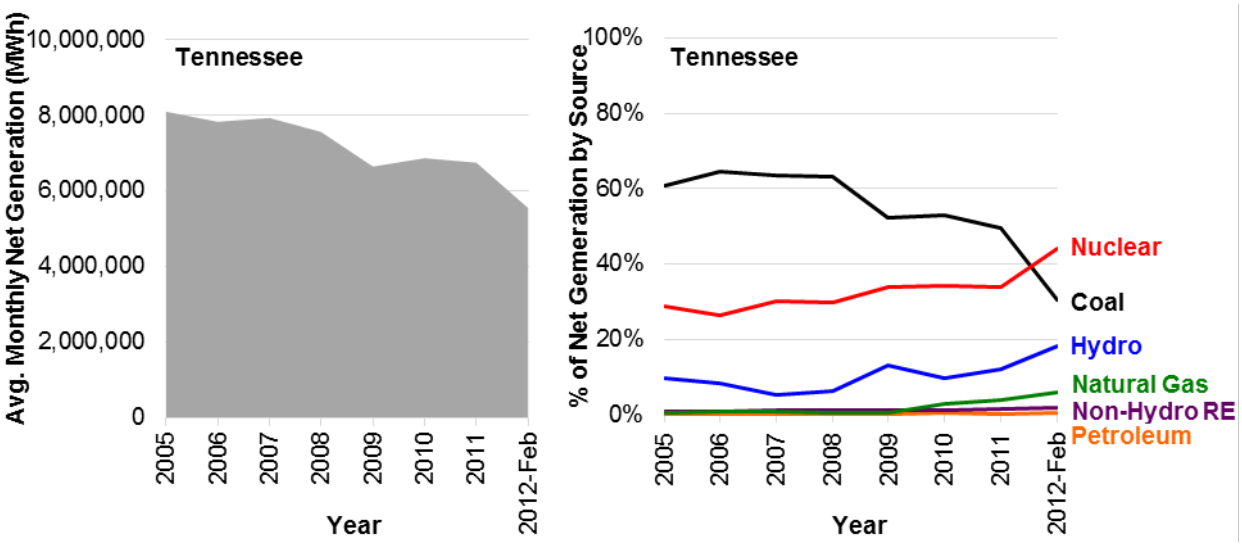


Figure 43. Changes in generation mix in Tennessee; 2005–early 2012

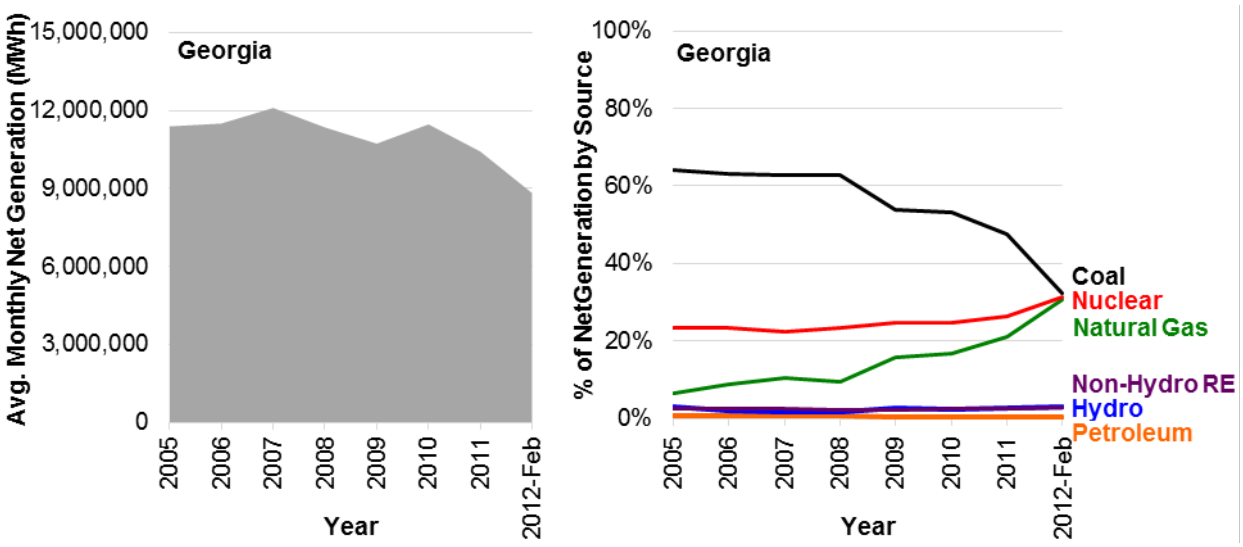


Figure 44. Changes in generation mix in Georgia; 2005–early 2012

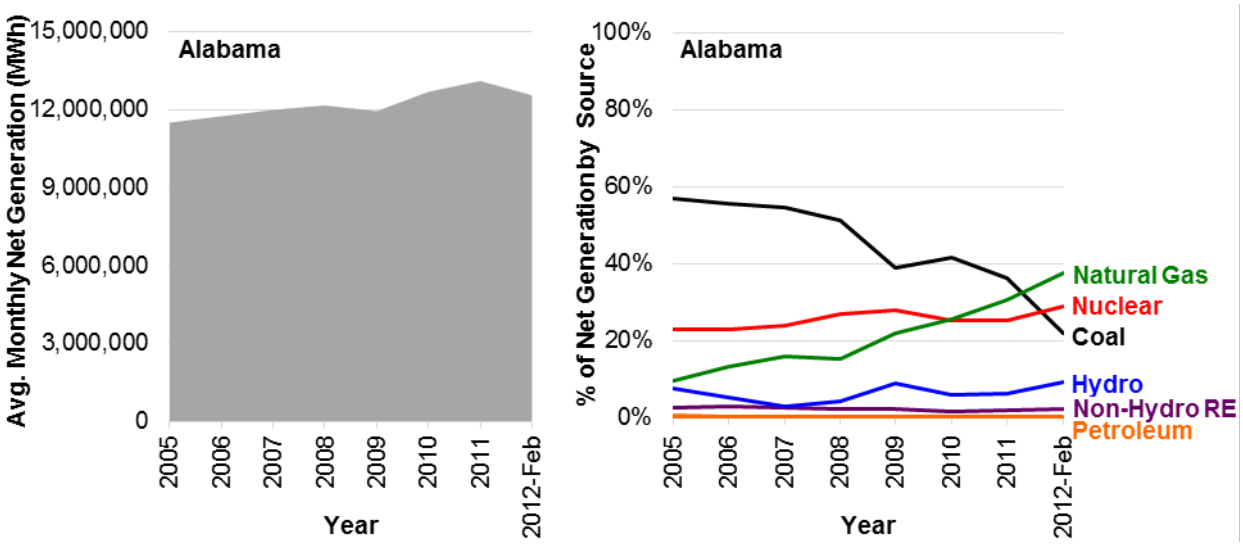


Figure 45. Changes in generation mix in Alabama; 2005–early 2012

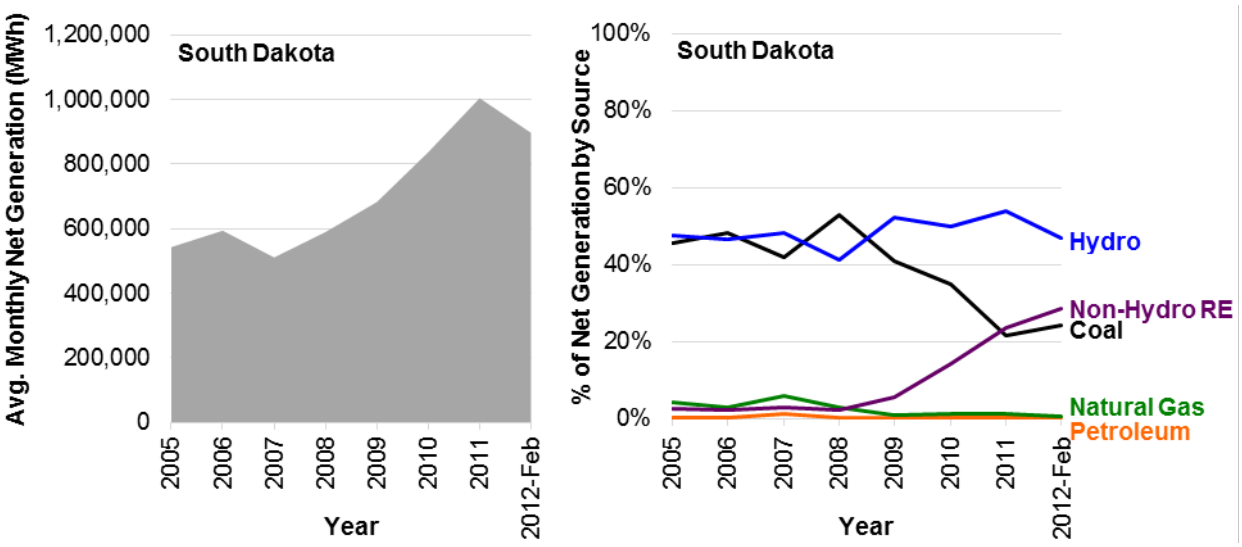


Figure 46. Changes in generation mix in South Dakota; 2005–early 2012

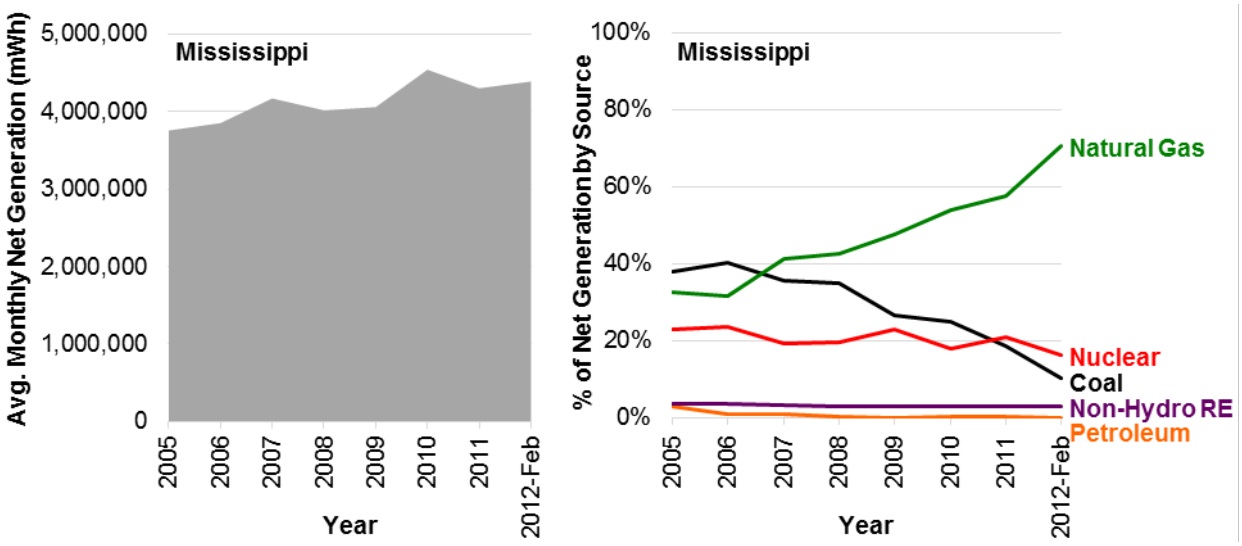


Figure 47. Changes in generation mix in Mississippi; 2005–early 2012

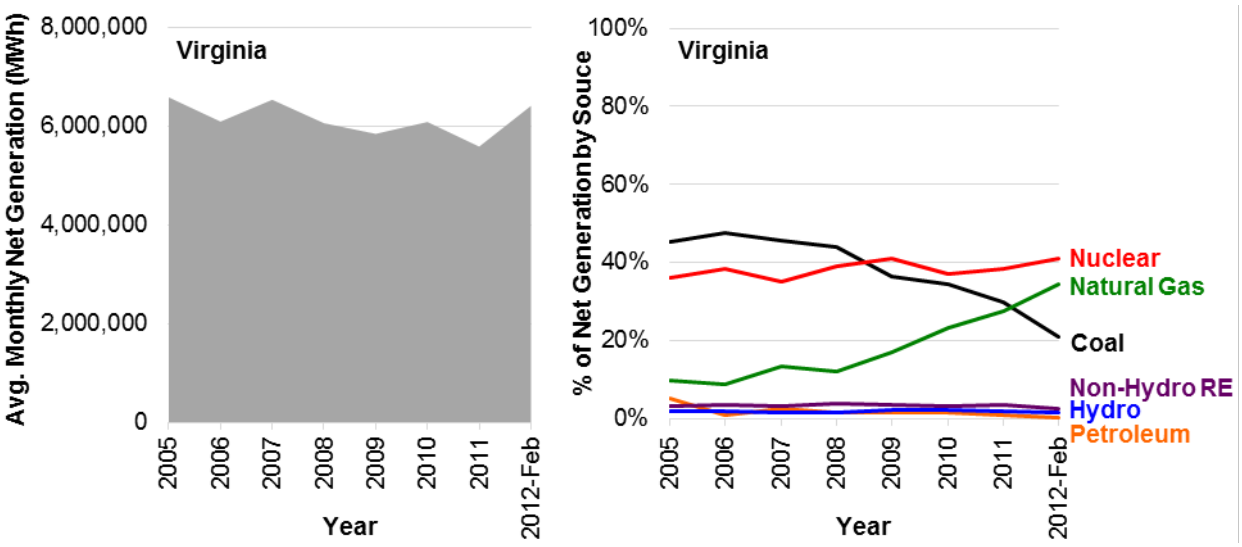


Figure 48. Changes in generation mix in Virginia; 2005–early 2012

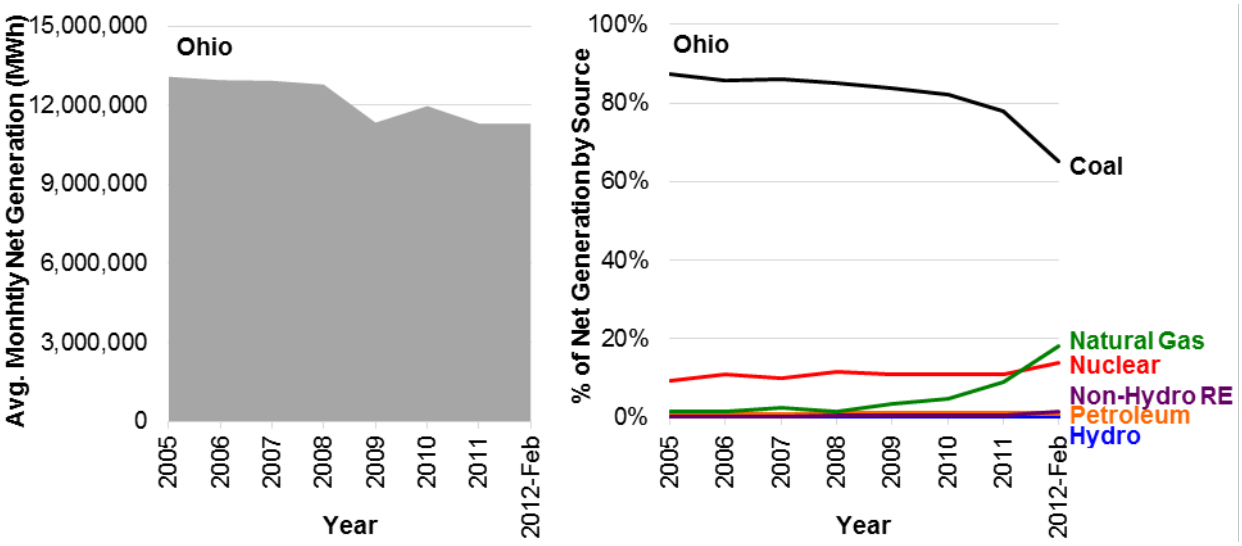


Figure 49. Changes in generation mix in Ohio; 2005–early 2012

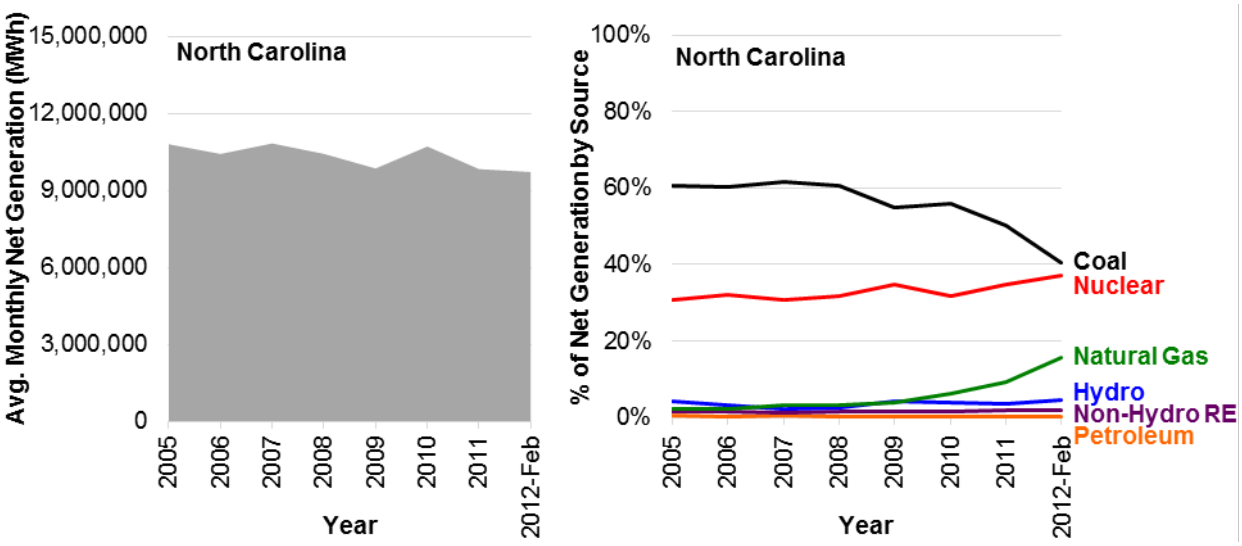


Figure 50. Changes in generation mix in North Carolina; 2005–early 2012

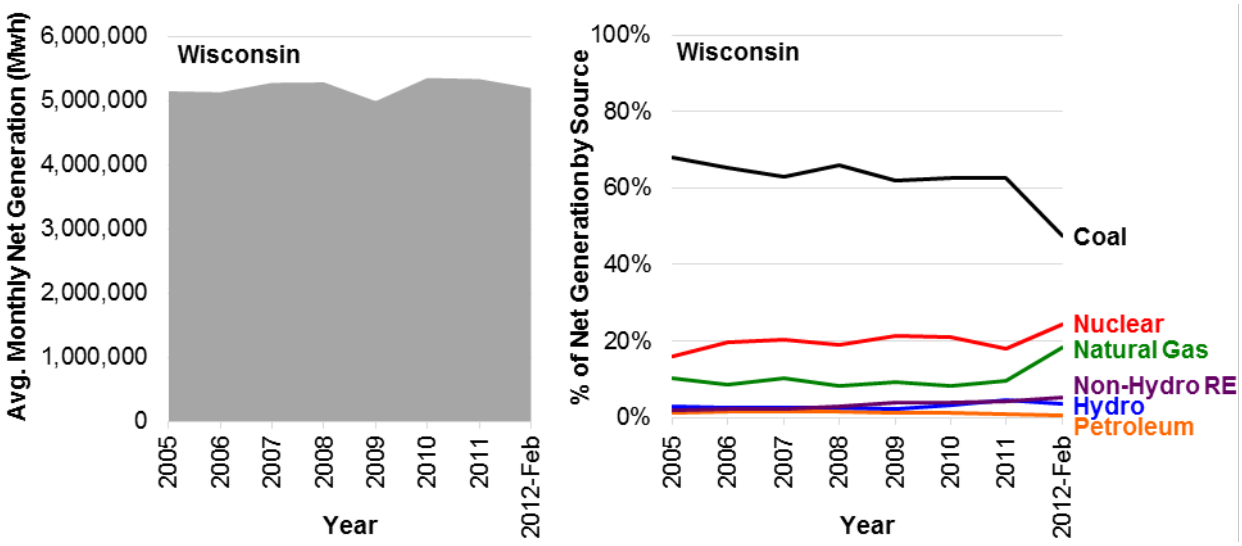


Figure 51. Changes in generation mix in Wisconsin; 2005–early 2012

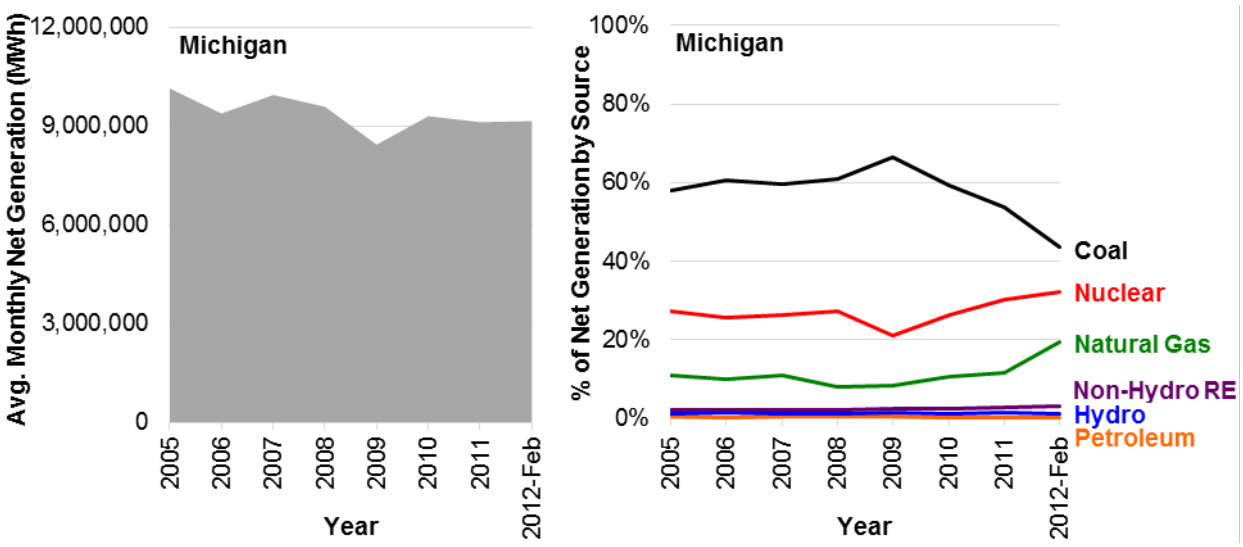


Figure 52. Changes in generation mix in Michigan; 2005–early 2012

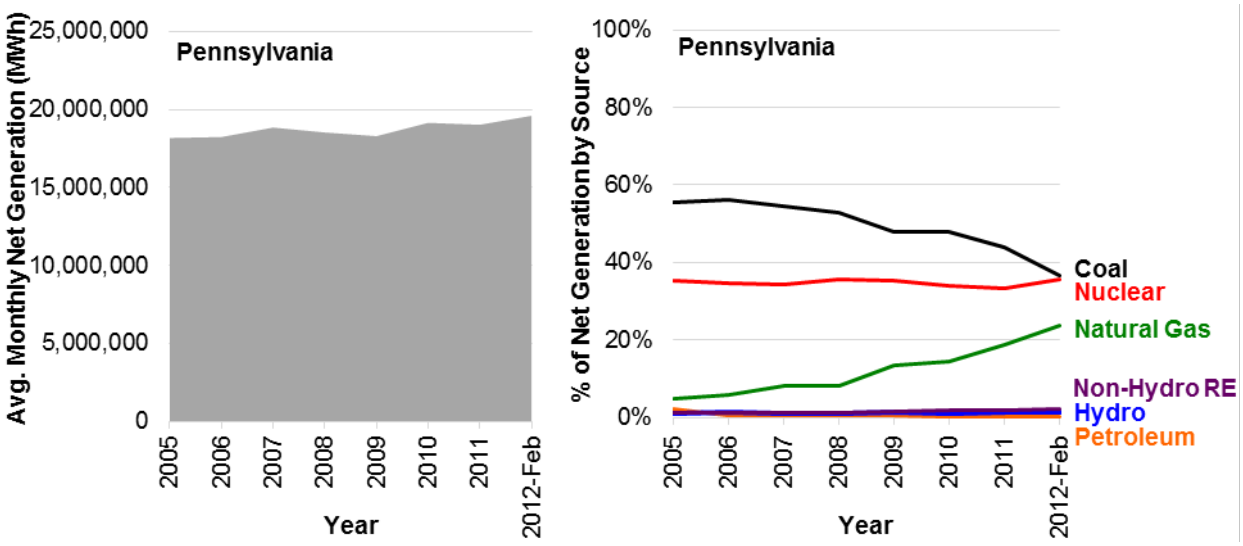


Figure 53. Changes in generation mix in Pennsylvania; 2005–early 2012

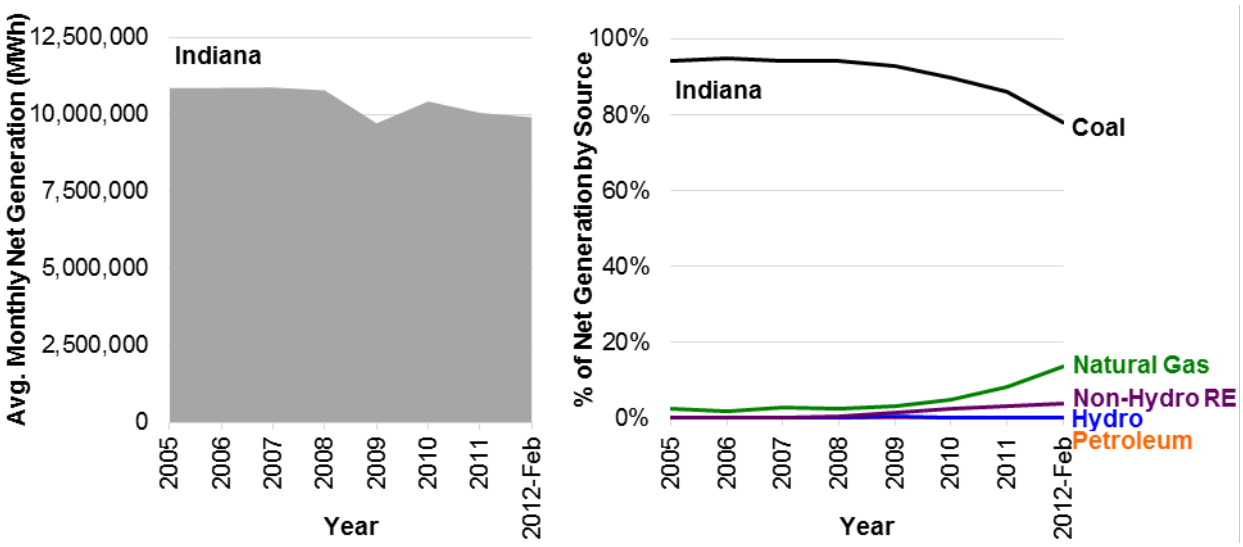


Figure 54. Changes in generation mix in Indiana; 2005–early 2012

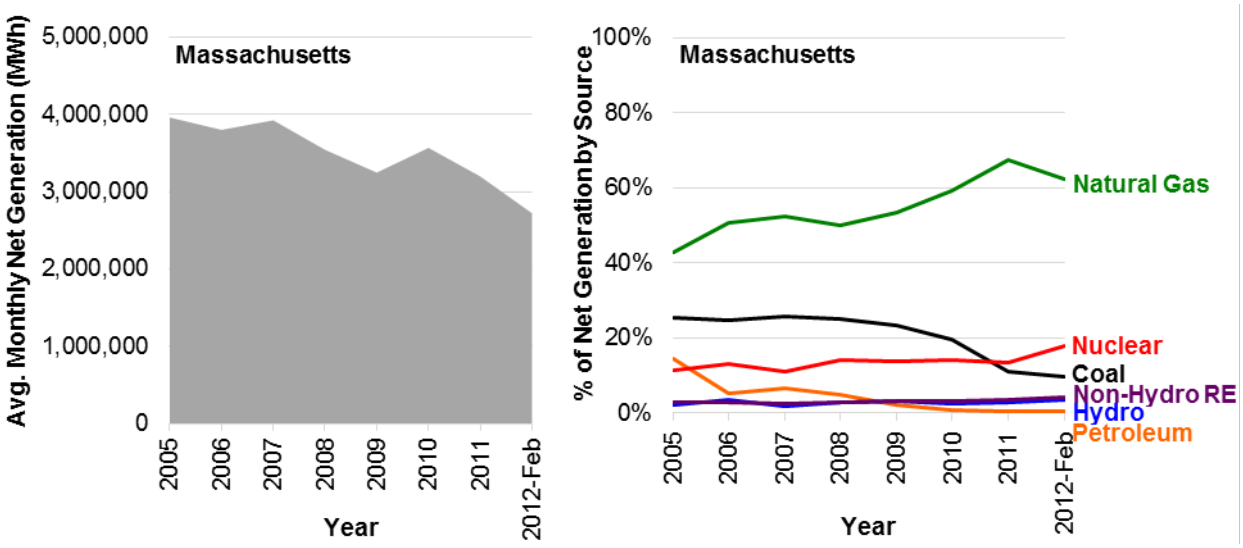


Figure 55. Changes in generation mix in Massachusetts; 2005–early 2012

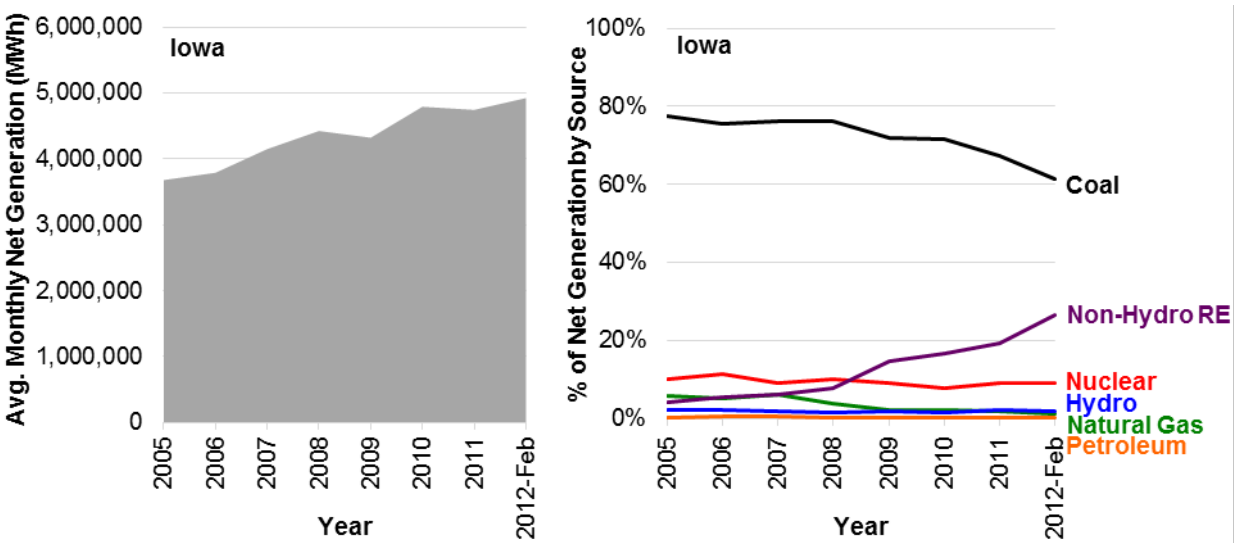


Figure 56. Changes in generation mix in Iowa; 2005–early 2012

Appendix B: Details and Considerations of Methods

This appendix offers details of data, methods, and results for Chapter 1. First, we define several terms relevant to estimating GHG emission factors from the TCEQ inventories.

The *basin* refers to 22 counties under which the Barnett Shale is being developed. Therefore, production in the basin includes production from the Barnett Shale as well as a small amount of additional production from other geological formations contained within the 22 counties.

As defined by the TCEQ (2010: p.23), "any source capable of generating emissions (for example, an engine or a sandblasting area) is called a facility. Thus, facility and emissions source, or 'source' for short, are synonymous." To avoid confusion, we use the term *source* to refer to any individual such facility.

Sources can be characterized into common types called *profiles*. Common examples of profiles include engines, turbines, fugitives, and tanks. Profiles are designated such that the emissions from sources with the same profile can all be estimated with a common method.

The term *site* refers to a physical location for which data are reported to the inventories, where each site consists of multiple different emissions sources. Each site is associated with a unique TCEQ account number and site name. Common examples of types of sites include wells, compressor stations, and gas processing plants. In the Special Inventory, sites are referred to as *leases*.

Production gas refers to the raw, unprocessed gas captured through development activities, and *pipeline gas* refers to the saleable final natural gas product. *Emissions* refer to tons of the specified pollutant(s) emitted per year, whereas *emission factors* refer to the amount of emissions associated with a unit of gas production. This report follows the EPA and TCEQ convention of referring to the set of non-methane, non-ethane hydrocarbons as *VOCs*.

TCEQ Inventory Data

The TCEQ collects an annual, statewide emissions inventory for sources classified as point sources per 30 Texas Administrative Code §101.10. For this study, data were obtained for any sources within this inventory with Standard Industrial Classification (SIC) codes pertaining to the production and processing of natural gas. From the point-source inventory data, GHG emissions are estimated from amine units, boilers, compressor engines, flares, fugitives, glycol dehydrators, heaters, produced-water loadings, produced-water tanks, natural gas turbines, and vents.

To complement the point-source inventory, the TCEQ performs an Area Source Inventory every three years. Data were obtained from the 2008 Area Source Inventory on VOC emissions from pneumatics and produced-water disposal activities, which were not available in the other inventories. These data are reported only at the county level. To combine emissions estimated from pneumatics with those estimated from other inventories, these profile's emissions are adjusted by a factor equal to the change in gas production between 2008 and 2009, at the county level, as shown:

$$Adjustment = \frac{Q_{GWgas,2009}}{Q_{GWgas,2008}}$$

where:

$Adjustment$ = the county-level adjustment from 2008 to 2009 emissions estimates (unitless)

$Q_{GWgas,2008}$ = volume of gas-well gas produced in 2008 (Mcf)

$Q_{GWgas,b,2009}$ = volume of gas-well gas produced in 2009 (Mcf).

In 2009, the TCEQ performed a Special Inventory, for which it requested detailed equipment and production information for stationary emissions sources associated with Barnett Shale oil and gas production, transmission, processing, and related activities. The Special Inventory data cover only stationary emissions sources on site for more than 6 months that were not reported to the 2009 Point Source Inventory. These sources are used in this study to estimate GHG emissions from amine units, boilers, heaters, compressor engines, flares, fugitives, glycol dehydrators, produced-water loadings, produced-water tanks, and vents.

Some emissions sources are not reported to the Special Inventory that nonetheless contribute to the reported site-level total in that inventory. These sources are likely omitted because their emissions are below thresholds for reporting requirements for that inventory. However, although they may be individually negligible, their collective impact is significant—with the sum of the VOC emissions reported for all individual sources equaling only 93% of the sum of all site-level totals reported, across the entire inventory. To account for this underreporting, emissions estimated from Special Inventory data are scaled at the site-level by the inverse of the percentage of site VOCs accounted for by the individual sources reported at each site, as follows:

$$Correction_{site} = \frac{1}{\left[\frac{\sum_{k \in K_n} VOC_k}{VOC_n}\right]} = \frac{VOC_n}{\sum_{k \in K_n} VOC_k} \geq 1$$

where:

$Correction_{site}$ = the site-level correction for non-reported sources (unitless)

VOC_k = the mass of VOCs emitted from source k annually, where $k \in K_n$ is the set of reported sources at site n (tonne/year)

VOC_n = the reported total mass of VOCs emitted from site n annually (tonne/year).

In addition, to account for a stated 98% level of completion for the Special Inventory, all emissions estimated from the inventory's data by the inverse of that completion rate are also adjusted by the inverse of this estimate, as follows:

$$Correction_{inventory} = \frac{1}{98\%} = 1.0204$$

Stages of the Natural Gas Life Cycle

Emissions factors are compiled from the profiles associated with each life cycle stage.

Pre-Production Stage

The pre-production process stage consists of episodic activities related to the preparation of wells. Activities in this stage include the drilling and construction of wells, hydraulic fracturing of shale to stimulate production, and various well-completion activities, which specifically involve the following:

- *Drilling rigs* are used for drilling an oil or gas well. For the purpose of estimating emissions, rigs consist of a collection of diesel-powered engines, which are associated with combustion-generated GHG emissions.
- *Hydraulic fracturing* involves complex liquids, pumps, and trucks for transporting equipment and fluids, which are associated both with combustion-generated GHG emissions and with emissions from off-gassing and fugitives.
- *Well-construction activities* are associated with combustion-generated GHG emissions due to the use of heavy construction equipment.
- *Well-completion activities* involve the release of natural gas from a well before and during the installation of the equipment necessary for recovery of that gas.

Natural Gas Production Stage

The production process stage consists of ongoing activities related to the extraction of natural gas at a gas well. Emissions sources include the following:

- *Compressor engines* are used to maintain well pressure and for other processes at the wellhead. These engines, which typically burn the production gas being extracted, are associated with combustion-generated GHG emissions.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Pneumatics devices* are used to open and close valves and other control systems during natural gas extraction. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Miscellaneous material loading and tanks* refer to sources at production sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Condensate and crude-oil-related sources*, including loading areas and storage tanks, are associated with substantial VOCs but occur in the process chain only after the co-products have been separated from the natural gas process chain. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Natural Gas Processing Stage

The processing process stage consists of ongoing activities related to converting the extraction production gas to the required quality, composition, and compression of pipeline gas. Activities in this stage include separating the condensate co-product from the gas, removing naturally occurring acid gases such as CO_2, lowering the moisture content of the gas, and pressurizing and heating the gas. These activities can occur at either the wellhead or at separate processing facilities, and they are associated with the following emissions sources:

- *Compressor engines and natural gas turbines* are used to pressurize the gas and power other processing activities. These engines, which typically burn the production gas being processed, are associated with combustion-generated GHG emissions.
- *Boilers and heaters*, which typically burn the production gas being processed, are used for processing activities, including the separation of condensate from natural gas and the reduction of ice crystals in the gas stream. Boilers and heaters are associated with combustion-generated GHG emissions.
- *Amine units*, also known as acid gas removal (AGR) units, remove acid gases, such as CO_2, from the production gas to help bring the gas composition to that required for pipeline gas. Amine units are associated with the release of GHGs through venting.
- *Glycol dehydrators* remove water from the production gas to help bring the gas composition to that required for pipeline gas. Dehydrators are associated with the release of GHGs through venting.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the fugitive gas cannot be identified, it is assumed that all fugitives consist of production gas.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the vented gas cannot be identified, it is assumed that assume all vents and blowdowns consist of production gas.
- *Produced water handling*, including loading areas and storage tanks, is associated with gas release emissions, which are assumed identical in composition to water flash gas.
- *Flares* are combustion-based emission control devices used to convert methane from gas-release emissions into CO_2 from combustion emissions. Flares are used as controls on a variety of gas-release emission sources, including produced-water tanks, condensate tanks, and glycol dehydrators.
- *Miscellaneous material loading and tanks* refer to sources at processing sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas-release emissions, which depend on the composition of their identified contents.

- *Separators* are used for processing oil and natural gas; however, only separators at oil sites vent to the atmosphere. Therefore, separators at sites producing only natural gas and not oil should be associated with no VOC emissions. Although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.
- *Thermal oxidizers* are used for processing natural gas, but only a negligible number are reported in the inventories used because of prohibitive capital costs. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Waste Disposal Stage

Natural gas production and processing generates the byproduct of produced water, which must be disposed of because of its high level of contaminants, including salt, hydrocarbons, and various pollutants. Although these activities are associated with stationary and mobile emissions sources, the only tracked emission source for this category is that pertaining to tanks that store the produced water at disposal sites.

Identification of Source Profiles and Attribution to Process Stages

This study identifies the process stage (e.g., production, processing, or transport) to which each source belongs using the provided site names in both inventories. To attribute sources to process stages, the profile associated with each source must first be identified. In the Special Inventory, each source is explicitly identified with the profile under which it was reported to the TCEQ. For the sources in the Point Source Inventory, however, the profile of each source is identified using additional provided information.

The primary source of information for this profile identification is the Source Classification Code (SCC). As described by the TCEQ (2010: p. 90), "A facility's SCC is an eight-digit EPA-developed code that associates emissions determinations with identifiable industrial processes. The TCEQ uses a facility's SCC for modeling, rulemaking, and SIP-related activities; therefore, a facility's SCC must be as accurate as possible. The EPA maintains a current list of SCCs under the 'EIS Code Tables (including SIC)' link at www.epa.gov/ttn/chief/eiinformation.html."

Despite the regulatory importance of the SCC classification, the SCCs provided in the Point Source Inventory do not identify the associated source's profile to the detail necessary for 254 (or 12%) of the 2,177 sources within the 22 counties of the basin. The remaining sources rely on the additional information within characteristics files provided by the TCEQ for specific profiles, such as tanks and engines, and by consistent coding schemes within the Facility Identification Number, which is self-designated by the respondents to the emissions inventory surveys. The study identifies 43 (or 2%) of the sources by characteristics files and 211 (or 10%) by the Facility Identification Number, which represent 1.4% and 2.0%, respectively, of the total VOCs reported for all reported sources within the 22 counties of the basin.

For those source categories that can exist at multiple types of process stages, the default assumption is that a location is a production facility (i.e., a well site), unless the site name ("Lease Name" in the Special Inventory and "Site Name" in the Point Source Inventory) is identifiable as belonging to a facility type associated with the processing stage, such as a

processing plant or a compressor station, or with the disposal stage, such as salt-water disposal sites. In addition, four sites identified as disposal by this method are reassigned to production due to non-zero gas-well gas production statistics, which means all sources at those four sites are assigned to production, although some presumably relate to water-disposal activities instead. To the extent that this allocation method introduces an error, that error is not the omissions of emissions from the overall estimates, but rather, the incorrect allocation of total emissions across different process stages.

TCEQ inventory data are available for some pre-production processes, but such data cannot be used for original analysis because it incompletely covers the life cycle stage. Also, literature estimates available for supplementing the original analysis do not segregate between different processes as would be necessary for incorporation with the original analysis.

This study uses site-level allocation to select sources into the processing stage. The same site name in both the Point Source Inventory and the Special Inventory is used to positively identify processing sites, with the default stage for the remaining sites being production. Of the processing sites, following the recommendation of the TCEQ,[149] those that do not have any processing-related sources are designated as transmission sites, and accordingly, are considered outside the boundary of this analysis.

After site-level identification, processing-type sources at production sites are associated with the processing life cycle stage. Such equipment includes heaters, boilers, amine units, and dehydrators. In addition, following Stephenson et al. (2011), this study assumes that all tanks—and therefore, also all loading (which occurs after tanks in the process chain)—belong to the processing stage and not the production stage, regardless of where the tanks are physically located.

To avoid double counting with third-party emission factors for transmission, transmission sites (identified as non-well facilities without any processing equipment) are omitted from the analysis of TCEQ inventory data. Specifically, 833 sources are omitted from the special inventory and point-source inventory analyses as pertaining to transmission. This represents 5% of the total sources from these inventories, or about 10% of the CO_2 and the CH_4 emissions from these inventories.

Spatially Explicit Estimation of Production Gas Composition

An important differentiation of this study's estimation approach from similar studies is that this study attempts to estimate the composition of production gas in a specific area. The methods used in this study improve upon the use of a general gas composition developed from national-level averages by 1) developing a novel gas composition estimate that is specific to a region of interest, but also by (2) further recognizing the spatial heterogeneity of this composition within the 22-county basin. Specifically, this method collects data on speciation of production gas and the flash gas from produced water to calculate the CO_2 and CH_4 emissions from numerous sources in the TCEQ Special Inventory using spatially explicit estimates of gas composition. The following factors come from this speciation:

[149] Personal communication (TCEQ 2012).

f_C == the fraction of carbon in the production gas by mass (unitless)

f_{CO_2}= the fraction of CO_2 in the production gas by mass (unitless)

f_{CH_4}= the fraction of CH_4 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

HHV = the higher heating value of the production gas (Btu/scf).

These data are collected from supplementary files from the TCEQ's Barnett Shale Phase Two Special Inventory. As part of the quality assurance procedures of this Special Inventory, the TCEQ requested supplementary files from respondents. These files consist of a record of the written correspondence between the respondent and TCEQ, which varies considerably in content and form across different respondents. To estimate gas composition across the Barnett Shale region, this analysis focuses on included reports from independent laboratory analyses of the gas compositions, identifiable as pertaining to relevant samples of either production gas or of leaked gas in the form of vents or gaseous fugitives. Due to the nature and the origin of these files, the inclusion and reporting of such gas content analyses are not consistent across different files. Detailed supporting information—such as the specific origin of the sample tested, both with respect to process and geographic location—is not consistently available; therefore, it cannot be confirmed in many cases.

Given the disparate nature of these files and the inconsistent reporting of identifying information, these analyses therefore omit many reported composition analyses due to a lack of clarity regarding the geographical or process-source of the analyzed sample. Instead, those analyses are retained that can be assigned a location and content type with a reasonable level of confidence. The creation of these supplementary files and selection of a subset of them for obtaining gas composition analyses is neither random nor intended to be representative; therefore, such elimination does not introduce selection bias created by such omissions. The randomness of the errors will lead to attenuation bias of the analytical results, which is typical in cases of measurement error where there is no reasonably expected consistent bias to the error. In this context, measurement error should reduce the impact of calculating the spatial variation in gas content versus using the central estimate of gas content across the entire region.

In a related limitation of this method, we identified a substantial number of duplicate analyses in these records associated with different lease locations and even across different counties, based on identifying identical laboratory-assigned sample numbers and identical compositions to the reported level of precision provided by the same company. We attempted to identify and remove duplicate analyses; but misspecification in the dataset is possible because it is unclear in some cases which analysis is the original source.

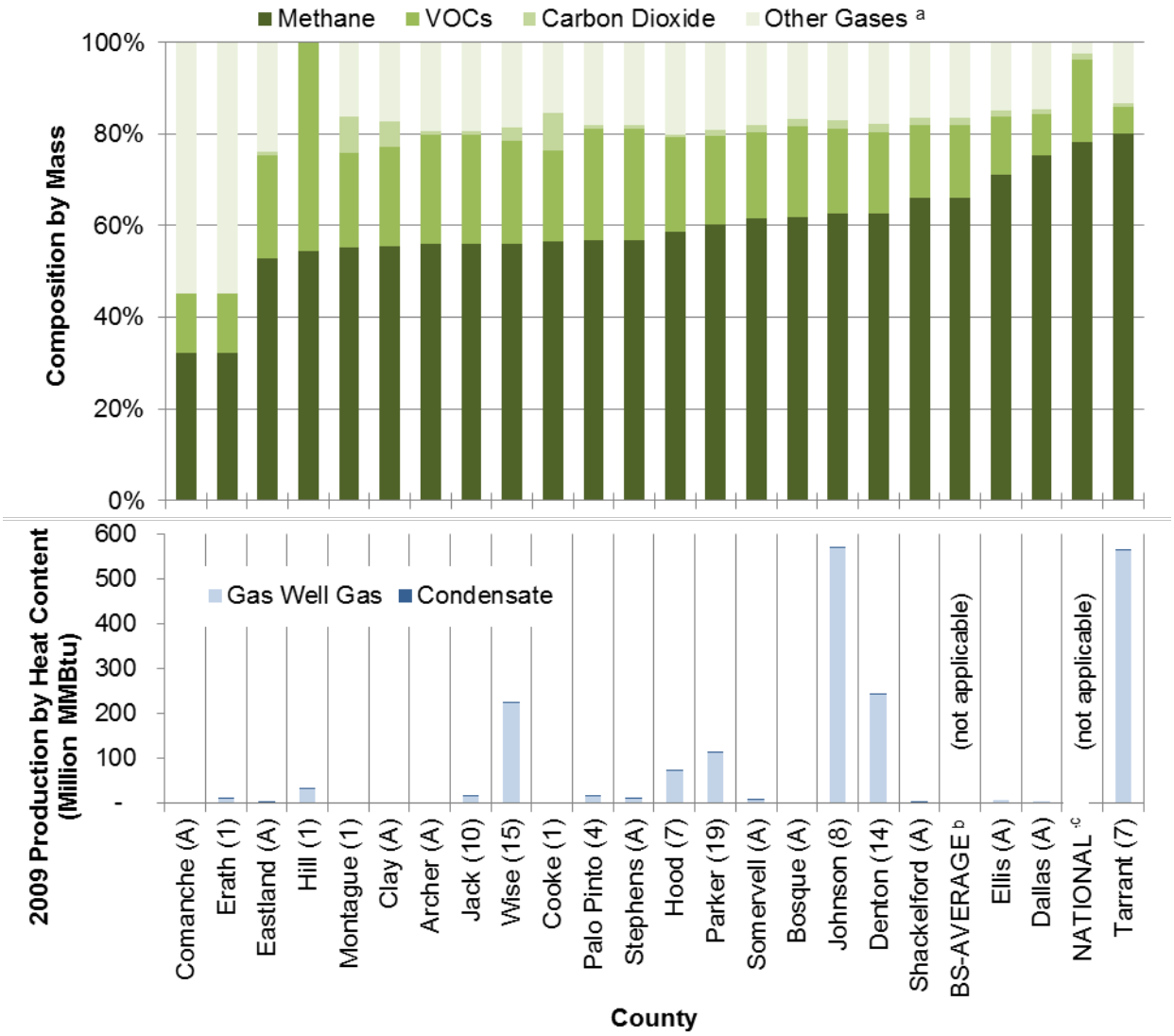
From these data, county-level estimates of gas composition are developed separately for production gas, condensate flash, oil flash, and produced-water flash. Counties with one or more available composition analyses are assigned the composition analysis with the median level percentage-by-weight of methane in the reported composition analyses. In addition to providing a central estimate of gas composition for each county, this estimation of central tendency buffers the results against the impact of misspecifications of location described above.

We used a production-weighted average of the median adjacent counties' estimates with reported composition analyses for counties with no reported composition analyses. A production-weighted average of all reported composition analyses across the Barnett Shale region is used for the few counties with no reported composition analyses either for that county or for all adjacent counties.

In addition to attempting to err on the side of caution in including gas composition analyses, we estimated the sensitivity of the analysis to the gas composition by comparing results of this study's method—which uses the county-level gas composition estimates as described above for emissions estimates—to results using the same emissions estimation calculations with two different sets of alternative gas compositions: one reflecting the production-weighted average of this study's gas analyses from the TCEQ Special Inventory supplementary files and another reflecting standard assumptions of gas composition identified in the literature. Given the imperfect source of information and the assumptions on which this study's analysis depends, substantial variation between these different methods makes a compelling case for the importance of using geographically appropriate gas compositions that are accurate to a reasonably fine scale when estimating GHG emissions from natural gas extraction and production. This study's approach provides the best-available approximation, using the best-available data, of a spatially explicit definition of gas compositions relevant to estimating GHG emissions. To improve on this analysis, future data collection efforts should emphasize the measurement and reporting of spatially explicit gas compositions.

Estimated Composition of Production Gas

The top panel of the Figure 57 presents the estimates of the main components of production gas from each of the 22 counties of the Barnett Shale play, as well as the Barnett Shale production-weighted average and the national average commonly used in the literature. Key parameters and production statistics for each county are also presented in Table 17 and Table 18. Components, which are shown in their mass percentage within the production gas, include methane, VOCs (as defined above to include all non-methane and non-ethane hydrocarbons), CO_2, and other gases. Primary gas species represented in the "other" category are nitrogen and ethane. The lower panel of Figure 57 depicts, for reference, the production volume for each county. Shown after each county's name is the number of unique analyses collected for that county—with counties estimated by a weighted average of adjacent county's compositions designated with an "A," rather than a number.



[a] "Other" gas include nitrogen, ethane, and any other non-methane, -VOC, or -carbon dioxide gases reported
[b] BS-AVERAGE refers to the production-weighted average gas composition in the 22-county Barnett Shale basin
[c] NATIONAL refers to the national average composition commonly used in the literature (EPA 2011)

Figure 57. Composition of production gas by county

NOTE: number of gas composition samples is reported in parentheses following each county name, where "A" denotes counties with no samples such that samples from adjacent counties were substituted.

The gas composition estimates for the six counties that represent the vast majority of production volumes are supported by high numbers of estimates. However, reflecting this study's non-random, targeted strategy for seeking these estimates, many of the estimates for the remaining counties come from either a small number of estimates or the weighted average of adjacent counties. Specifically, no usable estimates were found for 10 of the 22 counties.

The uncertainty inherent to this approach for obtaining gas analyses is highlighted by the difference in gas composition in Comanche County and Erath County versus the majority of the

counties. These compositions, which are both estimated by a single analysis from Erath County, show an abnormally large presence of nitrogen—and thus, are suspect of contamination with ambient air. However, the available information offers no verifiable support of such suspicion. The presence of such uncertainty emphasizes the need for better documentation of gas composition if this factor is to be used in further analysis or other factors, such as implementing regulations. However, it is important to note that the very low production volumes associated with these two counties means that their analyses have a nearly negligible impact on the overall results.

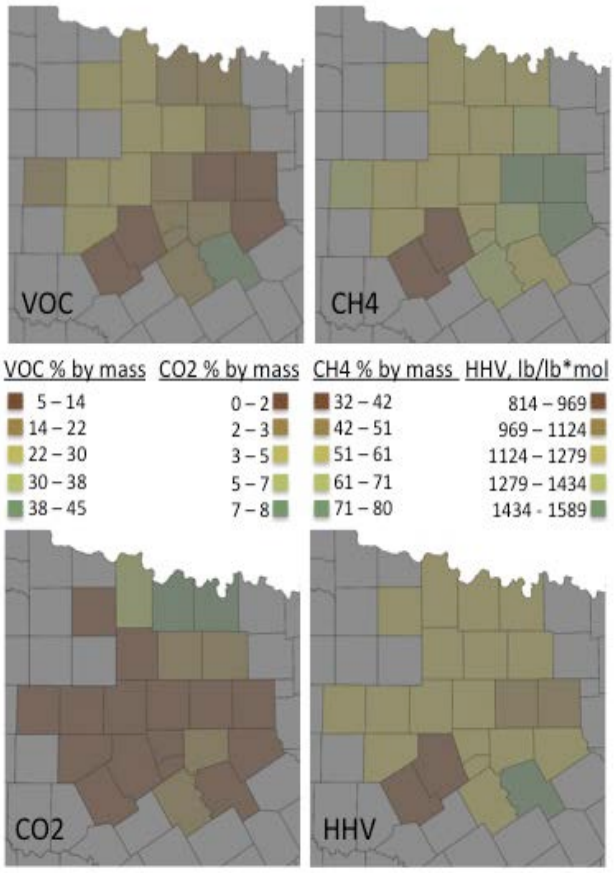


Figure 58. Variation among gas compositions across the 22 counties of the Barnett Shale play

The variation among gas compositions is demonstrated as being patterned across the 22 counties of the Barnett Shale play differently for different key parameters, as shown Figure 58. Such patterned distribution is to be expected if the observed variation reflects geological heterogeneity rather than simply uncertainty in the sampling methodology. The counties represented by weighted averages are located primarily on the western and eastern periphery of the region; therefore, the central north-south corridor represents both the majority of production and the estimates supported by larger samples. Along this corridor, parameters can be observed to vary relatively smoothly, although the differentiation between different parameters demonstrates the complexity of the variation in gas composition. In other words, this map demonstrates that gas composition varies across space, but also, it suggests that the complexity of this variation might extend to finer scales than the county level.

Table 17. Composition of Production Gas and Produced-Water Flash Gas in Barnett Shale Counties

	Production Gas						Produced-Water Flash Gas		
County	Molecular Weight (lb/lb-mole)	Higher Heating Value (Btu/scf)	Carbon Content (% by mass)	Methane (% by mass)	VOCs (% by mass)	Carbon Dioxide (% by mass)	Methane (% by mass)	VOCs (% by mass)	CO_2 (% by mass)
Comanche	23.86	813.78	43.6	32.2	12.9	0.2	33.5	24.8	31.1
Erath	23.86	813.78	43.6	32.2	12.9	0.2	43.1	34.8	7.8
Eastland	22.07	1,188.04	69.3	52.8	22.4	0.7	27.7	52.0	6.4
Hill	26.92	1,589.66	79.2	54.5	45.6	0.0	38.3	5.8	54.8
Montague	21.99	1,216.13	72.6	55.1	20.7	8.1	53.3	17.4	13.0
Clay	21.86	1,229.52	73.2	55.4	21.8	5.5	26.7	6.2	61.1
Archer	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Jack	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Wise	21.79	1,274.01	75.5	56.0	22.6	2.9	59.5	19.9	1.9
Cooke	21.76	1,199.75	72.2	56.5	20.0	8.1	46.8	17.2	18.0
Palo Pinto	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Stephens	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Hood	21.19	1,248.33	75.2	58.5	20.8	0.6	48.2	29.1	8.2
Parker	20.85	1,242.78	75.9	60.3	19.3	1.2	16.3	52.4	1.1
Somervell	20.71	1,224.89	75.3	61.5	19.0	1.6	40.1	10.0	46.4
Bosque	20.89	1,236.59	75.5	61.7	19.8	1.7	38.3	5.8	54.8
Johnson	20.57	1,226.04	75.8	62.5	18.7	1.8	38.3	5.8	54.8
Denton	20.54	1,218.65	75.4	62.5	17.9	1.9	34.8	14.5	33.3
Shackelford	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
Ellis	19.41	1,159.09	74.6	71.0	12.9	1.3	32.5	19.4	43.2
Dallas	18.63	1,112.74	73.9	75.4	9.0	1.1	23.9	39.5	23.1
Tarrant	17.92	1,072.83	73.3	80.2	5.6	0.9	20.7	46.7	20.1
Barnett Shale Average[a]	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
National Average[b]	17.40	1,027.00	75.0	78.3	17.8	1.5			

[a] Barnett Shale average is a production-weighted average of counties for which original gas compositions could be obtained

[b] National average production gas reported in EPA (2011)

Table 18. 2009 Production Volumes from Barnett Shale Counties

Heat Content (MMBtu)

County	Oil	Condensate	Casinghead Gas	Gas-Well Gas	Combined Gas	County Total
Archer	6,018,590	737	458,853	21,351	480,205	6,499,532
Bosque	0	98	0	354,480	354,480	354,578
Clay	3,514,046	37,503	494,346	351,615	845,961	4,397,511
Comanche	31,946	8,046	54,996	513,967	568,963	608,955
Cooke	11,740,372	43,729	4,394,033	485,521	4,879,554	16,663,655
Dallas	0	0	0	4,923,785	4,923,785	4,923,785
Denton	486,574	2,516,461	1,023,276	241,825,407	242,848,683	245,851,717
Eastland	1,491,957	314,574	834,641	3,916,728	4,751,369	6,557,901
Ellis	6,125	0	0	7,552,672	7,552,672	7,558,797
Erath	34,829	218,806	123,445	10,657,734	10,781,179	11,034,814
Hill	7,267	471	0	31,983,129	31,983,129	31,990,868
Hood	16,553	2,660,894	156,109	72,781,121	72,937,230	75,614,677
Jack	3,999,135	878,025	2,261,462	16,294,739	18,556,202	23,433,361
Johnson	0	318,855	0	570,667,212	570,667,212	570,986,067
Montague	11,979,935	34,090	9,682,791	350,290	10,033,081	22,047,106
Palo Pinto	3,232,091	525,481	6,957,154	16,076,018	23,033,172	26,790,743
Parker	73,886	1,672,455	730,069	112,696,107	113,426,176	115,172,517
Shackelford	4,108,140	66,203	849,166	2,234,492	3,083,658	7,258,000
Somervell	0	65,812	0	7,485,891	7,485,891	7,551,704
Stephens	12,811,777	291,120	3,525,626	11,751,922	15,277,548	28,380,445
Tarrant	0	241,264	0	563,514,077	563,514,077	563,755,341
Wise	2,400,875	5,017,491	6,426,006	222,654,526	229,080,532	236,498,898
Basin Total	**61,954,098**	**14,912,113**	**37,971,973**	**1,899,092,788**	**1,937,064,761**	**2,013,930,972**

Co-Product Allocations

In addition to natural gas, the sources reported in the TCEQ inventories are associated with the marketed products of condensate and, in some cases, oil. In fact, gas companies are focusing all of their new investment in areas with wet gas, which has a higher VOC content, for its higher value. The principle of co-product allocation is that when there are multiple valued products from a single system, the burdens of that system should be shared among all products. This study uses energy-based co-product allocation, which weights the burdens (i.e., emissions) of each process by the ratio of energy contained in all co-products that is embodied in the product of interest.

The factor that is applied depends on the relevant life cycle stage of a source. For production sources, we use the finest grain of spatial resolution available. Specifically, emissions for all production sources in the Special Inventory are allocated among condensate, oil, and natural gas products at the *site level* using site-level production statistics, as follows:

$$Allocation_{site} = \frac{\left(Q_{GWgas,s}\right) * HHV_{pipe\ gas}}{\left(Q_{GWgas,s} + Q_{Cgas,s}\right) * HHV_{pipe\ gas} + Q_{oil,s} * HHV_{oil} + Q_{cond,s} * HHV_{cond}}$$

where:

$Allocation_{site}$ = the site-level, energy-basis co-product factor for gas produced by gas wells (unitless)

$Q_{GWgas,s}$ = the volume of gas-well gas produced at the site annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced at the site annually[150] (Mcf)

$Q_{oil,s}$ = the volume of oil produced at the site annually (bbl)

$Q_{cond,s}$ = the volume of condensate produced at the site annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas)

- 1,027,000 Btu/Mcf for pipeline-quality gas

HHV_{oil} = the energy content of oil

- 5,800,000 Btu/bbl for crude oil[151]

HHV_{cond} = the energy content of condensate

- 5,418,000 Btu/bbl for plant condensate.[152]

As Figure 59 depicts, the majority of these site-level co-product allocation factors are at or close to 1—reflecting the fact that the majority of production within these counties is natural gas. However, Figure 59 also shows that 15% of the sites included within the Special Inventory produce no gas-well gas and, accordingly, the emissions from these sites do not contribute to the total emissions allocated to natural gas.

[150] Note that casinghead gas is a natural gas that is a co-product of oil production (produced by oil wells).
[151] API (2009), Table 3-8
[152] EIA (2011), Appendix A

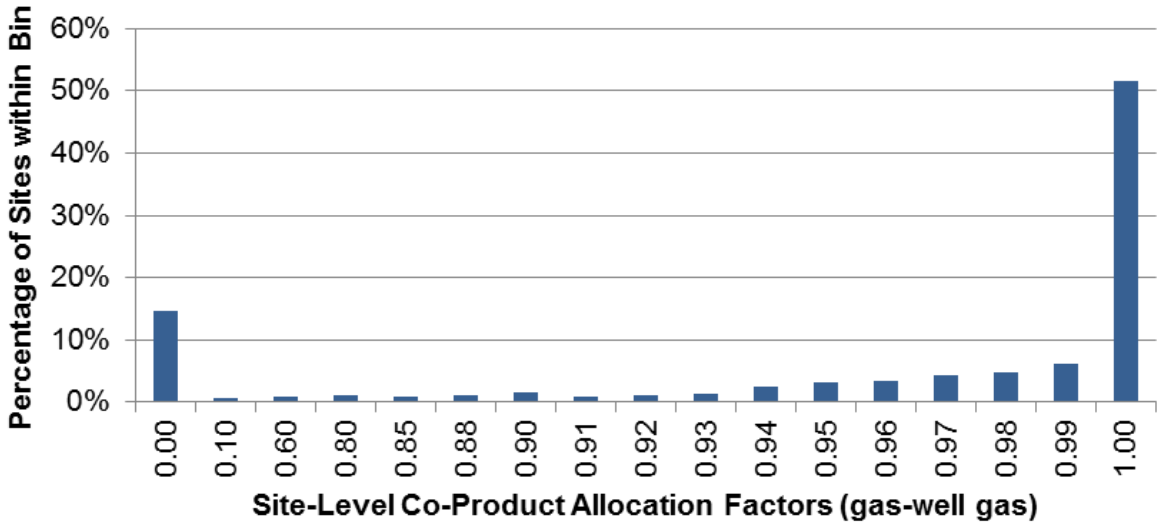


Figure 59. Distribution of site-level emissions allocated to gas

Site-level production statistics are not available for sites in the Point Source Inventory, and relevant counties have negligible oil production, lowering the chance that production-stage point sources emissions are associated with oil production. Therefore, emissions are allocated for all production sources in the Point Source Inventory among condensate and natural gas products at the *county level* using county-level production statistics (Figure 60). Similarly, Area Source Inventory data are available only at the county-level; so they are most appropriately allocated among co-products at this scale. This allocation is calculated as follows:

$$Allocation_{county} = \frac{Q_{GW\ gas,c} * HHV_{pipe\ gas}}{Q_{GW\ gas,c} * HHV_{pipe\ gas} + Q_{cond,c} * HHV_{cond}}$$

where:

$Allocation_{county}$ = the county-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,c}$ = the volume of gas-well gas produced in the county annually (Mcf)

$Q_{cond,c}$ = the volume of condensate produced in the county annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

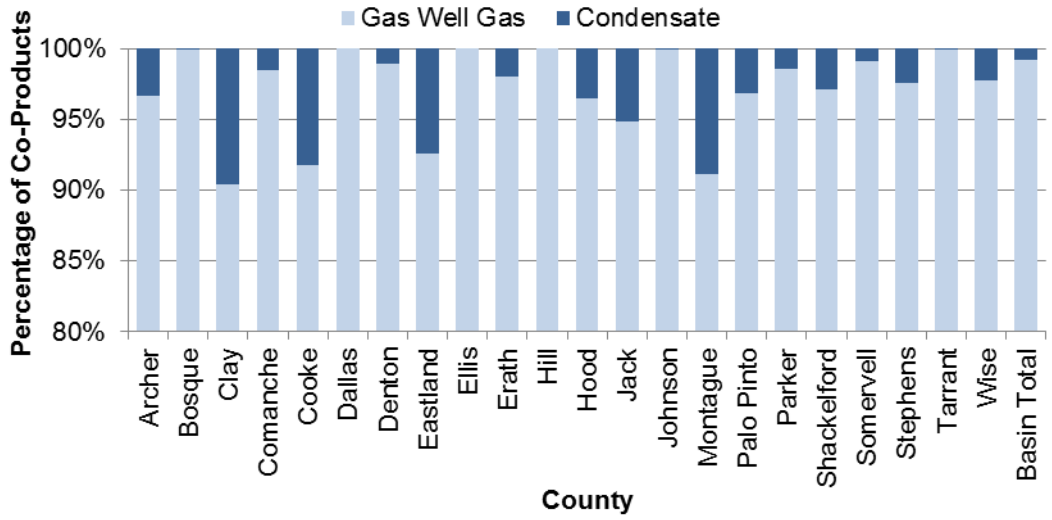


Figure 60. County-level gas production co-products by heat content

Regardless of the inventory in which the sources are described, emissions from processing sources are allocated at the *basin level* using basin-level production statistics. The relevant co-product allocation includes casinghead gas volumes as well as gas-well gas volumes because all natural gas—regardless of whether the production source is a gas or oil well—is processed at these sites. Some of these processing steps might occur after the condensate is separated, but the order of processing steps varies by site and is not identifiable in the data of the TCEQ inventories. Therefore, co-products are allocated as follows:

$$Allocation_{basin} = \frac{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas}}{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas} + Q_{cond,b} * HHV_{cond}}$$

where:

$Allocation_{basin}$ = the basin-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,b}$ = the volume of gas-well gas produced in the basin annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced in the basin annually (Mcf)

Q_{cond}, b = the volume of condensate produced in the basin annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

Note that some processing profiles pertain to processes that might occur after the condensate is separated from the process stream and, therefore, should not be partially allocated to that co-product. However, the specific order of processing steps is not readily identifiable in the data. In addition, the impact of neglecting this is small because condensate contributes less than 1% to the denominator of the allocation factor (Figure 61).

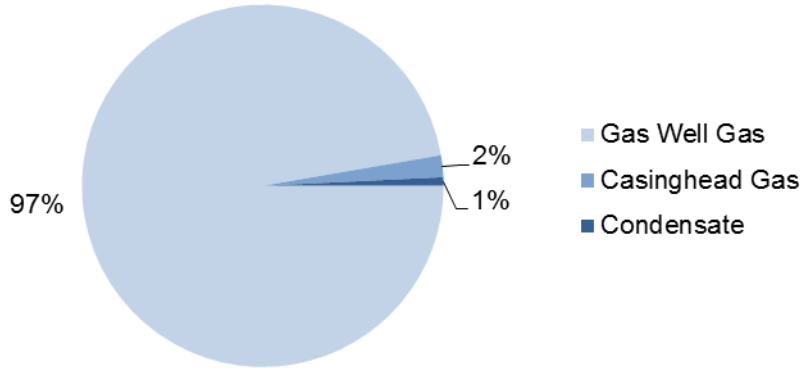


Figure 61. Basin-level gas processing co-products by heat content

In addition, because condensate and crude oil are separately marketable products, co-product allocation means that the substantial VOCs in the TCEQ Inventories corresponding to the storage and handling of these co-products—once separated from the natural gas stream—are outside the boundary of natural gas production and processing. Therefore, this study omits about 25% of the individual sources reported in the two inventories, which collectively represent 60% of the total reported VOC emissions, because they are associated only with the production and processing of the co-products of crude oil and condensate.

Regarding the co-production of oil within the counties of the basin, note that the 84 sites identified as production sites in the Point Source Inventory are all located within the 7 counties listed below—which include their respective percentage of the co-product energy associated with oil production:

- Denton: 0.2% from oil
- Hood: 0.0% from oil
- Johnson: 0.0% from oil
- Palo Pinto: 12.1% from oil
- Parker: 0.1% from oil
- Tarrant: 0.0% from oil
- Wise: 1.0% from oil.

With the exception of Palo Pinto County, these values suggest the co-production of oil represents a negligible amount, and the sole production site in Palo Pinto County identified in the Point Source Inventory is a gas well, associated with zero oil production, as verified through an online query of the Texas Railroad Commission's production statistics database. Therefore, this study does not attribute any production-related emissions from the Point Source Inventory to a co-product of oil.

Overall, 1% of the estimated GHG emissions are allocated to condensate instead of natural gas. For comparison, note that Skone et al. (2011) base their co-product allocation on their reported

12% non-methane VOC whereas Stephenson et al. (2011) report 16.4% allocation to condensate, ethane, and liquid petroleum gas. However, this proportion varies substantially across the 22 counties of the Barnett Shale play, as shown in Figure 62. Even among top-producing counties, which are shown by the larger bars in the lower panel of the figure, significant portions of GHGs are attributed to condensate instead of natural gas—ranging from 0.5% condensate for Johnson County and Tarrant County to 1.7% for Wise County. More strikingly, only 91.7% and 92.7% of emissions in Montague County and Cooke County, respectively, are associated with the natural gas product.

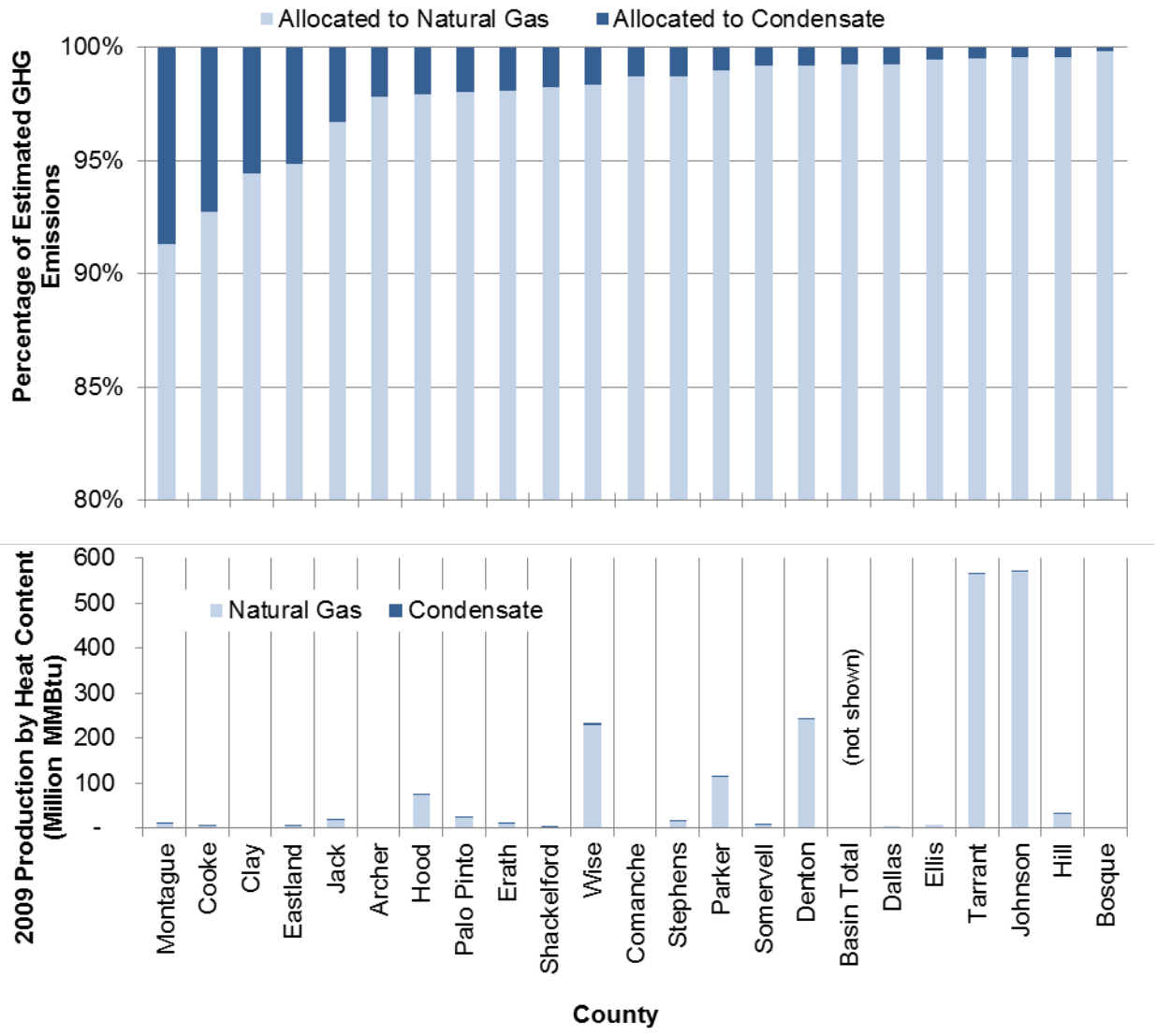


Figure 62. Proportion of GHG emissions associated with co-products

Estimation of Emissions by Source Profile

Emissions estimations generally use a "black box" approach, where a profile is associated with a life cycle stage by the purpose it serves rather than by its physical location. However, for those profiles possibly related to multiple stages, such as compressor engines and fugitives, each source is associated with the life cycle stage by the categorization of the site at which the source is found.

In general, emission sources can be categorized into two broad types of profiles: *combustion sources* and *gas-release sources*, with certain unique characteristics of certain processing activities leading to a third category. A tiered approach is used to calculate emissions, in which secondary calculation methods are applied when the data requirements for preferred methods are not met for an individual source. If neither method is possible with the available data, median estimates from other sources of the same profile are used. Overall, preferred methods were used for 79% of sources, secondary for 18%, and tertiary for the remaining 2%. The following paragraphs introduce the main categories and methodologies, which are adapted from the methodologies presented by ENVIRON (2010), API (2009), and EPA (1995), as appropriate. These emissions estimates include both routine and non-routine emissions estimates for 2009.

Combustion sources include compressor engines, boilers, heaters, and turbines. In these profiles, CO_2 emissions primarily come from chemical reactions during combustion, and methane emissions primarily come from the incomplete combustion of the combusted fuel. The composition of the fuel gas therefore influences the emissions, as do source characteristics and details of the level of usage of the source. This study's preferred methodology for calculating emissions from combustion sources is based on the quantity of fuel combusted and the composition of the fuel gas—as determined by a county-level estimation of production gas composition, assuming that the natural gas fuel used in all cases is the production gas at that site.

Gas leakage sources include both intentional and unintentional releases of gas. Within this category, there is a differentiation between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from dispersed leaks and therefore is less feasible to control. This study's preferred methodology for calculating GHG emissions from gas-release sources therefore is based on the reported emissions of total VOCs and the ratio of CO_2 and CH_4 to VOCs in the released gas, which means it depends on the speciation of the released gas. Estimating these emissions assumes that production gas is the released gas in all cases, except when the profile is associated specifically with produced water handling; in this case, the released gas is assumed to be equivalent to the produced-water flash gas.

In addition, some processing sources require specialized estimation methods. For example, AGR units specifically remove CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. Specifically, AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas.

The estimation of GHG emissions for different profiles consistently assumes that the speciation of production gas varies spatially based on the geology of the Barnett Shale. This variation can be reasonably represented by variation at the county level, as spatially interpolated from the

sample of gas composition analyses collected from supplementary Special Inventory files provided by the TCEQ.

Similarly, all natural gas represented in the following methodologies is assumed to be the production gas, except where explicitly noted (as in the AGR profile calculations). The speciation of this production gas is spatially explicit to the county level for production sources and the basin average composition for processing sources.

In addition, many profiles rely on standardized emission factors, which represent industry-level averages across the specifics of individual equipment. The majority of these emission factors are obtained from the EPA's AP-42, Compilation of Air Pollutant Emission Factors (EPA 1995). Factors applied are shown in Table 19.

Table 19. EPA's AP-42 Compilation of Air Pollutant Emission Factors

Profile	CO_2 Emission Factor	CH_4 Emission Factor	VOC Emission Factor
External Combustion, Natural Gas[a]	118 lb/MMBtu	2.25e-3 lb/MMBtu	5.39e-3 lb/MMBtu
External Combustion, Diesel[b,c]	2710 $kg/10^3m^3$	0.0062 $kg/10^3m^3$	0.0240 $kg/10^3m^3$
Internal Combustion, Natural Gas: 2-Stroke Lean-Burn[d]	110 lb/MMBtu	1.45 lb/MMBtu	1.20e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Lean-Burn[e]	110 lb/MMBtu	1.25 lb/MMBtu	1.18e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Rich-Burn[f]	110 lb/MMBtu	2.30e-01 lb/MMBtu	2.96e-02 lb/MMBtu
Internal Combustion, Diesel	164 lb/MMBtu[g]	3.15e-02 lb/MMBtu[h]	3.19e-01 lb/MMBtu[h]
Internal Combustion, Gasoline	154 lb/MMBtu[g]	1.89e-01 lb/MMBtu[h]	1.911e00 lb/MMBtu[h]
Natural Gas Turbine[I]	110 lb/MMBtu	8.60e-03 lb/MMBtu	2.10e-03 lb/MMBtu
Stationary Large-Bore Diesel Engines[j]	2745 $kg/10^3m^3$	0.1548 $kg/10^3m^3$	1.7415 $kg/10^3m^3$

[a] EPA (1995), Table 1.4-2
[b] Diesel fuel is also used as a proxy for crude oil.
[c] EPA (1995)
[d] EPA (1995), Table 3.2-1
[e] EPA (1995), Table 3.2-2
[f] EPA (1995), Table 3.2-3
[g] EPA (1995), Table 3.3-1
[h] EPA (1995), Table 3.3-1, where total organic compounds from Exhaust = 2.1 for gasoline and total organic compounds from Exhaust = 0.35 for diesel, and Table 3.4-1, which states that total organic compounds by weight is 9% CH_4 and 91% non-CH_4 for the one diesel engine measured
[I] EPA (1995), Table 3.1-2a
[j] EPA (1995)

Tiered Methods Counts

This study applies a tiered approach to the estimation of GHG emissions, in which preferred methods are applied when available data allow, and secondary methods otherwise. For those sources unable to use either method, we apply a tertiary method of assigning the median estimate for that profile. Table 20 demonstrates the count of the usability of each method across the two main inventories.

Table 20. Count of Usability for each GHG Emissions Estimation Method for CO_2 and Methane

	CO_2			Methane		
	Method 1	**Method 2**	**Method 3**	**Method 1**	**Method 2**	**Method 3**
Amine Units	n/a	–	–	4	–	–
Blowdowns and Vents	1,366	68	10	1,366	68	10
Boilers and Heaters	277	–	32	277	–	32
Engines	1,467	364	35	708	1,133	25
Flares	21	–	15	n/a	–	–
Fugitives	4,247	–	24	4,247	–	24
Glycol Dehydrator	79	21	14	79	21	14
Produced-Water Loading	1,948	–	11	1,948	–	11
Produced-Water Tanks	4,429	–	106	4,429	–	106
Special Inventory Total	13,834	453	247	13,058	1,222	222
Engines	–	673	–	–	673	–
Flares	–	17	–	n/a	–	–
Other combustion	–	264	–	–	264	–
Gas Leakage Sources	–	735	–	–	735	–
Produced-Water Tanks	90	–	–	90	–	–
Point-Source Inventory Total	90	1,689	0	90	1,672	0
Combined Total	13,924	2,142	247	13,148	2,894	222

General Leakage Profiles

General leakage profiles include *blowdowns*, *fugitives*, *pneumatics*, and *vents*. Data on blowdowns, fugitives, and vents are obtained from both the Point Source Inventory and the Special Inventory, and data on pneumatics are obtained from the Area Source Inventory. Although these different sources have different causes, they are calculated by similar methods. Because these profiles occur at both production and processing sites, sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of gas released and this study's estimate of the composition of that gas. Where data are not available on volume of gas released, the secondary method uses the reported volume of VOC emissions and a ratio of the GHG to VOCs in the gas composition. These methods for calculating CO_2 and methane emissions for leakage sources are adapted from ENVIRON's (2010) discussion of leakage sources, including well-completion venting, well blowdowns, permitted fugitives, and unpermitted fugitives.

Note that unlike most profiles, inventory data on pneumatics come from the Area Source Inventory, which provides county-level data without individual source counts. Therefore, although emissions from pneumatics are calculated using methods analogous to other leakage profiles, such calculation occurs at the county level based on aggregated, county-level emissions reported in the inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CO_2} * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (scf/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CO_2} = the fraction of CO_2 in the leaked gas by mass (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CH_4} * \frac{1tonne}{2204.62lb}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (tonne/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CH_4} = the fraction of CH_4 in the leaked gas by mass (unitless).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Compression Engines Profile

Data on compressor engines are obtained from the Special Inventory and the Point Source Inventory. Because these profiles occur at both production and processing sites, the sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel, as well as the engine characteristics in the case of methane. Where the volume of fuel combusted is not available, the secondary method for CO_2 emissions uses engine characteristics and operations data, some of which is based on standard assumptions; the secondary method for methane emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

In addition to data availability, the secondary method is preferred for sources that failed a simple data-consistency screen, or "ratio test," based on the ratio of reported fuel consumption to an expected gas usage value, calculated as:

$$ratio = \frac{Q_{fuel}}{EFU} = \frac{Q_{fuel}}{MDC * \frac{t_{annual}}{HHV}}$$

where:

$ratio$ = the test value, where any ratio within a factor of 10 of matching (i.e., between 10% and 1000%) is accepted (unitless)

Q_{fuel} = the total annual amount of fuel combusted (MMscf/year)

EFU = the expected fuel usage (MMscf/year)

MDC = the reported maximum design capacity of the engine (MMBtu/hour)

t_{annual} = the annual hours of usage of the engine (hour/year)

HHV = a standardized higher heating value of the fuel, assumed to be 1,150 (Btu/scf).

A final criterion for using the primary method for methane emissions is the reported absence of emissions controls installed on the engine. Ideally, the primary method should be weighted by methane-control efficiency. However, the reported data on VOC control efficiency demonstrate substantial inconsistency, and standardized methane control ratings for engines are not readily available. So, this study assumes that any controls applied affect methane and VOCs equivalently and therefore applies our secondary method for all engines that report the presence of controls. Because the Point Source Inventory does not include information on controls, the

secondary method is used, which accounts for the possibility of emissions controls, for all engines in that inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = HP * LF * f_e * EF_{CO_2} * t_{annual}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

HP = the engine rating (hp)

LF = the load factor of the engine (unitless)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

t_{annual} = the annual hours of usage of the engine (hr/year).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{EF_{CH_4}}{EF_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

In addition to the standard assumptions described above, these methods depend on the following assumptions:

- The load factor (LF) is assumed to be 0.8 for compressor engines with an engine rating greater than 500 hp and 0.7 otherwise, based on the results of a 2005 study of compressor engines in Texas performed by the TCEQ.[153]
- The energy-basis conversion factor (f_e) for all natural gas internal combustion engines is 7858 Btu/hp-hr.[154]
- The annual hours of usage of the engine (t_{annual}) are 8,760 hr/year for engines without specific usage data, which includes all engines in the Point Source Inventory.
- Any reduction in CO_2 released from the engine related to emissions controls is negligible.

Boilers, Heaters, and Turbines

Data on boilers and heaters are obtained from the Special Inventory, and data on boilers, heaters, and turbines are obtained from the Point Source Inventory. Although turbines substantially differ from boilers and heaters, estimation of emissions follows equivalent methods for all three profiles in the Point Source Inventory. Also, although boilers and heaters can occur at both production and processing sites, they are associated with natural gas processing; therefore, boilers and heaters are assigned to the processing stage.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel. Where the volume of fuel combusted is not available, the secondary method for estimating emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

[153] Personal communication with TCEQ (TCEQ 2012)
[154] ENVIRON (2010), p.84

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Amine Units / Acid Gas Removal

AGR, such as by amine units, removes CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas. Unlike other emissions sources, the CO_2 emissions from amine units are calculated as a single, aggregated basin-wide estimate that does not depend on the number of sources in the inventories.

Specifically, the estimated emissions are estimated as follows:

$$E_{CO_2} = \left[MW_{prod} * f_{CO_2 prod} - MW_{pipe} * f_{CO_2 pipe}\right] * Q_{prod} * \frac{1lb - mole}{379.3\ scf}$$

where:

E_{CO_2} = mass of CO_2 emitted by all AGR sources in the basin annually (tonne/year)

MW_{prod} = the average molecular weight of production gas within the basin (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in the production gas (unitless)

MW_{pipe} = the molecular weight of pipeline-quality natural gas[155] (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in pipeline gas[156] (unitless)

Q_{prod} = the volume of natural gas produced within the basin annually (scf).

In contrast, methane emissions from AGR are estimated using calculation methods equivalent to those provided in that of General Leakage Sources, as previously discussed.

Dehydrators

GHG emissions from dehydrators are calculated using separate emissions factors depending on the life cycle stage of the site at which the source sites. In the Point Source Inventory, all dehydrators are all at processing sites; but in the Special Inventory, dehydrators exist at both production and processing sites. Therefore, following API (2009), this study uses an emission factor of 275.57 scf/MMscf gas processed for production sites, adjusting the CH_4 content from the 78.8 molar percentage assumed in that reference. Alternatively, if a dehydrator is identified at a processing site, this study uses an emission factor of 121.55 scf/MMscf gas processed and adjusts the molar CH_4 content from 86.8%.

[155] Set to 17.4 lb/lb-mole, as provided by EPA (1995) and used by ENVIRON (2010)

[156] Set to 0.47%, as per EPA (2011). To the extent that this value overestimates the CO_2 content in pipeline-quality gas, it underestimates CO_2 emissions from acid gas removal, and vice versa.

For those dehydrators identified as having a control present in the Special Inventory, and assuming that all dehydrators in the Point Source Inventory have emission controls, this study assumes a 98% control efficiency for methane and a 0% efficiency for CO_2. Otherwise, this study assumes 0% efficiency of control for both emissions types. The 98% efficiency assumption is supported by standard efficiency assumptions for flares, as well as a reported 97% efficiency for separator-condensers (Schievelbein 1997), an alternative method of control for dehydrators.

Primary Methods

For dehydrators at production sites:

$$E_{CH_4} = P * 0.0052859 * \left[\frac{f_{CH_4,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0052859 * \left[\frac{f_{CH_4,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * \frac{f_{CO_2,county}}{f_{CH_4,county}}$$

and for Dehydrators at Processing sites:

$$E_{CH_4} = P * 0.0023315 * \left[\frac{f_{CH_4,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0023315 * \left[\frac{f_{CH_4,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * \frac{f_{CO_2,basin}}{f_{CH_4,basin}}$$

where CE = 0.98 if controlled, 0 otherwise, and P is the volume of gas processed. Controls do not affect CO_2 emissions, which are weighted by the ratio of CO_2 to CH_4 (by weight) in the production gas, by county.

Secondary Methods

For Dehydrators without P (which includes all Point Source Inventory dehydrators), the secondary method is based on VOC emissions:

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{1-CE}\right) * \frac{f_{CO_2}}{f_{VOC}}$$

Flares

Due to a lack of sufficient information for identifying the specific source to which each flare is associated, this study identifies a flare's process stage by the type of site at which it is found and assumes that all flares combust production gas. This approach will likely overestimate natural gas process-chain emissions due to some of the flares controlling emissions from condensate and crude oil tanks, which should be omitted through co-product allocation; but the overestimation is expected to be small because total flare emissions are small. Only those that can be identified as emissions control for condensate tanks are removed; those that can be identified as combined emissions control for an included profile and condensate tanks are kept. Although this leads to a

likely overestimation of emissions from flaring, flares only account for a small proportion of overall emissions, so this overestimation is expected to be small.

For CO_2 emissions, the primary method, which depends on knowing the amount of gas combusted, treats flares equivalently to other combustion sources. The secondary method uses reported VOC emissions and an assumed 98% efficiency to back-calculate the volume of gas combusted. Methane emissions are assumed to be attributed to the original source that is controlled by the flares and therefore are neither calculated nor assigned to this profile.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = (Q_{waste} + Q_{pilot}) * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{waste} = the total annual amount of waste gas combusted (scf/year)

Q_{pilot} = the total annual amount of pilot gas combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{f_{VOC}}\right) * \left(\frac{1}{1-CE}\right) * f_C * f_O * CE$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the combusted gas by mass (unitless)

CE = the assumed control efficiency of the flare, 98% (unitless)

f_C = the fraction of carbon in the combusted gas by mass (unitless)

f_O = the fraction of combusted gas carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Loading and Tanks

For produced-water loading and produced-water tanks, GHG emissions are calculated from VOC emissions and the ratio of VOCs to GHGs in the water flash gas.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/yr)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Calculations of Gas Losses from Production and Processing

Gas Release Sources

Profiles reporting gas release sources include amine units, blowdowns, fugitives, glycol dehydrators, and vents.

Natural Gas Lost, Method 1: From Reported Vented Volume

When the volume of gas vented is listed (only for some vents in the Special Inventory), the only calculation is a simple unit conversion, as follows:

$$Q_{NG,lost} = Q_{vented} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{vented} = the total annual volume of gas emitted from the source (scf/year).

Natural Gas Lost, Method 2: From Reported VOC Emissions

For most gas leakage sources, the volume of gas released is not directly reported. For these, the volume of gas released can be calculated from the amount of VOC emissions, as follows:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{f_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{MW_{gas}}\right) * \left(\frac{379.3scf}{1.0lb-mole}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole).

Engines

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include a direct report of the volume of fuel used. But only engines report the characteristics used for the ratio test, described in the section above on compressor engine emissions, and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (only relevant for some Special Inventory sources) and passes this study's Ratio Test for data entry issues, the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/yr)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year).

Natural Gas Lost, Method 2: Using Engine Characteristics

The secondary method uses engine characteristics to estimate the amount of fuel used, which is equivalent to the natural gas lost for these sources.

$$Q_{NG,lost} = HP * LF * f_e * \frac{1}{HHV} * t_{anuual} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

HP = the engine rating (hp)

LF = the load factor of the engine (0.8 or 0.7, depending on horsepower)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

HHV = the higher heating value of the fuel (Btu/scf)

t_{annual} = the annual hours of usage of the engine (hr/year).

Non-Engine Combustion

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include direct report of the volume of fuel used. But only engines have the characteristics used both for the Ratio Test and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (which is only relevant for some Special Inventory sources), the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year)

Natural Gas Lost, Method 2: From Reported VOC Emissions

This alternative method only applies to Point Source Inventory non-engine combustion sources:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{EF_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{HHV}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{VOC} = the VOC emission factor for the source (lb/MMBtu)

HHV = the higher heating value of the fuel (Btu/scf).

Methane Lost, for All Sources: Convert from Natural Gas Lost

For all sources, the conversion from estimated natural gas lost to estimated methane lost is completed as shown:

$$Q_{CH_4,lost} = Q_{NG,lost} * \frac{MW_{gas}}{MW_{CH_4}} * f_{CH_4}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

$Q_{CH_4,lost}$ = the volume of CH_4 lost or used by the source annually (MMscf/year)

f_{CH_4} = the fraction of CH_4 in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

MW_{CH_4} = the molecular weight of CH_4 (16.0 lb/lb-mole).

Summary of Adjustments to Estimated Emissions

Emissions from production sources in the Point Source Inventory are adjusted by allocation across co-products at the county-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate, e.g.,

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb - mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g - CO_2}{12g - C}\right) * \frac{1tonne}{2204.62lb}$$

$Allocation_{county}$ = the county-level allocation of emissions across co-products.

Emissions from production sources in the Area Source Inventory are adjusted by allocation across co-products at the county level and the adjustment for changes in production volumes, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}] * [Adjustment_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{county}$ = the county-level allocation of emissions across co-products

$Adjustment_{county}$ = the county-level adjustment of emissions from 2008 to 2009 estimates.

Adjustments to emissions from production sources in the Special Inventory differ from this by (1) allocation across co-products at the site-level, rather than at the county-level, (2) requiring site-level and inventory-level corrections, and (3) not requiring the production volume adjustment, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{site}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{site}$ = the site-level allocation of emissions across co-products.

Emissions from processing sources in the Point Source Inventory are adjusted by allocation across co-products at the basin-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Finally, emissions from processing sources in the Special Inventory are adjusted by the inventory-level and site-level corrections and by allocation across co-products at the basin level, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Greenhouse Gas Emission Factors

To create emissions factors for process stages, the sum of estimated emissions for sources in each stage is divided by the production volume of gas associated with those emissions. The relevant statistics exist at the county level for production sources and at the basin level for processing sources.

For sources in the production stage, emissions and production can be associated at the county level. This emission factor focuses only on natural gas production from gas wells, omitting the

casinghead gas produced as a co-product from oil wells. Specifically, for CH_4 emissions associated with production (and where CO_2 is calculated analogously):

$$EF_{CH_4,prod,i} = \frac{\sum_{n \in N_{prod,i}} E_{CH_4,n}}{Q_{GWgas,i}}$$

where:

$EF_{CH_4,prod,i}$ = the CH_4 emission factor for production in county *i* (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source *n* annually (tonne/year)

$N_{prod,i}$ = the set of production sources in county *i*

$Q_{GWgas,i}$ = the volume of gas produced from gas wells in county *i* annually (Mcf/year).

For sources in the processing stage, however, emissions and production can only be associated at the basin level because centralized processing sites likely process Barnett Shale gas produced in neighboring counties. In addition, the gas processed by these facilities includes gas produced both from gas wells and oil wells (i.e., casinghead gas), and the denominator includes the sum of these two volumes, accordingly. Specifically, for CH_4 emissions associated with processing (and where CO_2 is calculated analogously):

$$EF_{CH_4,proc} = \frac{\sum_{n \in N_{proc}} E_{CH_4,n}}{Q_{GWgas} + Q_{Cgas}}$$

where:

$EF_{CH_4,proc}$ = the CH_4 emission factor for processing in the basin (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source *n* annually (tonne/year)

N_{proc} = the set of processing sources in the basin

Q_{GWgas} = the volume of gas-well gas produced in the basin annually (Mcf/year)

Q_{Cgas} = the volume of casinghead gas produced in the basin annually (Mcf/year).

The estimation strategy for the processing stage is exposed to a risk of leakage of production volumes both into and out of the basin, where the former corresponds to emissions caused by the processing of gas not accounted for in the basin's production statistics and the latter to gas included in the production statistics that is not accounted for in the processing emissions because such processing occurs outside the basin. The potential for bias from leakage is expected to be small because of the costs incurred in shipping unprocessed gas unnecessarily, as well as the relatively small amount of production in neighboring counties (the sum of which is only 8% the sum of gas production within the basin). Further, the potential for leakage in both directions increases the likelihood that any bias introduced by one direction of leakage will be cancelled by that in the other direction. But if not completely cancelling, the small scale of production outside the basin suggests that the sum of leakage would be out of the basin, meaning the estimates will underestimate emission factors.

From Inventory to LCA

The final estimate of life cycle GHG emissions is calculated as:

$$EF_{LifeCycle} = \left(\frac{1}{TE}\right) * \left[\frac{EF_{PreProduction}}{L_1} + \frac{EF_{Production}}{L_2} + \frac{EF_{Processing}}{L_3} + \frac{EF_{Transmission}}{L_4} + \frac{EF_{Disposal}}{L_2}\right] + EF_{Combustion} + EF_{Construction} + EF_{Decommissioning}$$

where:

$EF_{LifeCycle}$ = the emission factor for the entire life cycle (g GHG/kWh generated)

TE = the thermal efficiency of the power plant (kWh-equivalent input/kWh generated)

$EF_{PreProduction}$ = the emission factor for all pre-production processes, including completions and workovers, amortized by the lifetime EUR (g GHG/kWh-equivalent extracted)

$EF_{Production}$ = the emission factor for all production processes (g GHG/kWh-equivalent produced)

$EF_{Processing}$ = the emission factor for all gas processing processes (g GHG/kWh-equivalent processed)

$EF_{Transmission}$ = the emission factor for all processed gas transmission processes (g GHG/kWh-equivalent transmitted)

$EF_{Disposal}$ = the emission factor for all produced-water disposal processes (g GHG/kWh-equivalent produced)

$EF_{Combustion}$ = the emission factor for combustion at the power plant, based on the assumed TE (g GHG/kWh generated)

$EF_{Construction}$ = the emission factor for all power-plant construction processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

$EF_{Decommissioning}$ = the emission factor for all power-plant decommissioning processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

L_1 = a loss factor representing the portion of gas extracted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent extracted/kWh-equivalent input)

L_2 = a loss factor representing the portion of gas produced that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent produced/kWh-equivalent input)

L_3 = a loss factor representing the portion of gas processed that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent processed/kWh-equivalent input)

L_4 = a loss factor representing the portion of gas transmitted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent transmitted/kWh-equivalent input).

Using this formula, life cycle GHG emissions are estimated as shown in Table 21.

Table 21. Life Cycle GHG Emissions Values (g CO_2e/kWh,100-yr)

		Not Separated	From CO_2	From Methane	Sum Base-EUR	Sum High-EUR	Sum Low-EUR
	EUR (bcf)				1.42	4.26	0.45
Fuel Cycle	Pre-Production (non-completions)[a]		13.9		13.9	4.6	44.6
	Completions and Workovers[b]			20.2	20.2	6.7	65.0
	Production		3.3	3.0	6.3	6.3	6.3
	Processing		15.6	2.4	18.0	18.0	18.0
	Produced Water Disposal		0.0	0.7	0.7	0.7	0.7
	Transmission[c]		3.2	16.2	19.4	19.4	19.4
Power Plant	Construction and Decommissioning[d]	1.2			1.2	1.2	1.2
	Combustion at Power Plant[e]		359.0		359.0	359.0	359.0
Overall	Life Cycle	1.2	395.0	42.4	438.6	415.8	514.1

[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al., 2011).

[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and 66.2% methane by mass.

[c] Based on Skone et al. (2011)

[d] Based on Skone and James (2010)

[e] Based on Skone et al. (2011)

Appendix C: Requirements, Standards, and Reporting

Table 22. State Revisions to Oil and Gas Laws

PA	Updated regulations in 2010. Particular emphasis on well construction, disclosure, handling and disposal of recovered fluids. New 2012 legislation also created new setbacks, environmental impact analysis requirements, new fees, floodplain drilling restrictions, restoration requirements, general containment requirements, public disclosure requirements, restricted local control.
NY	Proposed major overhaul of regulations in 2011 specifically to address high-volume hydraulic fracturing. Some of the most comprehensive rules in the nation. Added new subpart 560 containing definitions specific to high-volume hydraulic fracturing, setback, reporting, well construction, and reclamation standards.
CO	Major overhaul of regulations in 2009. In 2011, revised disclosure rule, added a requirement that operators must notify Commission within 48 hours of intention to fracture and provide landowners within 500 feet of proposed oil and gas location information regarding fracturing and how to collect baseline monitoring.
WY	Updated regulations in 2010. Revised disclosure and pit requirements; strengthened presumptive Best Available Control Technology requirements for air emissions (green completions in Jonah Pinedale Anticline Area and Concentrated Development Areas).
TX	Updated air rules and implemented disclosure rule in January 2012.
LA	Finalized new disclosure rule in October 2011.

Table 23. Fracking Fluid Disclosure Requirements

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
State Code	COGCC Rule 205A	La. Admin Code. tit. 43, pt. XIX, § 118	Draft SGEIS 8.2.1.1	Act 13, §3222, 3222.1	16 Tex. Admin Code § 3.29	WOGCC Rules, Ch. 3 § 45
Takes Effect	February 1, 2012	October 20, 2011	Proposed 2011	April 16, 2012[157]	February 1, 2012	October 17, 2011
Duty to Report?	Yes. Names of products in fracking fluids, chemicals in fracking fluids, associated chemical abstract numbers.	Yes. Names of products in fracking fluid, chemical ingredients in fracking fluid, chemical concentrations of hazardous chemicals.	Yes. Fracking fluid additive products and material safety data sheets	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract service numbers.	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract numbers, volume of fracking fluid.	Yes. Names of products in fracking fluid, chemicals present in fluid, associated chemical abstract service numbers, volume of fracking fluid.
To Whom?	Yes, to Frac Focus provided public can search information by company, chemical ingredient, geographic area, and other criteria by Jan. 1, 2013. If not, COGCC will build its own searchable database. Must also provide landowners within 500 feet of the well with information regarding fracking and baseline water sampling.[158]	Office of Conservation, district manager or Frac Focus	NY Department of Environmental Conservation for public disclosure	PA Department of Environmental Protection or Frac Focus. Similar requirement to CO that Frac Focus must be searchable by Jan. 1, 2013, or DEP may require other form of public disclosure.	Yes, to Frac Focus.	Yes to WOGCC website.

[157] Note, however, that Act is enjoined pending resolution of legal challenge to its constitutionality on other grounds.
[158] 2 CCR 404-1, R. 305.e.(1).A. (2012).

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
When?	No later than 60 days after completion of fracking operation or no later than 120 days after commencement of fracking operation.	Within 20 days after operations are complete.	Prior to drilling.	Within 60 days of completion of well completion	On or before date operator submits Well Completion Report; operator must also upload required information to Disclosure Registry.	Before fracking begins (APD) and after operation is complete (Well Completion Report Form).
Trade Secret Exemption?	Yes, for chemicals but not for chemical family name.	Yes, for chemicals but not for chemical family.	Yes, but must still disclose information regarding properties and effects of hazardous chemical.	Yes, for chemicals but not for chemical family. Claims governed by PA's "Right to Know" law, which requires companies submit trade secret information to the DEP. Citizens may challenge information.	Yes, for chemicals but not for chemical family.[159]	Yes, operator can make a request to WOGCC to keep proprietary information confidential.
Trade Secret Disclosure?	Yes, trade secrets must be disclosed to medical professional in event of medical emergency, to Commission to respond to a spill, release or complaint or if needed for diagnosis or treatment of exposed individual. Disclosure must be kept confidential.	Yes, if required to be provided to a health care professional, doctor, or nurse.	Yes to health professionals, employees and designated representatives.	Yes, if required to be provided to a health care professional in event of an emergency. Disclosure must be kept confidential.	Yes, to health professionals and emergency responders to diagnose, treat, or otherwise respond to an emergency. Disclosure must be kept confidential.	No.

[159] The Texas law contains provisions that allow landowners on whose property operations are taking place, landowners with adjacent property to operations, or state departments and agencies with jurisdiction over matters relevant to trade secret information to challenge a claim of trade secret.

Table 24. Water Acquisition Requirements

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
North San Juan (Colorado)	Permit for groundwater withdrawal outside designated ground water basin.[160]	Must report total volume of water used in fracking job to Frac Focus.[161]	Local requirements apply.[162]	None.[163]
Upper Green River (Wyoming)	Yes[164]	Yes, limited to amount, not source.[165]	None identified.	None.
Marcellus (New York)	Yes[166]	Operator must identify source of water in permit and report annually on aggregate amounts withdrawn or purchased.[167]	Monitoring and other requirements to ensure no degradation to water quality and quantity.[168]	Must develop a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flow back or production fluid either to fracture other wells or for approved beneficial uses.[169]

[160] C.R.S. §§ 37-90-137, 37-92-308 (2011). See also http://cogcc.state.co.us/Library/Oil_and_Gas_Water_Sources_Fact_Sheet.pdf. The Colorado Ground Water Commission may define and alter designated groundwater basins within the state based on adequate factual information. See C.R.S. §37-90-106 (2012).
[161] COGCC R. 205A(b)(2)(A)(viii) (2012).
[162] See, for example, Archuleta County Land Use Code Section 9.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/Planning/Section%209%20-%20Mining%20December%202010.pdf.
[163] *See* Response of the Colorado Oil and Gas Conservation Commission to the STRONGER Hydraulic Fracturing Questionnaire, 32, http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf (noting that R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans that may provide for reuse of waste water. Rules 903 and 907 encourage recycling by providing for multi-well pits. R. 902.e and 903.a.(4) creates new pit classification for multi-well pits. "These pits are often centrally located in the oil or gas field, are used to store fluids from multiple wells, and may include treatment areas where fracturing flowback fluids and produced water can be brought up to specifications. COGCC is also working with several operators on waste sharing plans that will facilitate the reuse and recycling of fracturing fluids and produced water."
[164] National Conference of State Legislatures, "State Water Withdrawal Regulations," http://www.ncsl.org/issues-research/env-res/state-water-withdrawal-regulations.aspx.
[165] Conversation with Rick Marvel, engineer, WOGCC, May 29, 2012.
[166] NYSGEIS § 7.1.1.1. Withdrawal permits will include conditions to monitor and enforce water quality and quantity standards and requirements. If withdrawing from within 500 feet of wetlands, must require monitoring during pump test. Lowering groundwater levels at or below wetlands is a significant impact triggering site-specific State Environmental Quality Review Act review. Withdrawals from groundwater within 500 feet of private wells also trigger site-specific State Environmental Quality Review Act reviews.
[167] *Id*.
[168] See *Id* (discussing various standards such as passby flow requirements, water conservation practices, and protections for aquatic life that may be included by permit).
[169] NYSGEIS § 5.12.

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
Marcellus (Pennsylvania)	Cannot withdraw without approved water management plan.[170]	Report list of water sources used under approved water management plan and volume of water.[171]	Water management plan that includes plan for reuse of fluids.[172]	Water management plan must include plan for reuse of fluids used to fracture wells.[173] Well completion report must include total volume of water recycled.[174]
Haynesville (Louisiana)	None identified.	Must report water source and volumes after completion or recompletion.[175]	None.	Regulations recognize processing of E&P waste into reusable materials as alternative to other means of disposal and authorizes commercial facilities for the purpose of generating reusable material.[176]
Eagle Ford (Texas)	Yes.[177]	Report total volume of water used in fracking to Frac Focus.[178]	None identified.	None.
Barnett (Texas)	Yes.	Report total volume of water used in fracking to Frac Focus.[179]	None identified.	None.

[170] 58 PA Con. Stat. ch. 32, § 3211(m). Condition of all permits to hydraulically fracture natural gas wells in unconventional formations.
[171] *Id*. § 3222(b.1)(1)(vi) (2012).
[172] 58 PA Con. Stat. ch. 32, § 3211(m). Operators must develop water management plan, which must be approved by DEP, governing withdrawals or use of water. Approval of plan is contingent on determination that withdrawal/use will not adversely affect quantity or quality of water, will protect and maintain designated and existing uses of water supply, will not cause adverse impact to water quality in watershed and will include a reuse plan for fluids for hydraulically fractured wells. If plan is operated in accord with conditions established by the Susquehanna River Basin Commission, the Delaware River Basin Commission or the Great Lakes Commission, it is presumed to meet above conditions.
[173] 58 PA Con. Stat. ch. 32, §. 3211(m)(2)(iv).
[174] *Id.* § 3222(b.1)(1)(vi) (2012).
[175] Well History and Work Resume Report, Form WH-1, Louisiana Hydraulic Fracturing State Review, 5 (March 2011), http://www.strongerinc.org/documents/Final%20Louisiana%20HF%20Review%203-2011.pdf.
[176] La. Admin. Code tit. 43:XIX, § 565 (2010).
[177] Tex. Water Code, tit. 2, ch. 11. *See also* http://www.rrc.state.tx.us/barnettshale/wateruse.php Short-term permits issued by Texas Commission on Environmental Quality Regional Offices and permits for more than 10 acre-feet of water or for a term lasting more than 1 year are issued by the Commission's Water Rights Permitting Team.
[178] 16 Tex. Admin. Code § 3.29(c)(2)(A)(viii) (2011).
[179] *Id*.

Table 25. Well Construction Standards

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Federal Lands[180]	Yes.	None.	Yes. Mechanical integrity test required before each well stimulation operation.	No. But must continuously monitor and record pressure during well stimulation and notify if annulus pressure increases by more than 500 lbs per square inch.
North San Juan (Colorado)	Yes. Required on all production casing, or in the case of production liner, the intermediate casing.[181]	None specified in rules, but OGCC requires casing be set at least 50 feet below aquifer to ground surface.	Yes. Must test production casing during completion and production.[182]	Must monitor and record bradenhead annulus pressure during fracking and notify COGCC of conditions indicating fracking fluids have escaped producing reservoir.[183]
Upper Green River (Wyoming)	No specific requirement.[184]	None specified but casing must be run below known or reasonably estimated utilizable fresh water levels.[185]	No. Mechanical integrity tests may be required but not mandatory.[186]	No
Barnett (Texas)	No.	None specified but all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm.[187]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to max. pressure to which pipe will be subjected in the well	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[188]

[180] BLM (2012). "Proposed Rule: Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands," Department of Interior, May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.
[181] COGCC R. 317(o).
[182] *Id*. at 317(j).
[183] *Id*. at 341.
[184] WOGCC Rules, ch. 3, §§ 12, 21, requires submission of well logs, which includes "electrical, radioactive, or other similar log runs," which may, but does not necessarily, include cement bond logs.
[185] *Id.* § 22(a)(i).
[186] *Id.* § 45.
[187] 16 Tex. Admin. Code § 3.13.
[188] *Id.* § 3.17.

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Eagle Ford (Texas)	No.	None specified but all usable-quality water zones must be isolated and sealed off to effectively prevent contamination or harm.[189]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which pipe will be subjected in the well.	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[190]
Haynesville (Louisiana)	Yes, operator must run cement bond log, temperature survey, X-ray log, density log, or other acceptable test.[191]	None.[192]	Surface, intermediate, and producing casing must be tested depending on their depth.[193]	No.
Marcellus (New York)	Department may require a cement bond long or other measures to ensure adequacy of the bond.[194]	Must be set to at least 75 feet beyond deepest fresh water zone or bedrock, whichever is deeper.	No.[195]	No.
Marcellus (Pennsylvania)	In response to a potential natural gas migration incident, the department may require operator to evaluate adjacent oil and gas wells with different measures, including cement bond logs.[196]	Must be set 50 feet below deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper.[197]	Yes. New casing must have an internal pressure rating that is at least 20% greater than anticipated maximum pressure to which casing will be exposed. Used casing must be pressure tested after cementing and before continuation of drilling.[198]	No.

[189] *Id.* § 3.13.
[190] *Id.* § 3.17.
[191] La. Admin. Code, tit. 43, pt. XIX, §419(A)(3).
[192] *Id*. § 109.
[193] *Id*.
[194] N.Y. Comp. Codes R. & Regs. tit. 6, ch. V, §559.6(d)(2).
[195] *Id*. § 557.2.
[196] 25 Pa. Code § 78.89.
[197] *Id*. § 78.83.
[198] *Id*. § 78.84.

Table 26. Baseline Monitoring Requirements

Play/Basin	Requirement
North San Juan (Colorado)	Operators drilling within 301–2,640 feet of surface water intended to be used for drinking water must collect baseline water samples from the surface water prior to drilling and 3 months after the conclusion of drilling or completion.[199] Operators must collect water well samples from nearby wells prior to drilling, as well as 1, 3, and 6 years after completion.[200] Operators must provide landowners within 500 feet of proposed oil and gas location with instruction as to how to collect baseline water samples.[201]
Marcellus (New York)	Operator must make reasonable attempt to sample and test all residential water wells within 1,000 feet of a wellpad; must be sampled prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the DEC.[202]
Marcellus (Pennsylvania)	PA law provides for a rebuttable presumption that a well operator is responsible for pollution of a private or public water supply if the supply is within 2,500 feet of an unconventional well and the pollution occurred within 12 months of the later of the completion, drilling, stimulation or alteration of the well. Operators can overcome this presumption by undertaking a pre-drilling or pre-alteration survey that demonstrates pre-existing contamination or if landowner or water purveyor refuses to allow the operator to test.[203]

[199] 2 Colo. Code Regs. § 404-1; COGCC R. 317B(d)(e). Samples must be tested for BTEX, TDS, metals, and other specified parameters in the rules.
[200] Various Commission Orders. *See* COGCC Response to STRONGER, 4, available at http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf. R. 608 extends the requirements set forth in Commission Orders to other parts of the state with CBM wells and requires operators to identify all plugged and abandoned wells within ¼ mile of proposed CBM well, assess the risk of leaking gas or water, make a reasonable good-faith effort to conduct pre-production soil gas survey of all plugged and abandoned wells within ¼ mile of proposed CBM well and post-production survey 1 and every 3 years after production has commenced, and sample water wells located within ¼ or ½ mile from proposed CBM well and within 1, 3, and 6 years thereafter.
[201] 2 Colo. Code Regs. § 404-1; COGCC R. 305.e.(1).A. (2012).
[202] N .Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).
[203] 58 Pa. Cons. Stat § 3218(c).

Table 27. Closed-Loop or Pitless Drilling Requirements

Play/Basin	Requirement	Date Adopted
North San Juan (Colorado)	Pitless drilling within 301–500 feet of surface water intended to be used for drinking water. Pitless drilling or containment of all flowback and stimulation fluids in liner pits within 501–2,640 feet of surface water intended to be used for drinking water unless operator can demonstrate pit will not adversely affect waters.[204]	2008
Upper Green River (Wyoming)	Closed system required where groundwater is less than 20 feet below surface.[205]	2010
Marcellus (New York)	Closed-loop tank system for drilling fluids and cuttings produced from horizontal drilling unless an acid rock drainage mitigation plan for on-site burial of such cuttings is approved by department.[206] Cuttings contaminated with oil-based mud or polymer-based mud must be contained and managed in a closed-loop tank system.[207]	Proposed 2011
Marcellus (Pennsylvania)	Prohibits storage and disposal of production fluids and brine in pits unless permitted under Clean Streams Law.[208]	2010
Barnett (Texas)	Closed-loop mud system required for all drilling and reworking operations unless operations located on open space of at least 25 acres and not within 1,000 feet of residence or certain public places.[209]	2009

[204] COGCC R. 317B(d)(1), (e)(1); R. 904. Colorado does not define pitless drilling. The definition of *pit* is a "natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils." COGCC R. 100.

[205] WY ADC Oil Gen. ch. 4, § 1(u). Commission has authority to require closed system in other instances to protect surface and ground water, human beings, wildlife and livestock. *Id*. Closed system "includes, but is not limited to, the use of a combination of solids control equipment (e.g., unconventional shakers, flow line cleaners, desanders, desilters, mud cleaners, centrifuges, agitators, and necessary pumps and piping) incorporated in a series on the rig's steel mud tanks, or a self-contained unit that eliminates the need for a reserve pit for the purpose of dumping and dilution of drilling fluids for the removal of entrained drilling solids. A closed system for the purpose of the Commission's rules does not automatically include the use of a small pit, even to receive cuttings." WY ADC Oil Gen. ch.1, § 2(k).

[206] NY Dept. of Envtl Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.6. Closed-loop drilling system means a pitless drilling system where all drilling fluids and cuttings are contained at the surface within piping, separation equipment and tanks. 6 N.Y. Comp. Codes R. & Regs. § 750-3.2.

[207] New York Department of Environmental Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.7.

[208] PA Office of Oil and Gas Mgmt. Rules, ch. 78.57.

[209] Fort Worth, Tex. Ordinance, § 15-42(A)(3), (A)(38)(b) (2009).

Table 28. Produced Water Disposal

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
CO	Yes, if water meets criteria for wildlife or agricultural propagation. CBM discharges via permit.[210]	Yes	Yes	Yes	Yes, water must meet state water-quality standard for agricultural/livestock use.[211]	Encouraged[212]
WY	Yes, if water meets criteria for wildlife or livestock watering or other agricultural uses.[213]	Yes	Yes	Yes	Yes, with permission.[214]	Encouraged[215]
TX	Yes[216]	No[217]	Yes	Yes, with permit.[218]	No[219]	No provisions
PA	No	Yes, for new and expanded discharges meeting standards.	Yes	Yes	Yes[220]	Yes[221]
NY	No	Yes operator must analyze POTW capacity and create contingency plan if the primary wastewater disposal is at POTW.	Yes[222]	No	Only with permission.[223]	Encouraged[224]

[210] Colorado follows national effluent limitations. 2 Colo. Code Regs. §404-1; COGCC R. 907.
[211] 2 Colo. Code Regs. §404-1, COGCC R. 907. Standard is 3,500 mg/l.
[212] No specific requirements but COGCC R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans which may provide for reuse of waste water, see http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf
[213] WY Water Quality Rules & Regs, ch. 2, appendix H. *See also* WOGCC Rules, ch. 4 §1 (ee).
[214] WOGCC Rules, ch. 4 §1 (mm)
[215] *Id.* § 1(z). No specific requirements although "Commission encourages the recycling of drilling fluids and by administrative action approves the transfer of drilling fluids intended for recycling.
[216] Personal communication with John Becker, Texas Railroad Commission.
[217] Based on conversation with Phillip Urbany, engineer, TX Commission on Environmental Quality, May 29, 2012.
[218] 16 Tex. Admin. Code §3.8(d)(2).
[219] Our research did not identify any prohibition on land application but also no clear authorization.
[220] 25 Pa. Code §78.63.
[221] AB 13, Sec. 3211(m).

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
LA	No[225]	Discharge to a POTW is not a permissible disposal method for produced water in Louisiana.[226]	Yes	Yes	Yes[227]	No provisions

[222] N.Y. Comp. Codes R. & Regs. tit. 6, §750-1.24. *See also* 40 C.F.R. 144 & 146.
[223] Revised SGEIS at 7-60: Those wanting to road spread production brine must petition for a beneficial use determination. NORM concentrations in Marcellus Shale likely won't allow road spreading of brine, but "[a]s more data becomes available, it is anticipated that petitions for such use will be evaluated by the Department."
[224] Proposed N.Y. Comp. Codes R. & Regs., tit. 6, §560.7. Removed pit fluids must be disposed, recycled or reused as described in approved fluid disposal plan. Operator must submit fluid disposal plan (see regs at 750. 3.12).
[225] EPA National effluent limitation, *see* 40 CFR ch. I, subch. N; see also http://www.deq.louisiana.gov/portal/Portals/0/planning/Permits%20Docs/Timeline022912mcm-Version%204.pdf (discharges prohibited onto vegetated areas, soil, intermittently exposed sediment surface, lakes, rivers, streams, bayous, canals, or other surface waters regionally characterized as upland, freshwater swamps, freshwater marshes, natural or manmade water bodies bounded by freshwater swamp/marsh).
[226] *See* La. Admin Code titl. 43, pt. XIX, §313.
[227] *Id*. §313(D).

Table 29. Green Completion Requirements

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Federal[228]	Hydraulically fractured gas production wells must capture and route all saleable gas to a sales line during flowback starting in 2015. Exception for low-pressure wells. Does not apply to exploratory or delineation wells.	Pit flaring allowed until 2015 and thereafter allowed for non-recoverable gas. Venting allowed where flaring presents safety hazard or if flowback is noncombustible.	N/A
North San Juan (Colorado)[229]	Must use green completion practices to route saleable gas to sales line as soon as practicable. Does not apply to low-pressure or wells with less than 500 MCFD of naturally flowing gas. Exception for exploratory wells and wells not sufficiently proximate to sales lines.	Gaseous phase of non-flammable effluent may be flared or vented until flammable gas is encountered for safety reasons. During upset conditions. If variance granted.	Cannot vent or flare well directly to atmosphere without first going to separation equipment or portable tank.[230]
Upper Green River (Wyoming)[231]	Must eliminate VOCs and hazardous air pollutants to the extent practicable by routing liquids to tanks and gas to sales line or collection system. Does not apply to exploratory wells.	Permitted when required by specific operational events or circumstances.	None

[228] U.S. EPA, Final Rule, Oil and Natural Gas Sector: "New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," (2012).
[229] COGCC R. 805(b)(3).
[230] Archuleta County Land Use Code Sec. 9.2.6.3: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentView.aspx?DID=295.
[231] Wyoming Oil and Gas Production Facilities, ch. 6, § 2 Permitting Guidance (March 2010), http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf.

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Barnett (Texas)	None	N/A	All wells that have a sales line must use techniques or methods that minimize the release of natural gas and vapors to the environment during flowback except wells permitted prior to July 1, 2009, or the first well on a pad site.[232]
Marcellus (New York) *– Proposed*	REC whenever sales line available.[233]	Yes, if no sales line available.	None identified

[232] Fort Worth, Tex., Ordinance No. 18449-02-2009, § 15-42(A)(28).
[233] Proposed mitigation requirement via permit condition. New York Department of Environmental Compliance, Revised Draft SGEIS, §7.6.8.

Table 30. Setback Requirements

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
Barnett (Texas)	200 feet[234]	None	None	600 feet from home, 200 feet to fresh water well[235]	Yes
Eagle Ford (Texas)	200 feet	None	None	500 feet from home,[236] 200 feet from home[237]	Yes
Haynesville (Louisiana)	500 feet[238]	None	None	None	No
Marcellus (Pennsylvania)	500 feet[239]	500 feet[240]	1,000 feet[241]	200 feet from home or water well[242]	Yes, under current law[243]
Marcellus (New York)	None	500 feet[244]	500 feet[245]	N/A[246]	Yes, in that localities have banned development altogether, and if the state moratorium is lifted, it seems likely localities will attempt to regulate this area

[234] Tex. Local Gov't Code 253.005(c).
[235] Fort Worth, Tex.; Ordinance No. 18449-02-2009.
[236] City of Burleson, Tex., Ordinance B-790-09.
[237] Fayette County, Tex., Ordinance. Local zoning ordinance provides for the same 200-foot setback limit from residential homes but ordinance notes "Zoning Hearing Board may attach additional conditions to protect the public's health, safety, and welfare, including increased setbacks."
[238] State of La. Office of Conservation, Order No. U-HS (Aug. 1, 2009),http://dnr.louisiana.gov/assets/docs/news/2009/U-HS.pdf. *See also Louisiana Hydraulic Fracturing State Review,* (Mar. 2011), 5.
[239] Act 13, § 3215(a) (Unconventional wells cannot be drilled within 500 ft. of building or water well, without the consent of the owner of the building or well).
[240] *Id*. DEP shall grant a variance from specified setback requirements if the restriction deprives the owner of the oil and gas rights of the right to produce or share in the oil or gas underlying the surface tract. Note, the statute also provides for a 300-foot setback from streams, springs, other bodies of water identified on a U.S. Geological Survey map, or wetlands, although these "shall" also be waived upon submission of a plan containing additional measures to protect waters. *Id*. § 3215(b).
[241] *Id*.
[242] South Franklin Township, Pa.; Ordinance No. 4-2008 (Wells may not be drilled within 200 feet from an existing habitable structure or existing water well without express written consent of the owner).
[243] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to Pennsylvania municipalities and planning code and Flood Plain Management Act. However, implementation of this provision of the law has been enjoined pending resolution of a legal challenge brought by a number of local governments.
[244] Proposed 6 N.Y. Comp. Codes R. & Regs. 560.4(a)(1) (Well pad must be at least 500 ft. from a private water well unless waived by water well owner).
[245] *Id*. at 560.4(a)(2) (Well pads may not be located within 500 feet of the boundary of a primary aquifer). In addition, NY prohibits well pads within a primary aquifer, 100-year floodplain, and within 2,000 ft. of any public

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
North San Juan (Colorado)	150 feet[247]	None	Buffer Zones to protect surface water intended for drinking water	450 from home without consent[248]	Yes
Upper Green River (Wyoming)	350 feet[249]	None	None	None	No

water supply well, reservoir, natural lake or man-made impoundment except those constructed for fresh water storage associated with hydraulic fracturing, and river or stream intakes. *Id.* at 560.4(a)(2)-(4).

[246] Our research did not identify any local laws directly regulating unconventional gas development in NY.

[247] COGCC R. 603(a). In high-density areas, wellheads must be at least 350 ft. from buildings. *Id*. at 603.e(2).

[248] Chapter 90 – La Plata County's Oil and Gas regulations, § 90-122: http://co.laplata.co.us/sites/default/files/departments/planning/chapter_90_adopted_12_7_2010.pdf ; Archuleta County Land Use Code Section 9.2.6.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentCenter/Home/View/295.

[249] Pits, wellheads, pumping units, tanks and treaters shall be located no closer than 350 ft. from designated public places. Supervisor may extend setbacks or grant exceptions for good cause. WY ADC Oil Gen. ch. 3, § 22(b).

Appendix D: Risk Factor Data

This appendix provides more detailed information on the six selected shale plays considered in this study. For each play, where data are available, we provide 1) an overview of the shale play geology and resource potential, 2) trend data on the number of wells being drilled, 3) information about water usage per well, 4) information on produced water volumes and wastewater management practices, 5) issues associated with freshwater acquisition, and 6) reported data on violations. In addition, this appendix provides more information about the severity index used for water violations (D.7).

Marcellus Shale Play, Pennsylvania

Overview

The Marcellus Shale formation extends across 600 miles within four states, covering an area of about 54,000 square miles. The thickness of the formation varies, but is typically thicker in the east (up to 250 feet) and thins toward the west (Sumi 2008). The Marcellus Shale is the middle Devonian layer between the upper Middle Devonian Mahantango and underlying Middle Devonian Onodaga Limestone formation (USGS 2011). Estimates of the total economically recoverable natural gas in the basin have changed significantly over the years—from an initial estimate of 1.9 trillion cubic feet (Tcf) in 2002 to 168–516 Tcf in 2008 (UM 2010). The U.S. Geological Survey recently estimated mean undiscovered resources for natural gas liquids of 3,379 million barrels and for natural gas of 84,198 billion cubic feet (USGS 2011).

Figure 63 shows the extent and approximate depth of the Macellus formation, which underlies New York, Pennsylvania, Maryland, West Virginia, and Ohio.

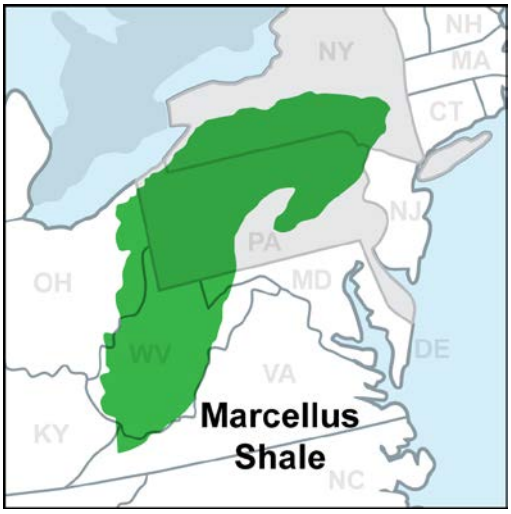


Figure 63. Extent of Marcellus Shale

Number of Wells

As of December 15, 2011, the Marcellus Shale Basin had 88 active operators. More than 9,600 permits have been submitted, with 9,328 issued. Only 36 permits have been denied since 2005 (PA DEP 2011a).The operators with the most permits in the Marcellus Shale include Chesapeake

Appalachia LLC with 1,614 drilling permits, Range Resources Appalachia LLC with 917 permits, and Talisman Energy USA Inc., with 896 permits (PA DEP 2012e).

However, the number of permits does not necessarily reflect the number of wells drilled. Only 44% of the permits resulted in a drilled well (PA DEP 2011b). Figure 64 shows the total number of permits vs. wells drilled in 2010. Figure 65 shows the total number of wells drilled in 2011.

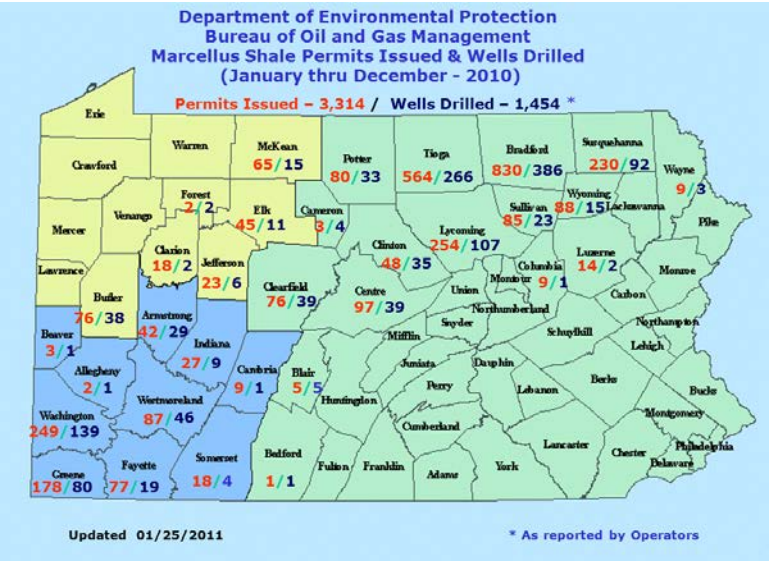


Figure 64. Marcellus Shale permits issued vs. number of wells drilled (PA DEP 2011b)

Water Usage per Well

Some 102 wells in the Marcellus Shale of Pennsylvania were randomly selected for an analysis of water usage per well. The total volume of water per well was acquired through fracfocus.org, and all other information (e.g., latitude, longitude, spud date) was gathered from the fractracker.com data set, "All Wells Marcellus," a compilation of data from the Pennsylvania Department of Environmental Protection (DEP). API numbers and well location files were cross checked between the fractracker and fracfocus data sets. Reporting to fracfocus is voluntary, causing some data to not match official API numbers and latitude/longitude found in regulated DEP data. If discrepancies occurred, then fracfocus data were discarded and a new well was chosen. Table 31 shows results for the 102 wells in Pennsylvania.

Table 31. Analysis of Water Usage per Well (gallons) for 102 Marcellus Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
4,842,070	9,548,784	430,584	9,118,200	1,690,457
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,567,320	5,802,941	3,912,996	1,889,945	0.4422

As seen in Table 31, the average volume per well was about 4,842,000 gallons. It is important to note the large range of values—with a minimum of 430,584 gallons and a maximum of 9,548,784 gallons. A histogram (Figure 66) displaying the total volume of water was created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

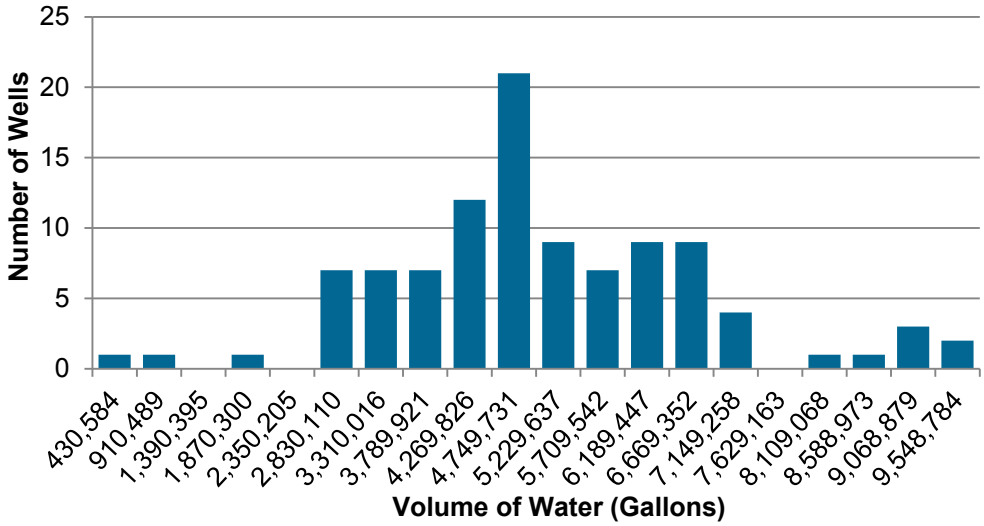


Figure 66. Histogram for 100 wells of total volumes (gallons) (fracfocus.org)

Table 32. Average Water Volume per Well by Well Type (gallons) (fracfocus.org)

Well Type	Vertical	Horizontal
Average	5,431,035	4,756,042
Sample Size	13	89

The effect of a small sample size can be seen in the comparison of average water used by type in vertical and horizontal wells in Table 32. In general, horizontal wells use much more water than vertical wells—a vertical well typically uses 0.5 to 1 million gallons of water, whereas a horizontal well uses between 4 to 8 million gallons of water (Natural Gas 2010). Further data collection is needed to provide a better comparison of vertical and horizontal wells.

Produced Water

The DEP has official production and waste reporting data on its Oil and Gas Reporting website (PA DEP 2012b). The website contains statewide data that can be downloaded on production and waste on a yearly basis. Each waste data set contains the total waste for each well per year, with the waste described by quantity, waste type, and disposal method. Before 2010, waste reports were not well organized, and an online reporting system had not yet been created, causing many wells to be excluded from the data sets. Furthermore, a server malfunction caused the loss of any relevant 2007 data. Since 2010, all waste produced by all wells in Pennsylvania have been

accurately reported. However, reporting period dates have changed to biannual, rather than annual.

Brine production and fracking fluid flowback were analyzed. Although the DEP does not have an official definition of flowback and brine, flowback can be considered the water produced before the well is put into production on a gas line.

For our analysis, natural gas wells in the Marcellus Basin were filtered out from DEP data. We observed that portions of a well's waste were reported multiple times if the waste was taken to more than one treatment facility. The duplicate data were removed from the analysis.

Brine and fracking fluid wastes were divided and analyzed separately. The results can be seen in Tables 33 and 34, along with Figures 67 and 68, with all units in gallons.

Table 33. Summary of Brine Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	14	160.4	14.2	124.9	0	30.6	0	0	4.8	0
2008	204	50,211.0	246.1	1,345.1	775.9	40,067.1	3,457.8	4,501.9	63.0	0
2009	445	231,316.3	519.7	169,860.5	4,707.5	36,402.4	16,466.8	3,875.8	3.1	0
July 2010-June 2011	1,614	287,088.1	177.8	123,623.9	35,541.3	2,711.6	19,931.4	105,248.4	7.8	23.3

Table 34. Summary of Fracking Fluid Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	2	255.4	127.7	255.4	0	0	0	0	0	0
2008	106	46,881.9	442.3	8,792.4	0	25,238.7	11,717.3	1,133.3	0	0
2009	225	105,869.6	470.5	24,505.2	610.2	46,570.4	26,371.2	7,812.4	0	0
July 2010-June2011	1,128	249,336.3	221.0	110,377.0	945.1	284.9	646.1	137,009.5	138.1	73.4

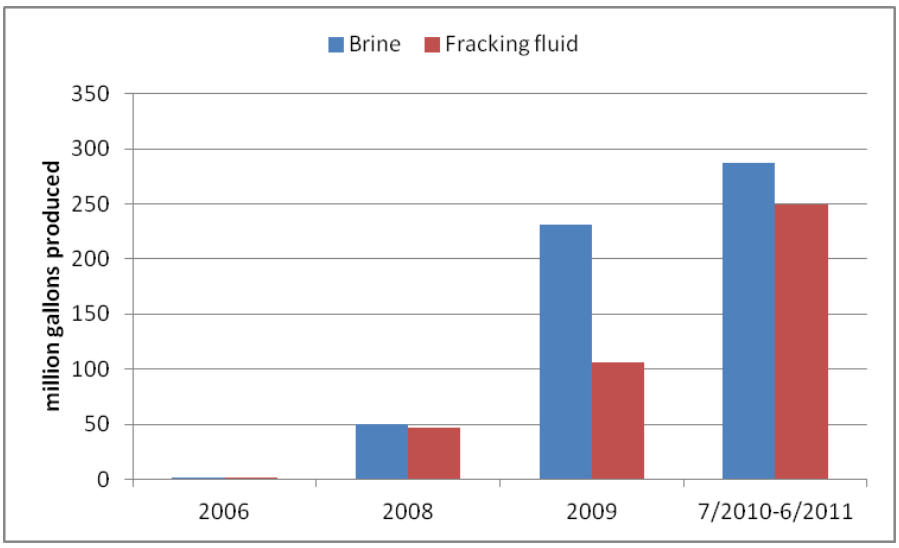


Figure 67. Total volume of produced water, 2006–2011 (PA DEP 2012b)

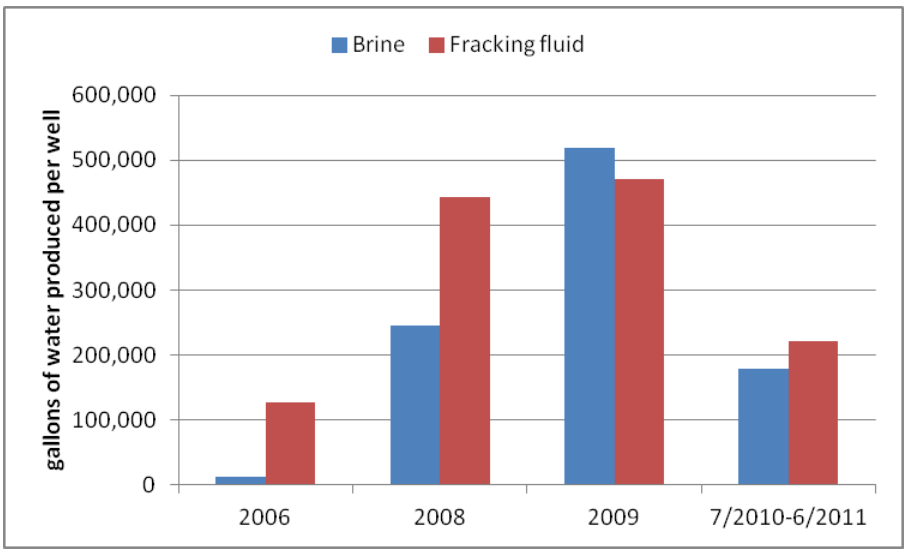


Figure 68. Average volume of produced water per well, 2006–2011 (PA DEP 2012b)

Based on Figure 67, the quantity of both produced brine and fracking fluid are clearly increasing each year—due to the increasing number of wells drilled each year. The final reporting period (July 2010–June 2011) had 1,614 wells producing brine, which is 1,169 more wells than the 2009 period (PA DEP 2012b). As seen in Figure 68, the increase in total brine and fracking fluid does not correlate with average produced brine and fracking fluid per well. There is no recognizable trend in produced water per well, as 2009 had a higher average than any other year.

Water Acquisition

Water withdrawal permit information for the Marcellus in this study focused on the Susquehanna River Basin (SRB). The Marcellus formation underlies 72% of the SRB, covering most of Pennsylvania and part of New York (Arthur 2010). The Susquehanna River Basin Commission

(SRBC) has been the forerunner in determining water usage regulations, monitoring, and permits. The SRBC actively regulates water withdrawal by oil and gas operators; all water withdrawal outside of the SRB is regulated by the DEP.

SRBC issues a report on all approved water sources for natural gas development in the SRB (SRBC 2012a). These permits include the fresh-water source, as well as the maximum allowed uptake per day. These uptakes are rarely at capacity and, according to the SRBC, many sources are used for redundancy due to passby flow conditions when water levels are low (SRBC, 2012a). It is possible to source where operators obtain their water. For example, SWEPI, LP has three different public water suppliers in three different counties. Public water supply does not have a maximum allowed daily uptake, whereas all other supplies do. SWEPI only has one docket approval for a fresh-water source—the Allegheny River in Warren County. This permit allows up to 3 million gallons per day (mgd) of water to be used. SWEPI sources the rest of its water from other drilling companies who share their water permits. Overall, SWEPI has eight different water sources, ranging from 0.217 to 3 mgd. Additional information is available regarding percentage of ground-water to surface-water permits and amounts of water used (SRBC 2011a).

Cost of Acquisition

Fees are associated with fresh-water withdrawal permits. The schedule includes a breakdown of a tiered fee system based on withdrawal amount, as well as consumptive vs. non-consumptive use (SRBC 2011a). Consumptive use is defined in 18 CFR § 806.3 as, "The loss of water transferred through a manmade conveyance system or any integral part thereof… injection of water or wastewater into a subsurface formation from which it would not reasonably be available for future use in the basin, diversion from the basin, or any other process by which the water is not returned to the waters of the basin undiminished in quantity (e-CFR 2012)."

On a per gallon basis, the SRBC fees range from $0.00685–0.1425/gallon for consumptive use, and $0.0030–0.07475/gallon for non-consumptive withdrawals (SRBC 2011a).

Considering SWEPI, LP, it can be seen that a typical docket of 0.250 mgd of surface water would cost $9,975 if the water was not used consumptively. If the use is consumptive, then $1,000 is added as an annual compliance and monitoring fee. There will also be a consumptive-use mitigation fee if the company wishes to use the fee as a method of compliance with 18 CFR §806.22(b). This section states that during low flow periods, several steps may be taken to mitigate consumptive use. One option is to reduce water withdrawal from a source equal to the consumptive use of the operator. Another option is to take water from another approved source. If these or the other provided options are not chosen, the company may choose to pay a fee of $0.29 per 1,000 gallons of water consumed. In the case of SWEPI, this may be an additional cost of $72.50. Companies pay for metering systems and report to the SRBC on a daily basis for each well on its water use.

Another source of fresh water is public supply. The cost of this source varies from utility to utility, but most rates can be found on utility websites. Rates vary significantly from supplier to supplier, and oftentimes unique deals are made between supplier and operator. The deal between East Resources Management, LLC and Morningside Heights Water District approves up to 400,000 gallons per day at a rate of $0.0145 per gallon (Pressconnects 2010). This is 60% greater

than water supplier P.A. American Water, which charges $0.008979 per gallon (American Water 2012).

The above costs refer to obtaining water and do not cover the price of transporting the water. Most water is transported by either pumping or trucking. PSU estimates average trucking costs of $0.2 per gallon (Pressconnects 2010). Further analysis of water-supply distances to wells would need to be studied using GIS to assess the actual cost of water transportation.

Violations

The majority of the violations reported from 2009–2011 fall under the category of "minor - no effect" (Figure 69 and Table 35) (NEPA 2012). "Procedural" violations account for about 20%, and "minor effect" and "substantial" account for about 10%. Also, it should be noted that there are no "major" violations. This data set includes all of the violations from 2009–2011 (NEPA 2012). Further information on violations can be found in D.7 of this appendix.

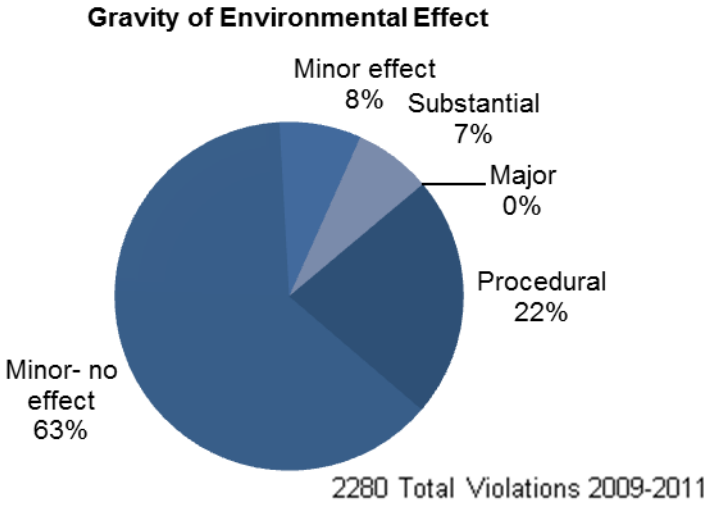


Figure 69. Pennsylvania violations (NEPA 2012)

Table 35. Pennsylvania Violations (NEPA 2012)

Procedural	510	22.4%
Minor - no effect	1433	62.9%
Minor effect	173	7.6%
Substantial	164	7.2%
Major	0	0.0%
Total	2280	

Barnett Shale Play, Texas

Overview

In the early 1900s, geological mapping noted a thick, black, organic-rich shale in an outcrop near the Barnett stream (TRRC 2012e). The Barnett Shale formation exists under extensive areas in Texas and crops out on the flanks of the Llano Uplift, 150 miles to the south of the core area (Figure 70). Current boundaries of the formation are due primarily to erosion (TDWB 2007). The Fort Worth Basin is bounded by tectonic features to the east—notably, the Ouachita Overthrust, an eroded, buried mountain range—and to the north by the uplifted Muenster and Red River Arches. The Barnett Shale dips gently toward the core area and the Muenster Arch from the south where it crops out and thins considerably to the west; its base reaches a maximum depth of ~8,500 ft (subsea) in the northeast. The depth to the top of the Barnett ranges from ~4,500 ft in northwestern Jack County, to ~2,500 ft in southwest Palo Pinto County, to ~3,500 ft in northern Hamilton County, to ~6,000 ft in western McLennan County, to ~7,000 to 8,000 ft in the Dallas-Fort Worth area. Further west in Throckmorton, Shackelford, and Callahan Counties, the depth to the Barnett ranges between ~4,000 and 2,000 ft (TDWB 2007).

The U.S. Geological Survey (USGS) estimated the mean gas resources at 26.7 Tcf (USGS 2004).

Figure 70. Extent of Barnett Shale

Figure 70 shows the extent of the Barnett Shale in Texas. The formation is actually considered to be a hydrocarbon source, reservoir, and trap, all at the same time. As a reservoir, it is known as a "tight" gas reservoir, indicating that the gas is not easily extracted. However, hydraulic fracturing technology has made it possible to extract the gas (TRRC, 2012d). For the Barnett Shale, permeability ranges from microdarcies to nanodarcies, porosity ranges from 0.5% to 6%, and water saturation is below 50%.

Future development will be hampered, in part, because major portions of the field are in urban areas, including the rapidly growing Dallas-Fort Worth Metroplex. Some local governments are researching means by which they can drill on existing public land (e.g., parks) without disrupting

other activities so they may obtain royalties on any minerals found. Others are seeking compensation from drilling companies for roads damaged by overweight vehicles, because many of the roads are rural and not designed for use by heavy equipment. In addition, drilling and exploration have generated significant controversy (TRRC, 2012d).

Number of Wells

The Barnett Shale has experienced substantial development over the last decade, as evidenced by the number of wells (Figure 71) and estimates of total gas production (Figure 72).

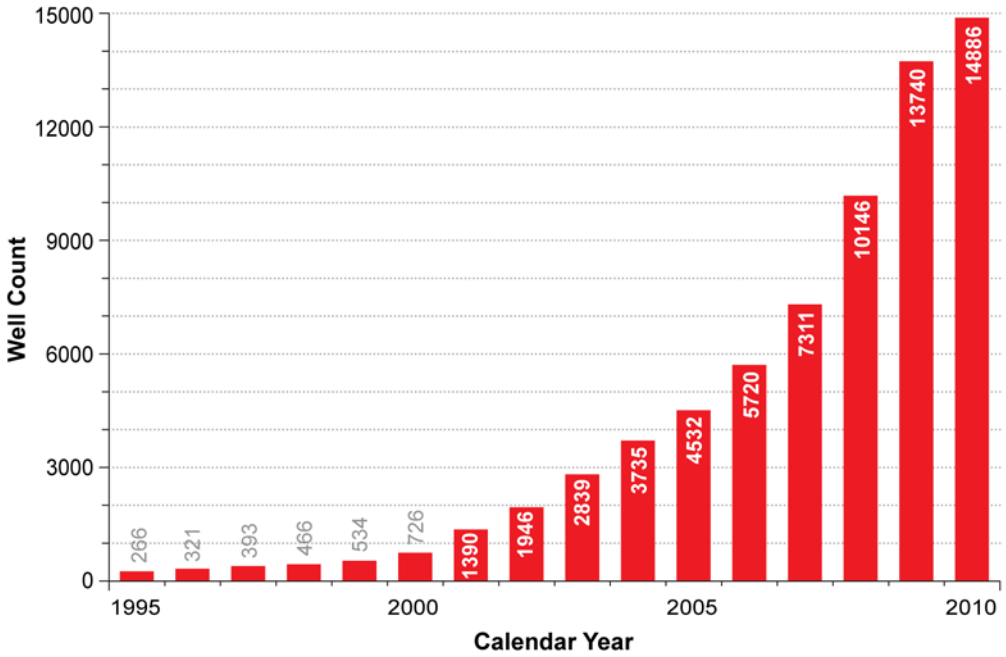


Figure 71. Wells in Barnett Shale, 1995-2010 (TRRC, 2012c)

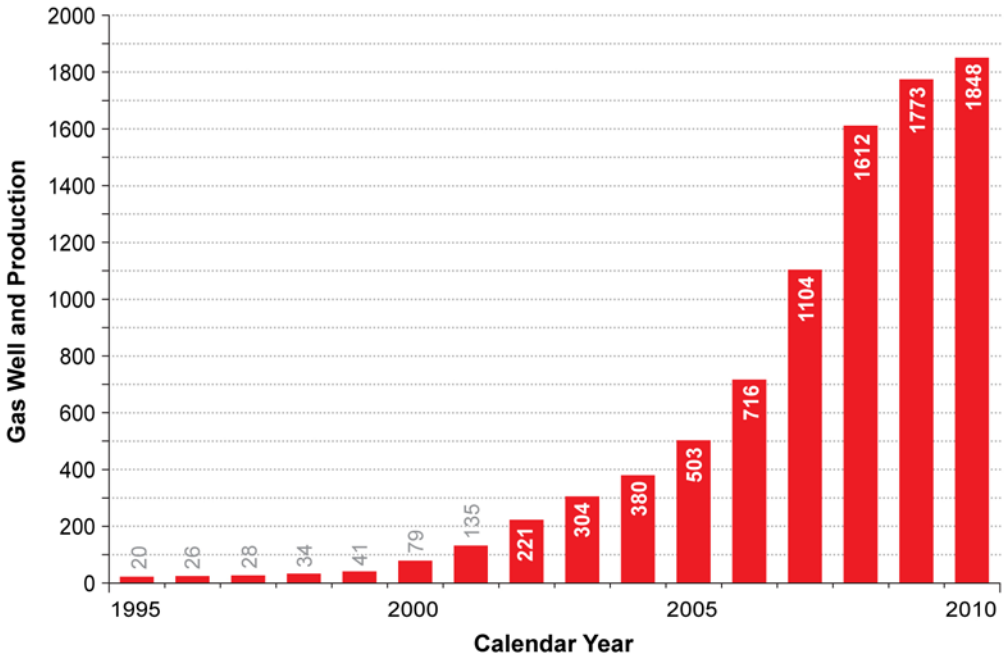


Figure 72. Gas production in the Barnett Shale (bcf), 1995-2010 (TRRC, 2012e)

Water Usage per Well

Table 36 shows the analysis results on 100 Barnett Shale wells selected randomly from fracfocus.org.

Table 36. Statistics of Water Use (Gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
2,537,853.848	26,315,125	29,186	26,285,939	3,512,472.559
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
1,293,306	4,298,286	86,751	4,211,535	3.500964058

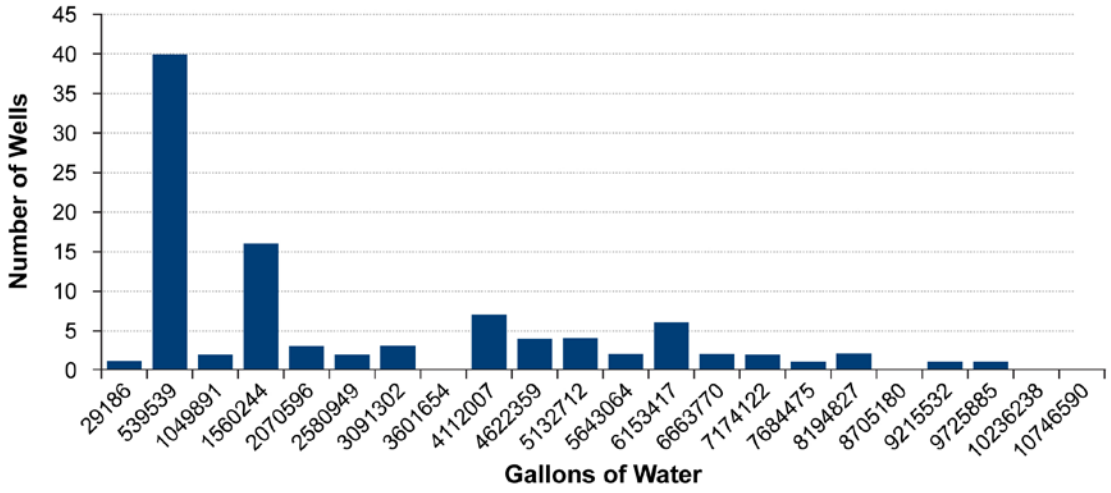


Figure 73. Histogram of 100 wells for total water volume (gallons) (fracfocus.org)

As seen in Table 36, the average volume per well was 2,537,853 gallons, with values ranging from 29,186 gallons to 26,315,125 gallons (fracfocus.org). Figure 73 is a histogram displaying the total volume of water, created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

Produced Water

No produced water data are available for Barnett shale. However, the Railroad Commission (RRC) of Texas requires every operator to report—into a query system—how much water is disposed. The current method used for disposal in the Barnett Shale is deep-well injected. The Injection Volume Query from the RRC database was used and monthly county-wide or operator-wide injected volumes can be obtained (TRRC 2011).

Violations

Figure 74 expresses the violations from 2009–2011 in Texas according to the severity of environmental effect (Wiseman 2012). Of the 35 total violations (Table 37), 35% of the violations are “minor - no effect” and “substantial.” “Procedural” account for about 20%, and “major” and “minor effect” account for 3%. It should be noted that these violations only include wells for which formal compliance or administrative orders were issued. Therefore, these data are not comprehensive and do not represent the total number of violations. Further information on violations can be found in D.7 of this appendix.

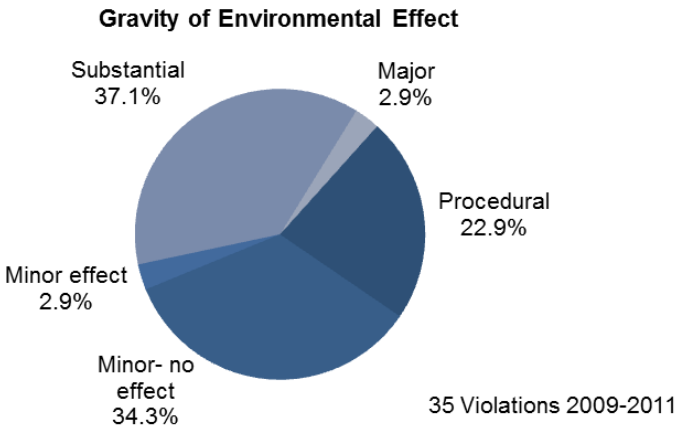


Figure 74. Texas violations (Wiseman 2012)

Table 37. Texas Violations (Wiseman 2012)

Texas		
Procedural	8	22.9%
Minor - no effect	12	34.3%
Minor effect	1	2.9%
Substantial	13	37.1%
Major	1	2.9%
Total	35	

Eagle Ford Shale Play, Texas

Overview

The Eagle Ford Shale play extends across 23 counties, covering an area of 20,000 square miles (Figure 75). The Eagle Ford Shale has an average thickness of 250 feet and contains an estimated 21 Tcf of shale gas and 3 billion barrels of shale oil (EIA 2011).

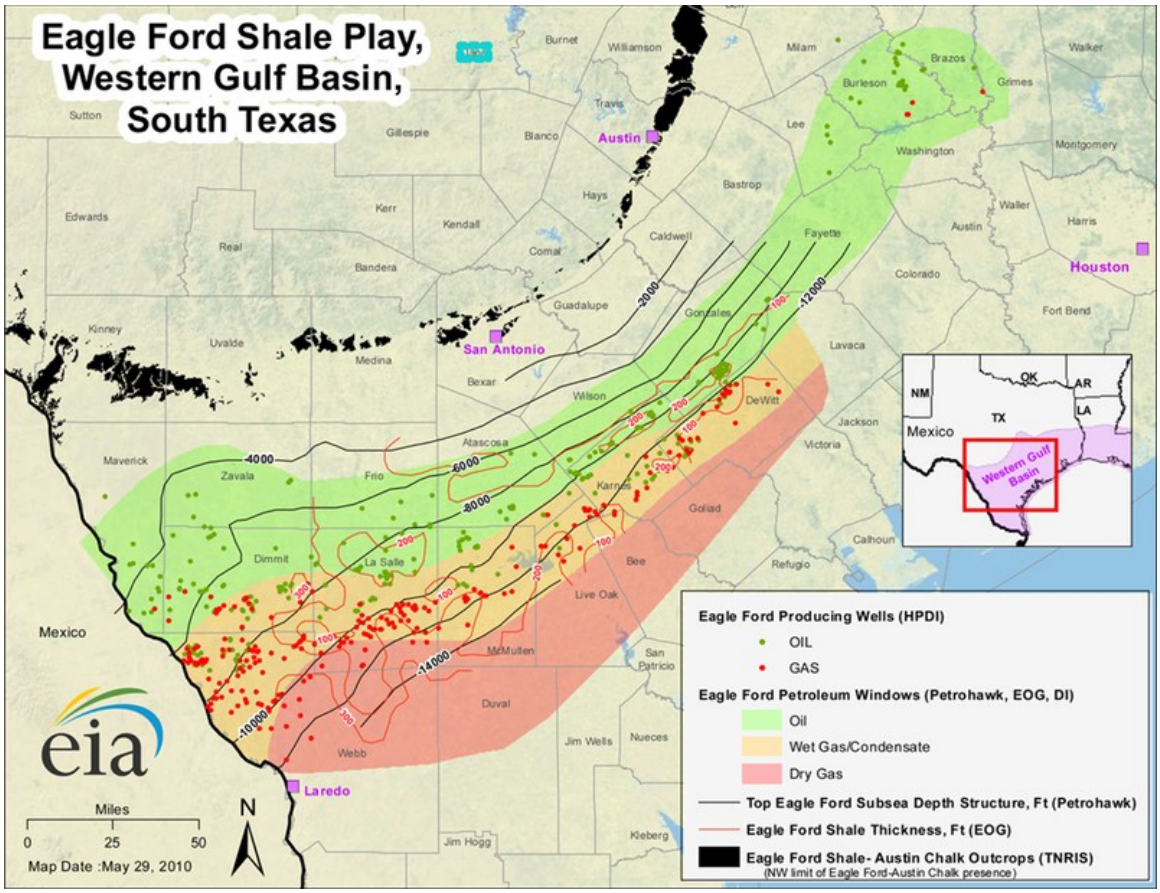


Figure 75. Extent of Eagle Ford Shale play (Eagle Ford Shale 2012)

Number of Wells

In 2008, Petrohawk drilled the first well in the Eagle Ford Shale, and since then, gas production has more than doubled—from 108 bcf in 2010 to 287 bcf in 2011. Oil production increased from more than 4 million barrels in 2010 to more than 36 million barrels in 2011 (TRRC 2012a). Increased production reflects the increases in drilling permits issued and in the number of oil and gas wells. Figure 76 shows the total number of producing oil and gas wells over the past three years.

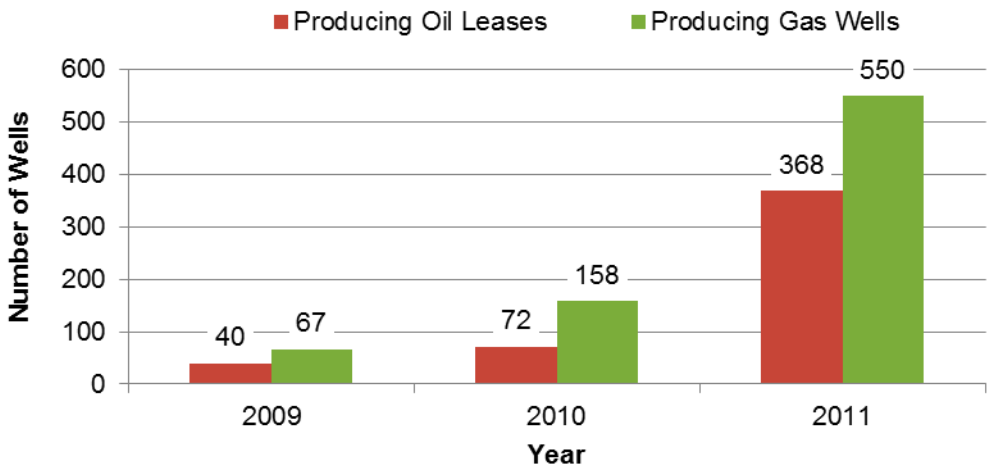


Figure 76. Number of producing oil and gas wells in Eagle Ford (Eagle Ford Shale 2012)

With 2,826 issued drilling permits in 2011 alone, the well count in Eagle Ford may steadily increase (Eagle Ford Shale 2012).

Water Usage per Well

Wells in the Eagle Ford Shale were randomly selected from fracfocus.org. Figure 77 shows a histogram of the water used per well, and Table 38 shows the average, maximum, and minimum water used per well.

Table 38. Fresh Water Use in Eagle Ford (in gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
3,751,751	7,084,098	77,658	7,006,440	1,276,506
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
3,608,905	4,386,965	3,116,039	1,270,927	-0.079

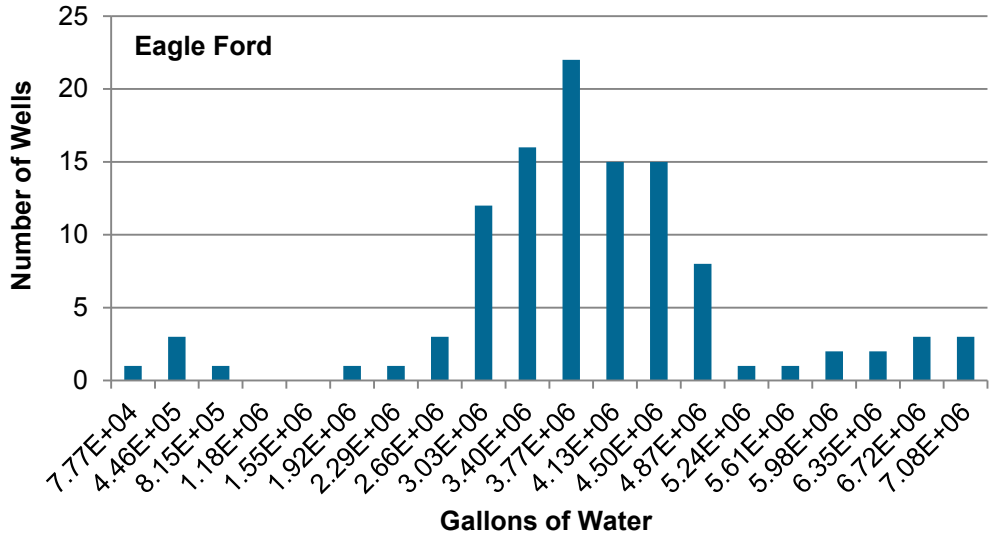


Figure 77. Fresh-water use in Eagle Ford per well (fracfocus.org)

The Texas Commission of Environmental Quality monitors surface water use in Texas. Surface water rights are issued to operators, and withdrawal amounts can be found on the TCEQ website (http://www.tceq.texas.gov/). However, withdrawal information is based on water-right number and is not shown on a well-to-well basis (TCEQ 2012).

Haynesville Shale Play, Louisiana

Overview

The Haynesville Shale extends over large sections of southwestern Arkansas, northwest Louisiana, and East Texas (Figure 19). It is up to 10,500 to 13,000 feet below the surface, with an average thickness of about 200–300 feet, and overs an area of about 9,000 square miles (TRRC 2012f).

Haynesville Shale is an important shale gas play in East Texas and Louisiana. Estimated recoverable reserves are as much as 60 Tcf, with each well producing 6.5 bcf on average (Hammes 2009). The formation came into prominence in 2008 as a potentially major shale gas resource, and production has boomed since late March 2008 (TRRC 2011). Producing natural gas from the Haynesville Shale requires drilling wells from 10,000 to 13,000 feet deep, with the formation being deeper nearer the Gulf of Mexico. The Haynesville Shale has recently been estimated to be the largest natural gas field in the contiguous 48 states, with an estimated 250 Tcf of recoverable gas (Nossiter 2008).

Figure 78. Extent of Haynesville Shale

The Haynesville Shale is lithologically heterogeneous, but is often an organic-rich mudstone. The composition varies greatly according to the geographic location and stratigraphic position of the mudstones—from calcareous mudstone near the ancient carbonate platforms and islands, to argillaceous mudstone in areas where submarine fans prograded into the basin and diluted organic matter. The Haynesville formation was deposited about 150 million years ago in a shallow offshore environment (Geology.com, 2012b).

Number of Wells

The State of Louisiana, Department of Natural Resources, provides information on monthly well counts. Well counts (Figure 79) have varied from 2009–2011 as old wells are abandoned and new wells are drilled and leased. However, total gas production (Figure 80) has increased from 2009–2011.

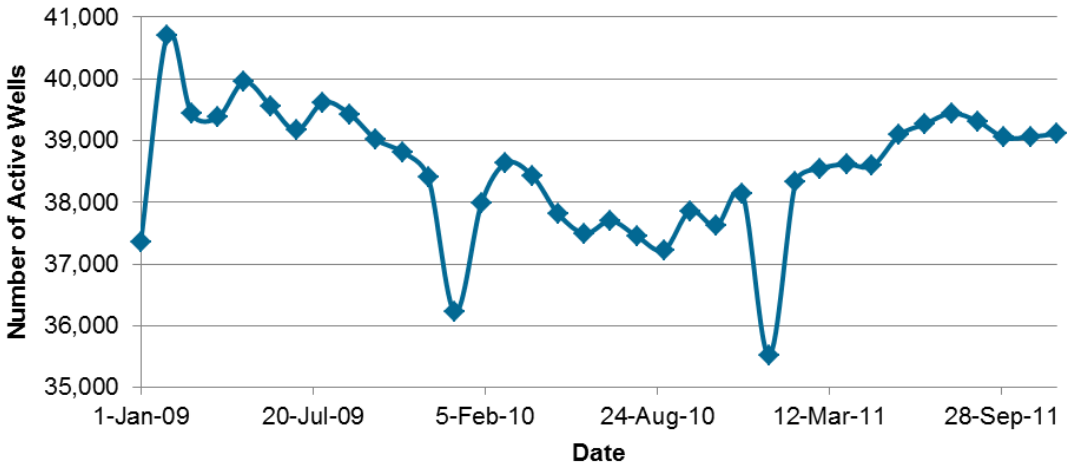


Figure 79. Monthly well count (2006–2011) (LADNR 2012b)

The total number of wells shows a significant drop at the end of 2010, after some natural fractures were seen in the formation cores extracted during test drilling. These fractures suggest

the risk of anthropogenic faulting of the surrounding land; however, drilling continued after these problems were resolved.

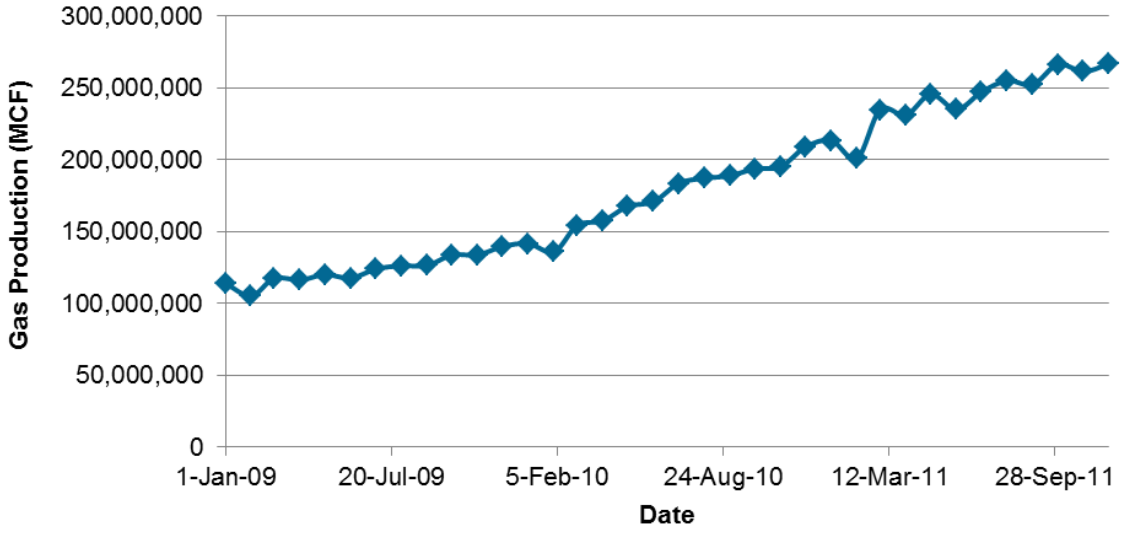


Figure 80. Monthly gas production (2009–2011) (EIA 2011)

Production is increasing almost linearly, despite a drop in well count. At the end of 2011, production was twice that in 2009.

Water Usage per Well

One hundred wells in the Haynesville Shale were randomly selected. Table 39 gives statistics on water usage, and Figure 81 is a histogram of the distribution of water usage distributed evenly into twenty bins.

Table 39. Analysis of Water Usage for 100 Haynesville Shale Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
4,568,683	9,567,936	8,736	9,559,200	2,243,797
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,925,256	6,255,663	3,875,203	2,380,460	-0.578

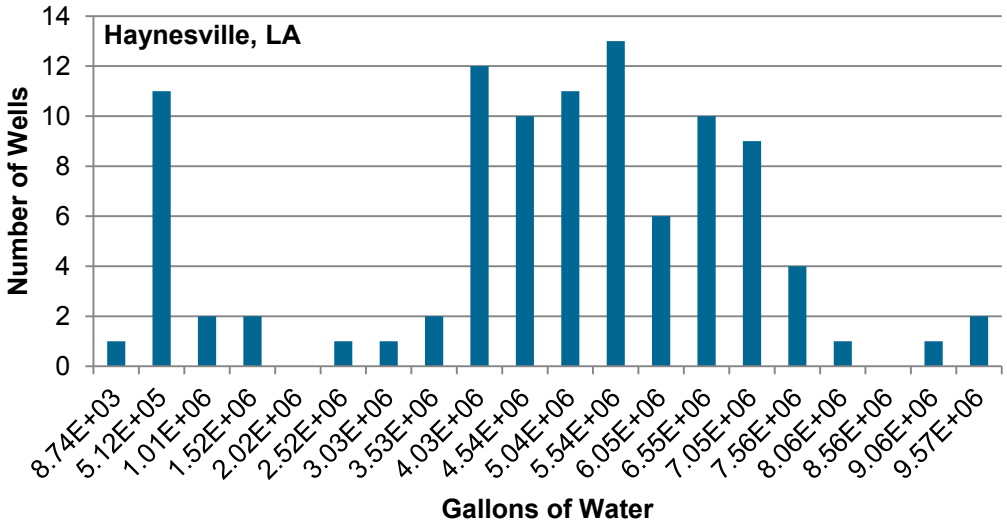


Figure 81. Fresh-water use for 100-well sample (fracfocus.org)

Violations

Figure 82 expresses the violations from 2008–2011 in Louisiana according to the severity of environmental effect. A majority of the violations are in the "procedural" category (Table 40). "Minor - no effect" violations make up about 30%, and "minor effect," "substantial," and "major" account for less than 10% (Wiseman 2012). These data include mostly Haynesville wells with compliance orders from January 1, 2008 through July 14, 2011. About 83 additional well incidents had insufficient information to be categorized. Further information on violations can be found in D.7 of this appendix.

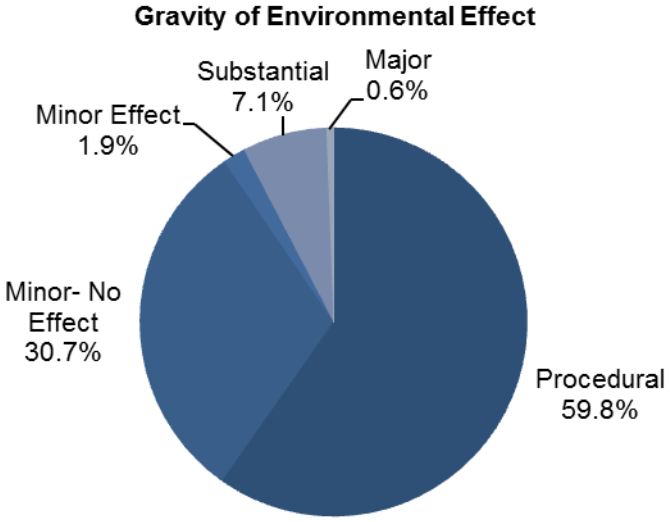


Figure 82. Louisiana violations (Wiseman 2012)

Table 40. Louisiana Violations (Wiseman 2012)

Procedural	95	59.8%
Minor - no effect	49	30.7%
Minor effect	3	1.9%
Substantial	11	7.1%
Major	1	0.6%
Total	158	

Upper San Juan Basin, Colorado, New Mexico

Overview

The San Juan Basin covers an area of about 7,500 square miles across the Colorado and New Mexico border in the Four Corners region (Figure 83). It spans about 100 miles north-south in length and 90 miles east-west in width. In the San Juan Basin, the total thickness of all coalbeds ranges from 20 to more than 80 feet. Coalbed methane production occurs primarily in coals of the Fruitland Formation, but some coalbed methane is trapped within the underlying and adjacent Pictured Cliffs Sandstone; many wells are present in both zones (EPA 2004).

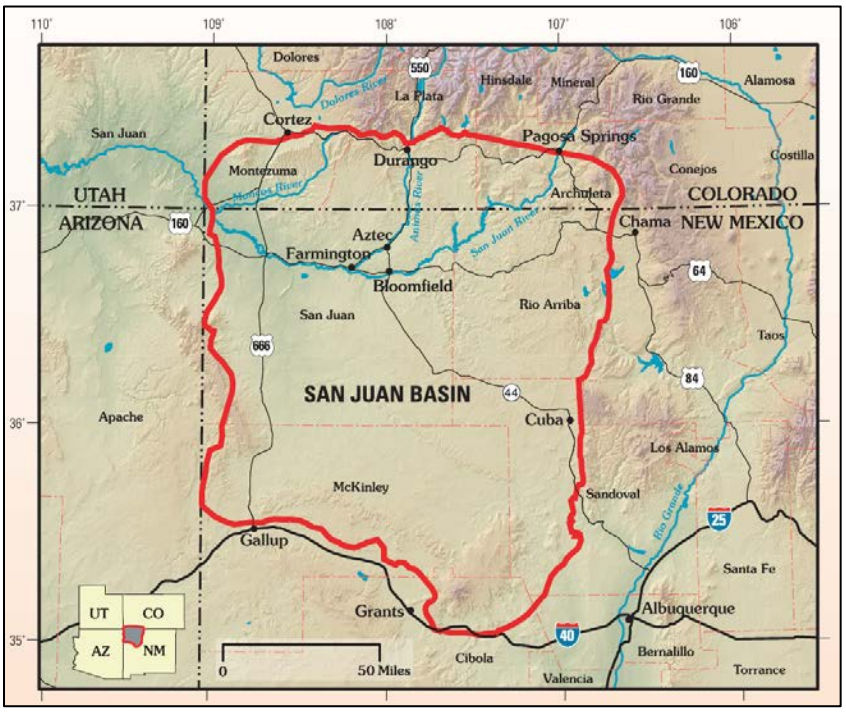


Figure 83. Extent of the San Juan Basin (USGS 2002a)

The Fruitland Formation is the primary coal-bearing unit of the San Juan Basin, as well as the target of most coalbed methane production. The Fruitland coals are thick and have individual beds up to 80 feet thick. The formation is composed of interbedded sandstone, siltstone, shale,

and coal. Some of the most important natural-gas-producing formations include the Fruitland, Pictured Cliffs, Mesaverde, Dakota, and Paradox formations and are located in La Plata County. Early development of natural gas began here in the 1920s. In La Plata County, coalbed methane production began in the late 1970s. Traditional natural gas reserves have been—and continue to be—developed at a steady pace (USGS 2002a).

Two types of natural gas wells exist within La Plata County: conventional and coalbed. Conventional gas wells are usually deeper—3,500 to 10,000 feet—and extract gas and oil from sandstone formations such as the Mesaverde and Dakota (La Plata Energy Council 2012). The shallower coalbed gas wells generally range from 1,000 to 4,000 feet deep and extract gas from coal-bearing formations (EPA 2004). The Fruitland formation is La Plata County's methane-rich coalbed formation.

Produced Water

Conventional wells initially produce large volumes of gas and very little water. Over time, gas production declines and water increases. Coalbed wells are just the opposite, producing large quantities of water and low gas quantities at the beginning; later, water production declines and gas production increases. Table 41 shows oil, gas, and water production from 2007–2011.

Table 41. Oil, Gas, and Water Production in La Plata County (COGCC 2012a)

Year	Oil Production (bbl)	Gas Production (Mcf)	Water Production (bbl)
2007	35,883	412,488,324	24,032,308
2008	38,038	425,541,599	20,154,062
2009	33,975	425,439,680	24,177,214
2010	33,396	422,450,451	31,942,703
2011	26,747	373,116,167	21,231,213

Based on the database provided by the Colorado Oil and Gas Conservation Commission (COGCC), five methods are used to dispose of water in La Plata County: disposal in a central pit well, injection on lease, disposal at a commercial disposal facility, evaporation in an onsite pit, and through surface discharge (COGCC 2012a). Table 42 and Figure 84 show disposal methods in La Plata County from 2007 to 2011.

Table 42. Produced Water and Disposal Method in La Plata County (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	637	1,213	726	646	736	791
Injected on Lease	350	362	175	201	179	253
Commercial Disposal Facility	47	60	61	53	37	52
Onsite Pit	2	2	1	2	1	1
Surface Discharge	NON	NON	NON	NON	NON	
SUM	1,036	1,638	963	901	953	1,098
Percentage	60%	61%	51%	48%	57%	55%
Estimation	1,725	2,697	1,876	1,872	1,674	1,969

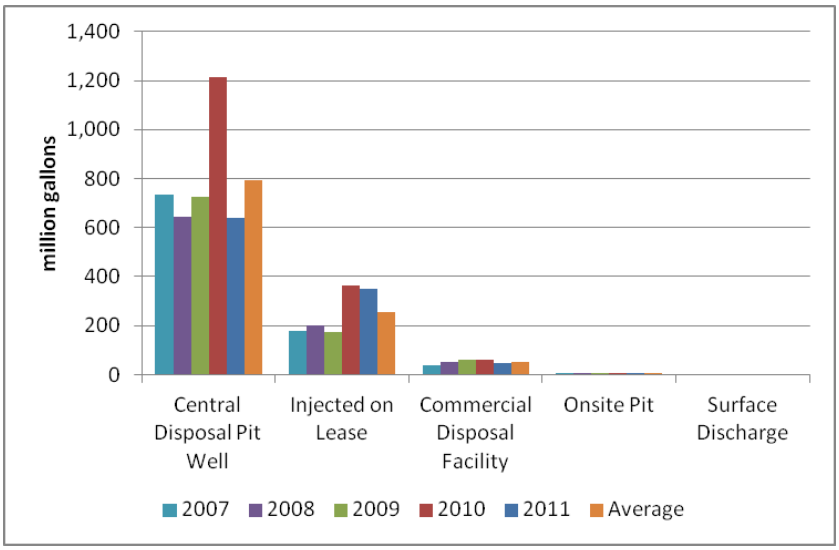


Figure 84. Water disposal volumes and methods in La Plata County (million gallons) (COGCC 2012a)

There is no surface discharge in La Plata County and minimal use of onsite pits. The most widely used method of disposal in La Plata County is a central disposal pit well. Some 70% of produced water is disposed in a central disposal pit well, 23% of produced water is injected on the lease, and 4.7% goes to a commercial disposal facility. Trends in the state of Colorado (Table 43) differ from those in La Plata County (Table 42).

Table 43. Produced Water and Disposal Method in the State of Colorado (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	4,609	3,314	3,237	3,135	3,678	3,595
Injected on Lease	8,095	11,243	6,715	7,194	11,666	8,983
Commercial Disposal Facility	1,248	2,266	1,665	1,303	962	1,489
Onsite Pit	3,001	2,962	3,213	5,128	3,588	3,579
Surface Discharge	2,191	1,218	1,219	283	677	1,117
Sum	19,144	21,003	16,049	17,042	20,572	18,762

Violations

For the state of Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Additionally, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired.

Green River Basin, Wyoming

Overview

The Green River Basin Oil Shale Field, as seen in Figure 85, is located in Wyoming, Utah, and Colorado, on the western flank of the Rocky Mountains. The main part of the Green River Basin Formation is located in the southwest portion of Wyoming. The Colorado oil shale is expected to hold the largest amount of oil from shale. Specifically, the Piceance Creek Basin is the large producer for oil shale in the Green River Formation (Oil Shale Gas 2012).

The estimates of the oil resource within the Green River Formation range from 1.3 to 2.0 trillion barrels. Because not all resources are recoverable, a moderate estimate of recoverable oil is about 800 billion barrels (Oil Shale Gas 2012).

Figure 85. Extent of Green River Formation

The Jonah Field is located in the northern part of the Green River Basin and has produced more than 1.0 Tcf of gas since production commenced in 1992 (Oil Shale Gas 2012). Development of this field resulted from applying advanced fracture stimulation techniques. The field has undergone several iterations of development, with some sections of the field currently being developed on 10-acre well spacing; the current well spacing is around 20 acres. The field produces from a series of stacked reservoirs within the Cretaceous Mesaverde and Lance Formations. The field is bounded between two faults forming a wedge-shaped field.

Water usage per well

One hundred wells in the Green River Formation were randomly selected. Table 44 gives statistics about water usage, and Figure 86 is a histogram of water usage distributed evenly into twenty bins.

Table 44. Analysis of Water Usage for 100 Green River Formation Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
1,076,417	4,451,034	14,467	4,436,567	1,230,306
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
367,522	1,665,741	201,280	1,464,461	1.40

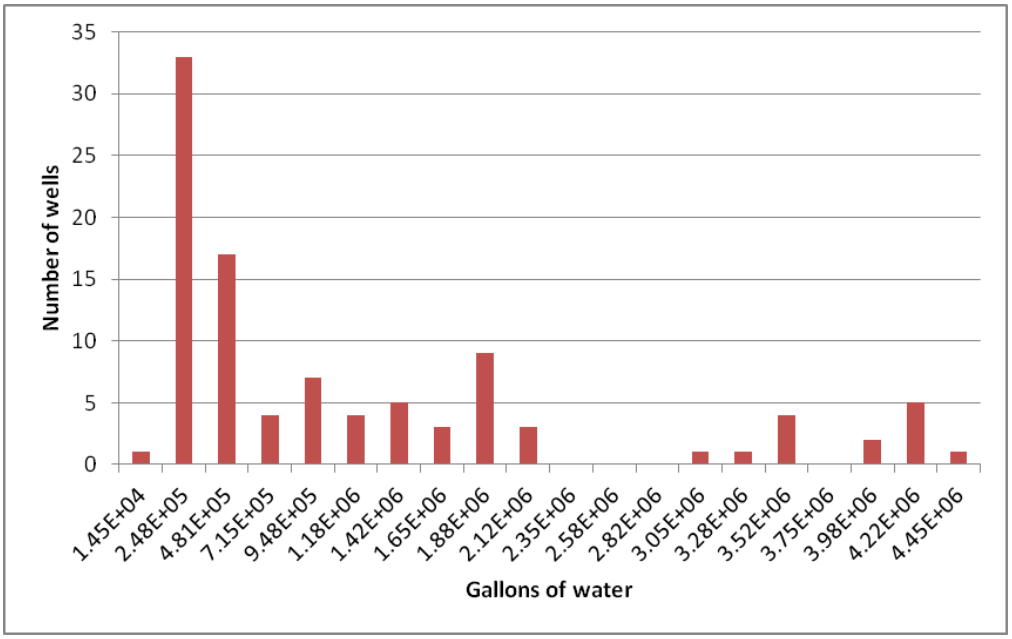


Figure 86. Fresh-water use for 100-well sample (fracfocus.org)

Figure 87 shows the volumes of hydraulic fracturing fluids used in Wyoming by county.

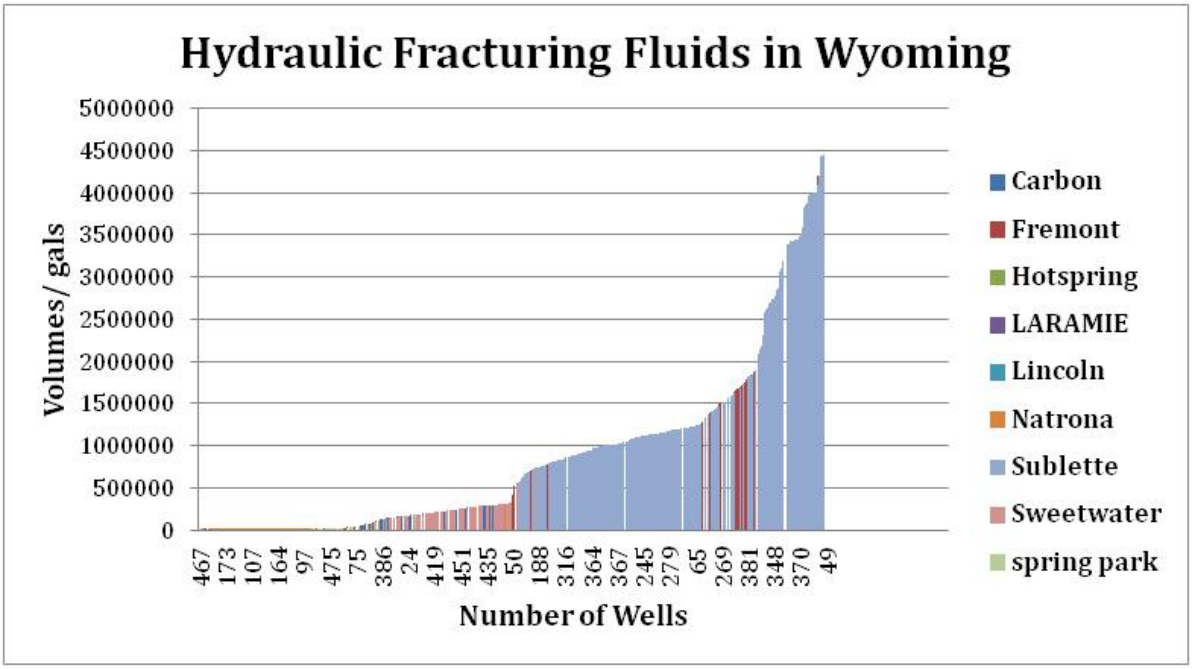


Figure 87. Volumes of hydraulic fracturing water (fracfocus.org)

Produced Water

Table 45 expresses the total oil, gas, and water produced within the Green River Basin from 2007–2011.

Table 45. Production of Oil, Gas, and Water in Green River Basin (WOGCC 2012)

Year	Oil Production (barrels)	Gas Production (Mcf)	Water Production (Barrels)
2007	15,491,483	1,218,888,397	125,613,453
2008	15,824,924	1,371,741,392	150,830,391
2009	15,925,806	1,428,200,434	158,560,401
2010	20,544,588	1,418,379,334	169,901,204
2011	15,385,222	1,347,348,632	177,151,681

Table 46 provides injection volumes by field, although not all fields are represented.

Table 46. Injection Volumes (WOGCC 2012)

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
Big Piney	577,239	167,646	189,178	70,354	40,247
Bison Basin	1,989,960	2,564,857	2,223,756	2,354,332	2,296,464
Brady	4,419,146	2,612,544	1,943,879	2,003,854	4,688,163
Cow Creek	4,406,339	8,174,082	4,635,125	5,517,186	6,288,081
Fontenelle	111,267	117,390	115,376	110,948	102,167
Green River Bend	592,890	381,857	549,775	616,873	432,311
Jonah	1,367,707	2,010,190	1,588,080	1,991,187	2,703,926

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
LaBarge	167,441	1,653,772	1,752,291	2,079,953	1,344,187
Lost Soldier	23,577,864	25,017,789	32,557,565	29,490,274	37,367,198
Mahoney Dome	926,644	721,983	1,188,006	1,085,123	1,111,673
McDonald Draw	535,996	494,630	414,810	388,833	377,482
Patrick Draw	1,551,255	4,012,343	1,196,017	1,020,284	1,179,744
Pinedale	954,458	6,749,055	11,951,930	12,027,080	11,482,543
Saddle Ridge	221,413	206,610	227,843	231,330	208,498
Star Corral	288,567	221,015	172,686	190,853	175,222
Tierney	1,083,636	1,813,532	1,660,262	1,831,283	1,004,778
Tip Top	455,781	548,822	427,670	387,878	389,175
WC	16,900,921	33,853,193	31,456,801	24,984,327	12,428,968
Wertz	20,610,169	25,384,888	1,953,919	24,188,672	30,240,574

Severity of Environmental Impact Matrix

Table 47 shows the categorization of environmental impacts for shale gas operations.

Table 47. Severity of Environmental Impact (Wiseman 2012)

Severity of environmental effect	Activity for which violation occurred	Enforcement action	Environmental factors
Procedural	- Permitting - Reporting - Testing - Financial assurance	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in violation/field notes that failure to obtain permit, report, conduct a test, or provide financial guarantee resulted in environmental damage
Minor - no effect	- Equipment failures - Pit construction, operation, and maintenance - Failure to prevent oil and gas waste - Commingling oil and gas - Site maintenance, such as moving weeds - Sign posting and hazard labels	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in field notes that violation resulted in any environmental damage
Minor effect	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order paired with very small environmental effect	Small spills and improperly disposed wastes (typically less than 5 barrels of produced water or oil) that did not move offsite or otherwise suggest substantial environmental damage. Small quantities of air emissions (e.g., slightly over the daily limit).
Substantial	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Failure to plug well twelve months after abandonment or inactivity - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + substantial environmental effect; remediation order	Medium spills and improperly disposed wastes (typically more than 5 barrels and less than 10 for produced water or oil that stayed on site). For fracturing fluid spills, any spill more than 1 barrel was considered major.
Major	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + > substantial environmental effect (or high penalty + substantial environmental effect); remediation order + major environmental effect	Large spills or improperly disposed of wastes (typically 10 or more barrels, small to large spills that moved off site and impacted a resource (e.g., drainage ditch, wetland). Any spill of fracturing fluid > 1 barrel.

Appendix E: Assumptions Used in ReEDS

What is ReEDS?[250]

The Regional Energy Deployment System is an optimization model used to assess the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States into the future. The model, developed by NREL, is designed to analyze critical energy issues in the electric sector, especially with respect to the effect of potential energy policies such as clean energy and renewable energy standards or carbon restrictions.

ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies—including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Qualitative Model Description

To assess competition among the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost-minimization routine is performed for each of twenty 2-year periods from 2010 to 2050. The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel prices, and CO_2 emissions. Time in ReEDS is subdivided within each 2-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time slices. Also, there is one additional summer-peak time slice. These 17 annual time slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year—with both conventional and renewable generators.

Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources such as wind and solar power come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much greater level of geographic disaggregation than do other long-term, large-scale, capacity expansion models. ReEDS uses 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into four levels of larger regional groupings—balancing areas, reserve-sharing groups,

[250] "What is ReEDS?" is taken from the 2011 detailed documentation for the ReEDS model.
Short, W., et al., Regional Energy Deployment System (ReEDS). NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

North American Electric Reliability Council regions,[251] and interconnects. States are also represented for the inclusion of state policies.

Many of the data inputs in ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources enables ReEDS to calculate transmission distances, as well as the benefits of dispersed wind farms, PV arrays, or CSP plants supplying power to a demand region. Offshore wind is distinguished from onshore wind both in terms of technology cost/performance and resources. The wind and CSP supply curves are subdivided into five resource classes based on the quality of the resource—strength and dependability of wind or solar isolation.

Regarding resource variability and grid reliability, ReEDS also allows electric and thermal storage systems to be built and used for load shifting, resource firming, and ancillary services. Four varieties of storage are supported: pumped hydropower, batteries, compressed air energy storage, and thermal storage in buildings.

Along with wind and solar power data, ReEDS provides supply curves for hydropower, biomass, and geothermal resources in each of the 134 balancing areas. The geothermal and hydropower supply curves are in megawatts of recoverable capacity, and the biomass supply curve is in million British thermal units of annual feedstock production. In addition, other carbon-reducing options are considered. Nuclear power is an option, as is CCS on some coal and natural gas plants. CCS is treated simply, with only an additional capital cost for new coal and gas-fired power plants for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation and sequestration process. Also, a limited set of existing coal plants can choose to retrofit to CCS for an associated cost, as well as a performance, penalty. The major conventional electricity-generating technologies considered in ReEDS include hydropower, simple- and combined-cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by the following:

- Capital cost ($/MW)
- Fixed and variable operating costs ($/MWh)
- Fuel costs ($/MMBtu)
- Heat rate (MMBtu/MWh)
- Construction period (years)
- Equipment lifetime (years)
- Financing costs (such as nominal interest rate, loan period, debt fraction, debt-service-coverage ratio)
- Tax credits (investment or production)

[251] North American Electric Reliability Corporation, October 2010. "2010 Long-Term Reliability Assessment." http://www.nerc.com/files/2010%20LTRA.pdf. Accessed November 2, 2011.

- Minimum turndown ratio (%)
- Quick-start capability and cost (%, $/MW)
- Spinning reserve capability
- Planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters—accounting for fundamental differences. For instance, heat rate is replaced with round-trip efficiency in pure storage technologies, and the dispatchability parameters—such as fuel cost, heat rate, turndown ratio, and operating reserve capability—are not used for non-dispatchable wind and solar technologies. These variable generation technologies are further characterized by changes in generation levels over the course of a year.

The model includes consideration of distinguishing characteristics of each conventional generating technology. There are several types of coal-fired power plants within ReEDS, including pulverized coal with and without sulfur dioxide scrubbers, advanced pulverized coal, integrated gasification combined cycle, biomass co-firing, and integrated gasification combined cycle with CCS options. Coal-plant generation is discouraged from daily cycling via a cost penalty, which represents a combination of additional fuel burned, heat rate drop-off, and mechanical wear-and-tear. Natural gas plants represented in ReEDS include simple-cycle combustion turbines, combined-cycle plants, and combined-cycle with CCS plants. Combined-cycle natural gas plants can provide some spinning reserve and quick-start capability, and simple-cycle gas plants can be used cheaply and easily for quick-start power. Nuclear power is represented as one technology in ReEDS and is considered to be baseload.

Retirement of conventional generation and hydropower can be modeled through exogenous specification of planned retirements or based on usage characteristics of the plants. All retiring non-hydro renewable plants are assumed to be refurbished or replaced immediately because the site is already developed and has transmission access and other infrastructure.

ReEDS tracks emissions of carbon and sulfur dioxide from both generators and storage technologies. Caps can be imposed at the national level for these emissions, and constraints can also be applied to impose caps at state or regional levels. There is another option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be defined exogenously. In addition, ReEDS can impose clean energy or renewable energy standards at the regional or national level.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the Reference scenario, price elasticity of demand is integrated into the model: the exogenously defined demand projection can be adjusted up or down based on a comparison of an estimated business-as-usual electricity price path and a calculation of electricity price within the model for each of the twenty 2-year periods. For coal and natural gas

pricing, supply curves based on the Annual Energy Outlook[252] have been developed and used in ReEDS.

Natural Gas Supply Curve Background and Development

The EIA's Annual Energy Outlook 2011 has two specific scenarios that attempt to model the effects of high or low abundance of natural gas supply: High-EUR and Low-EUR. The High-EUR scenario increases the total unproved technically recoverable shale gas resource from 827 Tcf in the Mid-EUR baseline scenario to 1,230 Tcf. In addition, the ultimate recovery per shale gas well is 50% higher than in the baseline scenario. Low-EUR reduces recoverable shale gas resource to 423 Tcf and 50% lower ultimate recovery per shale gas well than in the Mid-EUR baseline scenario.

Deriving the coefficients for this study relied on assuming a linear regression model and employing an ordinary least-squares method. Linear regression is a statistical technique that examines the relationship between one dependent variable (Y) and multiple explanatory variables, or regressors (X), taking the linear form:

$$Y_i = \beta_0 + \beta_1 * X_1 + \beta_2 * X_2 + \cdots \beta_n * X_n + \varepsilon_i$$

The estimated coefficients represent the marginal impact of a 1-unit change in each independent variable $\mathbf{X_i}$ on Y. Linear regression is often used for prediction or forecasting.[253]

In this case, because the objective was to develop a model to closely model the relationship between natural gas in the electric sector and consumption in the electric sector in different scenarios, the electric-sector price was modeled based on the following predictors: electric-sector consumption, economy-wide consumption, year (2012–2035), and the natural gas scenario case.[254] Each electric-sector price for each of the Annual Energy Outlook scenarios from 2012–2035 was treated as an independent observation used to estimate coefficients in the following model:

$$\begin{aligned} &Electric\ Sector\ Price_i \\ &\quad = \beta_0 + \beta_1 * Electric\ Sector\ Consumption_i + \beta_2 \\ &\quad * Economy - wide\ Consumption_i \\ &\quad + \sum_{j=1}^{12} \beta_j * Year + \sum_{k=1}^{4} \beta_k * Natural\ Gas\ Scenario + \varepsilon_i \end{aligned}$$

Observations that occurred in High-EUR and Low-EUR were coded accordingly, creating two additional intercept shifter "dummy" variables. The year, rather than coded as continuous, was coded as a dummy variable to capture non-linear variation from year to year. To account for the

[252] Annual Energy Outlook 2011. DOE/EIA-0383. Washington, DC: U.S. Energy Information Administration.
[253] Damodar, Gujarati. Basic Econometrics (5th edition). McGraw Hill, 2007.
[254] Data for 2008–2011 as well as outlier scenarios (polmax0314a, polmaxlco20321a, polmaxlp0316a, lgbama050218a, lgbama200218a, aeo2010r1118a, oghtec110209a, ogltec110209a, hilng110209a, lolng110209a) were removed when running the model.

predictor influence of economy-wide consumption, the average value for the year and the scenario for each data point were multiplied by β_2 (the derived electric-sector consumption coefficient). As a result, the intercept varied by year and by scenario, while the slope remained the same across year and scenario. The intercept and shifter for the years 2036–2050 was held constant with model results in 2035.

The following tables summarize the assumptions used in ReEDS for: technology costs and performance (Table 48), wind performance (Table 49), CSP performance (Table 50), and utility-scale PV performance (Table 51).

Table 48. Technology Cost ($2010) and Performance Assumptions Used in ReEDS

	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
Coal Integrated Gasification Combined-Cycle CCS				
2010	4,075	7	32	9.0
2020	4,075	7	32	9.0
2030	4,075	7	32	7.9
2040	4,075	7	32	7.9
2050	4,075	7	32	7.9
CSP				
2010	7,179 (8,217)[a]	NA	50 (80)	NA
2020	6,639 (4,077)	NA	50 (66)	NA
2030	5,398 (2,983)	NA	50 (51)	NA
2040	4,778 (2,983)	NA	50 (47)	NA
2050	4,778 (2,983)	NA	50 (45)	NA
Combined-Cycle Plants				
2010	1,250	4	6	7.5
2020	1,250	4	6	6.7
2030	1,250	4	6	6.7
2040	1,250	4	6	6.7
2050	1,250	4	6	6.7
Combined-Cycle Plants CCS				
2010	3,348	10	19	10.0
2020	3,267	10	19	10.0
2030	3,267	10	19	10.0
2040	3,267	10	19	10.0
2050	3,267	10	19	10.0
Simple-Cycle Combustion Turbines				
2010	661	30	5	12.5
2020	661	30	5	10.3
2030	661	30	5	10.3
2040	661	30	5	10.3
2050	661	30	5	10.3

		Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
New Coal					
	2010	2,937	4	23	10.4
	2020	2,937	4	23	9.4
	2030	2,937	4	23	9.0
	2040	2,937	4	23	9.0
	2050	2,937	4	23	9.0
Nuclear					
	2010	6,199 (3,100)	NA	129	9.7
	2020	6,199 (3,100)	NA	129	9.7
	2030	6,199 (3,100)	NA	129	9.7
	2040	6,199 (3,100)	NA	129	9.7
	2050	6,199 (3,100)	NA	129	9.7
Utility-Scale PV					
	2010	4,067 (4,067)	NA	51 (21)	NA
	2020	2,560 (2,013)	NA	46 (20)	NA
	2030	2,351 (1,912)	NA	42 (15)	NA
	2040	2,191 (1,797)	NA	38 (13)	NA
	2050	2,058 (1,720)	NA	33 (9)	NA
Wind Offshore					
	2010	3,702 (3,702)	0 (23)	101 (16)	NA
	2020	3,355 (3,284)	0 (17)	101 (16)	NA
	2030	3,042 (2,912)	0 (14)	101 (16)	NA
	2040	3,042 (2,744)	0 (12)	101 (16)	NA
	2050	3,042 (2,744)	0 (12)	101 (16)	NA
Wind Onshore					
	2010	2,012 (2,012)	0 (8)	60 (12)	NA
	2020	2,012 (1,964)	0 (5)	60 (12)	NA
	2030	2,012 (1,865)	0 (5)	60 (12)	NA
	2040	2,012 (1,805)	0 (5)	60 (12)	NA
	2050	2,012 (1,805)	0 (5)	60 (12)	NA

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 49. Wind Performance Assumptions

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2010			
	Class 3	0.32 (0.35)[a]	0.36 (0.37)
	Class 4	0.36 (0.39)	0.39 (0.41)
	Class 5	0.42 (0.43)	0.45 (0.44)
	Class 6	0.44 (0.46)	0.48 (0.48)
	Class 7	0.46 (0.50)	0.50 (0.52)

Wind Power Class	On-Shore Wind	Off-Shore Wind
2020		
Class 3	0.33 (0.38)	0.37 (0.39)
Class 4	0.37 (0.42)	0.39 (0.44)
Class 5	0.42 (0.45)	0.45 (0.47)
Class 6	0.44 (0.48)	0.48 (0.51)
Class 7	0.46 (0.52)	0.50 (0.55)
2030		
Class 3	0.35 (0.38)	0.38 (0.40)
Class 4	0.38 (0.43)	0.40 (0.45)
Class 5	0.43 (0.46)	0.45 (0.48)
Class 6	0.45 (0.49)	0.48 (0.51)
Class 7	0.46 (0.53)	0.50 (0.55)
2040		
Class 3	0.35 (0.38)	0.38 (0.40)
Class 4	0.38 (0.43)	0.40 (0.45)
Class 5	0.43 (0.46)	0.45 (0.48)
Class 6	0.45 (0.49)	0.48 (0.51)
Class 7	0.46 (0.53)	0.50 (0.55)
2050		
Class 3	0.35 (0.38)	0.38 (0.40)
Class 4	0.38 (0.43)	0.40 (0.45)
Class 5	0.43 (0.46)	0.45 (0.48)
Class 6	0.45 (0.49)	0.48 (0.51)
Class 7	0.46 (0.53)	0.50 (0.55)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 50. CSP Performance Assumptions

Wind Power Class	Capacity Factor
2010	
Class 1	0.28 (0.28)[a]
Class 2	0.37 (0.37)
Class 3	0.42 (0.42)
Class 4	0.44 (0.44)
Class 5	0.46 (0.46)
2020	
Class 1	0.28 (0.37)
Class 2	0.37 (0.47)
Class 3	0.42 (0.52)
Class 4	0.44 (0.54)
Class 5	0.46 (0.56)
2030	
Class 1	0.37 (0.37)

Wind Power Class	Capacity Factor
Class 2	0.47 (0.47)
Class 3	0.52 (0.52)
Class 4	0.54 (0.54)
Class 5	0.56 (0.56)
2040	
Class 1	0.37 (0.37)
Class 2	0.47 (0.47)
Class 3	0.52 (0.52)
Class 4	0.54 (0.54)
Class 5	0.56 (0.56)
2050	
Class 1	0.37 (0.37)
Class 2	0.47 (0.47)
Class 3	0.52 (0.52)
Class 4	0.54 (0.54)
Class 5	0.56 (0.56)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 51. Utility-Scale PV Performance Assumptions

Year	Capacity Factor
2010	0.16–0.27
2020	0.16–0.27
2030	0.16–0.27
2040	0.16–0.27
2050	0.16–0.27

Treating Plant Retirement in ReEDS[255]

Assumptions about the retirement of conventional-generating units can have considerable cost implications. Considerations that go into the decision-making process on whether or not an individual plant should be retired involve a number of factors—specifically, the economics of plant operations and maintenance. Projecting these economic considerations into the future given the uncertainties involved is beyond the scope of ReEDS. Instead, ReEDS uses the following three retirement options that are not strictly economic:

- *Scheduled lifetimes for existing coal, gas, and oil.* These retirements are based on lifetime estimate data for power plants from Ventyx (2010). Near-term retirements are based on the officially reported retirement date as reported by EIA 860, EIA 411, or Ventyx unit research (Ventyx 2010). If there is no officially reported retirement date, a lifetime-based

[255] This section was taken from existing documentation of the ReEDS model.
Short, W. et al. (2011). "Regional Energy Deployment System (ReEDS)," NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

retirement is estimated based on the unit's commercial online date and the following lifetimes:

  - Coal units (< 100 MW) = 65 years
  - Coal units (> 100 MW) = 75 years
  - Natural gas combined-cycle unit = 55 years
  - Oil-gas-steam unit = 55 years

- *Usage-based retirements of coal.* In addition to scheduled retirements, coal technologies, including co-fired coal with biomass, can retire based on proxies for economic considerations. Any capacity that remains unused for energy generation or operating reserves for 4 consecutive years is assumed to retire. Coal capacity is also retired by requiring a minimum annual capacity factor; after every 2-year investment period, if a coal unit has a capacity factor of less than this minimum capacity factor during the 2-year period, an amount of coal capacity is retired such that the capacity factor increases to this minimum threshold (10% in 2030, 20% in 2040, and 30% in 2050). Coal plants are not retired under this algorithm until after 2020.
- *Scheduled nuclear license-based retirements.* Nuclear power plants are retired based on the age of the plant. Under default assumptions, older nuclear plants that are on line before 1980 are assumed to retire after 60 years (one re-licensing renewal), whereas newer plants (on line during or after 1980) are assumed to retire after 80 years (two relicensing renewals). Other options can be implemented, such as assuming 60- or 80-year lifetimes for all nuclear plants.

Glossary

annulus	The space between two concentric lengths of pipe or between pipe and the hole in which it is located.
associated gas	Natural gas that occurs with crude oil reservoirs, either as free gas or dissolved in solution. It is usually produced with crude oil.
basin	A petroleum geology term that refers to a dip in the Earth's crust usually filled or being filled with sediment. Basins are usually relatively large areas where oil and gas can be found.
billion cubic feet (bcf)	Unit used to measure large quantities of gas, approximately equal to 1 trillion British thermal units.
billion cubic feet per day (bcf/d)	Unit used to measure the daily volume of gas produced, stored, transported, or consumed.
bradenhead	A device that is used during inner-string grouting or pressure grouting operations. The bradenhead is situated at the top of the well casing, where it allows a drill pipe to be extended into the well while the well head is sealed and the annulus between the well casing and drill pipe is pressurized. Also termed casing head, cement head, or largen head.
British thermal unit (Btu)	An energy unit equivalent to the amount of energy needed to raise the temperature of 1 pound of water 1°F from 58.5°F to 59.5°F under standard pressure of 30 inches of mercury. Commonly used for measuring gas and other energy sales quantities.
burner tip	The point of end-use consumption of a particular fuel.
cement bond log	A representation of the integrity of the cement job, especially whether the cement is adhering solidly to the outside of the casing. The log is typically obtained from one of a variety of sonic-type tools.
coal-bed methane (CBM)	Natural gas, primarily methane, generated during coal formation and recovered by pumping water from coal seams, allowing gas to escape through shallow wells. It is generally referred to as one type of unconventional gas.
closed-loop drilling	Drilling and fracturing operation that contains all fluids in tanks and other closed-to-the-atmosphere equipment. Closed-loop drilling does not use open pits and therefore can reduce the risks of leaks and spills.
Combined-cycle	An electric generating technology in which conventional gas combustion turbines are combined with heat-recovery, steam-powered generation units, increasing the overall efficiency of the generating facility. Electricity is produced from both the feed gas, as well as from otherwise lost waste heat exiting gas turbines. In a conventional steam power generating facility, electricity is generated only from the feed gas.
completion	Preparing a newly drilled well for production; usually involves setting casing (pipe that lines the interior of a well to prevent caving and protect against ground-water contamination) and perforating the casing to establish communication with the producing formation.
compressed natural gas	Highly compressed natural gas stored and transported in high-pressure containers, typically greater than 3,000 pounds per square inch (200 bar); commonly used for transport fuel.
condensates	Light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas.
cubic feet (cf)	Common unit of measurement of gas volume equivalent to the amount of gas required to fill a volume of 1 cubic foot under given temperature and pressure conditions.

deep-well injection	Technique for disposal of frac flowback or produced water in deep formations isolated from producing zones and fresh-water aquifers.
dry gas	Natural gas, mainly methane, that remains after liquid hydrocarbon components have been removed, making it suitable for pipeline shipping, liquefied natural gas processing, or industrial usage.
ethane (C_2H_6)	A normally gaseous natural gas liquid hydrocarbon extracted from natural gas or refinery gas streams.
flaring	The process of disposing uncommercial or otherwise unwanted gas by burning. Operators often flare associated gas in regions with limited gas markets.
formation	Refers to either a certain layer of the Earth's crust, or a certain area of a layer; often refers to the area of rock where a petroleum or natural gas reservoir is located.
fracturing (or fracking)	See hydraulic fracturing.
frac flowback	Fluids that are returned to the surface immediately following hydraulic fracturing that include mostly the injected water, sand, and chemicals used for the fracturing.
geographic information system (GIS)	Integrated hardware, software, and data used for capturing, managing, analyzing, and displaying all forms of geographically referenced information.
gas-to-liquids process	A process that converts natural gas into synthetic liquid petroleum products, such as diesel fuel and blending feedstock.
glycol dehydrators	Facilities in which a glycol-based process removes water from produced natural gas, often in the field and before processing. The removal of water is needed to prevent corrosion and water freezing in pipelines.
green completion	Using technology to recover gas that may otherwise be vented or flared during the completion phase of a natural gas well. Also known as reduced emission completions.
harmonization	A meta-analytical procedure for adjusting published estimates from life cycle assessment to develop a set of directly comparable estimates. Harmonization clarifies a body of published estimates in ways useful to decision-making and future analyses. See nrel.gov/harmonization for further description and resources.
hydraulic fracturing (or hydrofracking)	The process of creating fractures in non-porous rock using specially formulated, water-based solutions forced into wells at extremely high pressure; the cracks in the rock allow for the release and collection of the natural gas. Fracking can be done in vertical or horizontal wells.
induced seismicity	Seismic activity (e.g., earthquakes) that is caused by injection of fluids into deep formations in proximity to natural faults.
life cycle assessment (LCA)	A technique to assess environmental impacts associated with all stages of a product's life from "cradle to grave" (i.e., from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or decommissioning). LCAs can be applied to water, energy, greenhouse gas emissions, or other metrics of interest.
liquefied natural gas (LNG)	Natural gas, mainly methane, that has been cooled to very low temperature (-259°F) so that it will condense into a transportable colorless and odorless liquid.
methane (CH_4)	The lightest and most abundant of the hydrocarbon gases, it is the principal component of natural gas and LNG.
natural gas	Naturally occurring mixture of hydrocarbon gases from underground sources composed mainly of methane (more than 85% in some cases), ethane, propane, butane, pentane, and impurities including carbon dioxide, helium, nitrogen, and hydrogen sulfide.

natural gas liquids	Natural gas components—including ethane, propane, butane, pentane, and condensates—that are liquid at surface conditions. It does not include methane, which remains in gaseous phase at surface conditions.
New York Mercantile Exchange	The first U.S. exchange to trade natural gas futures contracts; the New York Mercantile Exchange has contracts with major delivery points.
play (shale play, shale gas play)	A geographic area that has been targeted for exploration due to favorable geoseismic survey results, well logs, or production results from a new well in the area. An area comes into play when it is generally recognized that there is an economic quantity of oil or gas to be found.
primacy (primary enforcement responsibility)	The authority to implement the Underground Injection Control Program. To receive primacy, a state, territory, or tribe must demonstrate to EPA that its Underground Injection Control Program is at least as stringent as the federal standards; the state, territory, or tribal Underground Injection Control requirements may be more stringent than the federal requirements. EPA may grant primacy for all or part of the Underground Injection Control Program (e.g., for certain classes of injection wells).
produced water	Water that is extracted with the oil and gas from the producing formation. Produced water is usually highly saline and not usable without treatment.
quad	A unit of energy equal to 10^{15} Btu, roughly equal to 1 Tcf.
reserves	Volumes of hydrocarbons that have a chance of being economically and technically producible.
reservoir	A subsurface rock or formation having sufficient porosity and permeability to store and transmit fluids such as gas, oil, and water. Reservoirs are typically composed of sedimentary rocks with an overlying or adjoining impermeable seal or cap rock.
shale gas	Shale gas is defined as a natural gas produced from shale rock. Shale has low matrix permeability; therefore, gas production in commercial quantities requires fracturing or other stimulation to improve permeability.
social license to operate	A project that has the ongoing approval within the local community and other stakeholders, ongoing approval or broad social acceptance, and, most frequently, as ongoing acceptance.
trillion cubic feet (Tcf)	Unit used to measure large quantities of gas, typically reserve sizes. Approximately equal to 1 quad of energy.
unconventional gas	Unconventional gas refers to gas produced from coal seams (coal-bed methane), shale rocks (shale gas), and rocks with low permeability (tight gas). Once gas is produced from these reservoirs, it has the same properties of gas produced from conventional (i.e., sedimentary reservoirs with high porosity and permeability) sources. Unconventional gas may have high levels of natural gas liquids (an exception is coal-seam gas, which tends to be very dry with high proportion of methane versus natural gas liquids) and may have low or high levels of carbon dioxide and high and low levels of sulfur (sour or sweet). Because unconventional reservoirs have low permeability, artificial methods to increase gas flows, such as mechanical or chemical fracking, is often required before the wells are able to produce commercial quantities of gas.

Underground Injection Control Program	The program that EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act that is responsible for regulating the underground injection of fluids. This includes setting the minimum federal requirements for construction, operation, permitting, and closure of underground injection wells. There are six categories of wells regulated under the Underground Injection Control ranging from Class I to Class VI. Class I wells are the most technologically sophisticated and are used to inject wastes into deep, isolated rock formations below the lowermost underground source of drinking water. Class I wells may inject hazardous waste, non-hazardous industrial waste, or municipal wastewater. Class II wells are typically used by the oil and gas industry to inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons.
volatile organic compound (VOC)	Gases and vapors, such as benzene, released by petroleum refineries, natural gas drilling, petrochemical plants, plastics manufacturing, and the distribution and use of gasoline. VOCs include carcinogens and chemicals that react with sunlight and nitrogen oxides to form ground-level ozone, a component of smog.
water recycling	Collection of frac flowback or produced water and treating the fluid for beneficial use that include hydraulic fracturing, agriculture, or release to streams.
well completion	Well completion incorporates the steps taken to transform a drilled well into a producing one. These steps usually include casing, cementing, perforating, gravel packing, and installing a production tree.
well head	The assembly of fittings and valve equipment used for producing a well and maintaining surface control of a well.
wet gas	Natural gas with significant natural gas liquid components. Also sometimes called rich gas.
workover	Work performed in a well after its completion in an effort to secure production where there has been none, restore production that has ceased, or increase production. Workovers for unconventional wells involve re-fracturing (re-stimulation).

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Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study

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[1] The multispecies analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory (BAO) in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and non-methane hydrocarbons (propane, n-butane, i-pentane, n-pentane and benzene) around BAO, a pilot study involving automobile-based surveys was carried out during the summer of 2008. A mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the alkane ratios we observe in air masses impacted by oil and gas operations in northeastern Colorado. Using the WRAP Phase III inventory of total volatile organic compound (VOC) emissions from oil and gas exploration, production and processing, together with flashing and venting emission speciation profiles provided by State agencies or the oil and gas industry, we derive a range of bottom-up speciated emissions for Weld County in 2008. We use the observed ambient molar ratios and flashing and venting emissions data to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. Our analysis suggests that the emissions of the species we measured are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two.

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1. Introduction

[2] Since 2004, the National Oceanic and Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) has increased its measurement network density over North America, with continuous carbon dioxide (CO_2) and carbon monoxide (CO) measurements and daily collection of discrete air samples at a network of tall towers (A. E. Andrews et al., manuscript in preparation, 2012) and bi-weekly discrete air sampling along vertical aircraft profiles (C. Sweeney et al., manuscript in preparation, 2012). Close to 60 chemical species or isotopes are measured in the discrete air samples, including long-lived greenhouse gases (GHGs) such as CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), tropospheric ozone precursors such as CO and several volatile organic compounds (VOCs), and stratospheric-ozone-depleting substances. The NOAA multispecies regional data set provides unique information on how important atmospheric trace gases vary in space and time over the continent, and it can be used to quantify how different processes contribute to GHG burdens and/or affect regional air quality.

[3] In this study we focus our analysis on a very strong alkane atmospheric signature observed downwind of the Denver-Julesburg Fossil Fuel Basin (DJB) in the Colorado Northern Front Range (Figure 1 and auxiliary material

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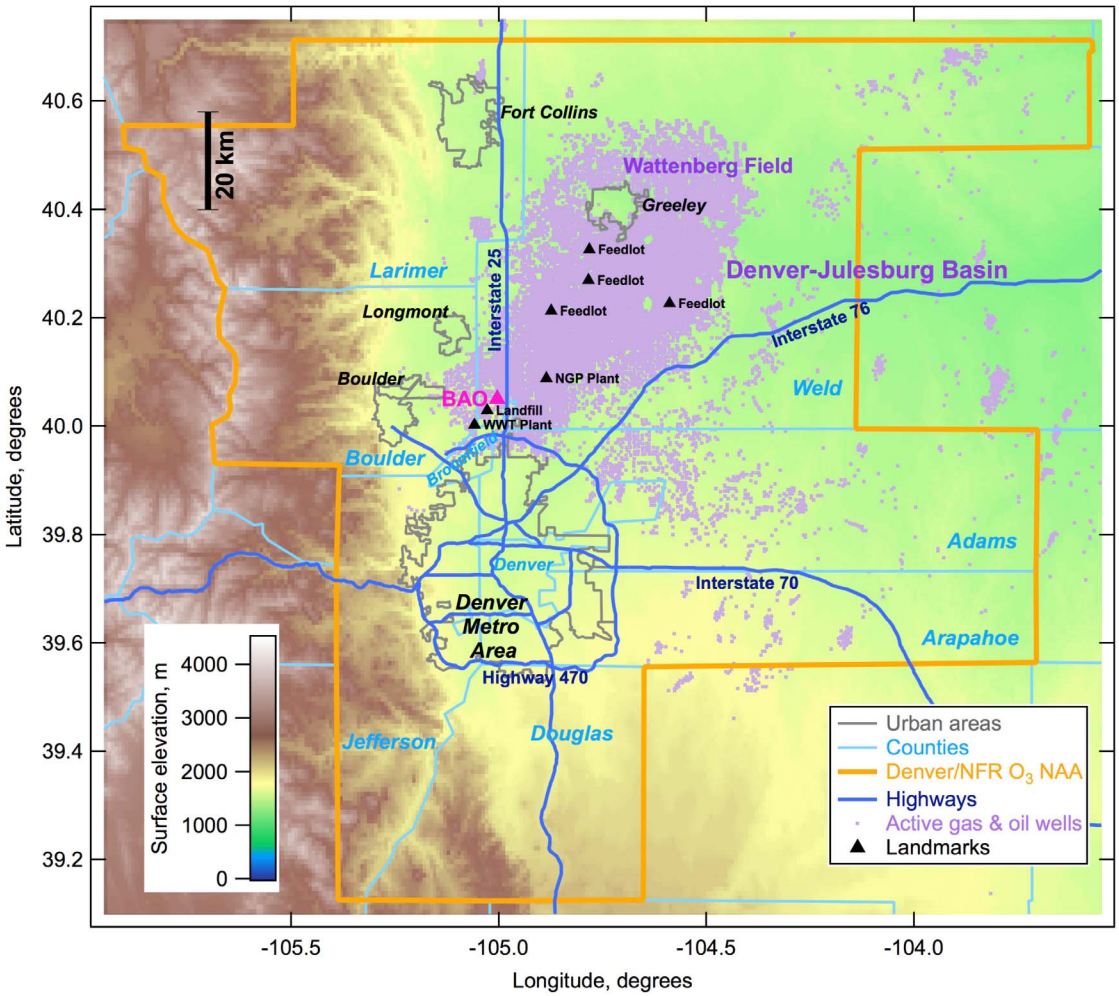

Figure 1. Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, based on COGCC well data). Also shown are the locations of landmarks used in the study, including selected point sources (NGP Plant = natural gas processing plant, WWT Plant = Lafayette wastewater treatment plant).

Figure S1).[1] In 2008, the DJB was home to over 20,000 active natural gas and condensate wells. Over 90% of the production in 2008 came from tight gas formations.

[4] A few recent studies have looked at the impact of oil and gas operations on air composition at the local and regional scales in North America. *Katzenstein et al.* [2003] reported results of two intensive surface air discrete sampling efforts over the Anadarko Fossil Fuel Basin in the southwestern United States in 2002. Their analysis revealed substantial regional atmospheric CH_4 and non-methane hydrocarbon (NMHC) pollution over parts of Texas, Oklahoma, and Kansas, which they attributed to emissions from the oil and gas industry operations. More recently, *Schnell et al.* [2009] observed very high wintertime ozone levels in the vicinity of the Jonah-Pinedale Anticline natural gas field in western Wyoming. *Ryerson et al.* [2003], *Wert et al.* [2003], *de Gouw et al.* [2009] and *Mellqvist et al.* [2010] reported elevated emissions of alkenes from petrochemical plants and refineries in the Houston area and studied their contribution to ozone formation. *Simpson et al.* [2010] present an extensive analysis of atmospheric mixing ratios for a long list of trace gases over oil sands mining operations in Alberta during one flight of the 2008 Arctic Research of the Composition of the Troposphere from Aircraft and Satellites campaign. Our study distinguishes itself from previous ones by the fact that it relies substantially on the analysis of daily air samples collected at a single tall-tower monitoring site between August 2007 and April 2010.

[5] Colorado has a long history of fossil fuel extraction [*Scamehorn*, 2002]. Colorado natural gas production has been increasing since the 1980s, and its share of national production jumped from 3% in 2000 to 5.4% in 2008. 1.3% of the nationally produced oil in 2008 also came from Colorado, primarily from the DJB in northeastern Colorado and from the Piceance Basin in western Colorado. As of

[1]Auxiliary materials are available in the HTML. doi:10.1029/2011JD016360.

2004, Colorado also contained 43 natural gas processing plants, representing 3.5% of the conterminous U.S. processing capacity [*U.S. Energy Information Administration* (*EIA*), 2006], and two oil refineries, located in Commerce City, in Adams County just north of Denver.

[6] Emissions management requirements for both air quality and climate-relevant gases have led the state of Colorado to build detailed baseline emissions inventories for ozone precursors, including volatile organic compounds (VOCs), and for GHGs. Since 2004, a large fraction of the Colorado Northern Front Range, including Weld County and the Denver metropolitan area, has been in violation of the 8-h ozone national ambient air quality standard [*Colorado Department of Public Health and Environment* (*CDPHE*), 2008]. In December 2007, the Denver and Colorado Northern Front Range (DNFR) region was officially designated as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard (see area encompassed by golden boundary in Figure 1). At the end of 2007, Colorado also adopted a Climate Action Plan, which sets greenhouse gas emissions reduction targets for the state [*Ritter*, 2007].

[7] Methane, a strong greenhouse gas with a global warming potential (GWP) of 25 over a 100 yr time horizon [*Intergovernmental Panel on Climate Change*, 2007], accounts for a significant fraction of Colorado GHG emissions, estimated at 14% in 2005 (*Strait et al.* [2007] and auxiliary material Table S1; note that in this report, the oil and gas industry CH_4 emission estimates were calculated with the EPA State Greenhouse Gas Inventory Tool). The natural gas industry (including exploration, production, processing, transmission and distribution) is the single largest source of CH_4 in the state of Colorado (estimated at 238 Gg/yr or ktonnes/yr), followed closely by coal mining (233 Gg/yr); note that all operating surface and underground coal mines are now in western Colorado. Emission estimates for oil production operations in the state were much lower, at 9.5 Gg/yr, than those from gas production. In 2005, Weld County represented 16.5% of the state's natural gas production and 51% of the state crude oil/ natural gas condensate production (auxiliary material Table S2). Scaling the state's total CH_4 emission estimates from *Strait et al.* [2007], rough estimates for the 2005 CH_4 source from natural gas production and processing operations and from natural gas condensate/oil production in Weld County are 19.6 Gg and 4.8 Gg, respectively. It is important to stress here that there are large uncertainties associated with these inventory-derived estimates.

[8] Other important sources of CH_4 in the state include large open-air cattle feedlots, landfills, wastewater treatment facilities, forest fires, and agriculture waste burning, which are all difficult to quantify. 2005 state total CH_4 emissions from enteric fermentation and manure management were estimated at 143 and 48 Gg/yr, respectively [*Strait et al.*, 2007]; this combined source is of comparable magnitude to the estimate from natural gas systems. On-road transportation is not a substantial source of methane [*Nam et al.*, 2004].

[9] In 2006, forty percent of the DNFR NAA's total anthropogenic VOC emissions were estimated to be due to oil and gas operations [*CDPHE*, 2008]. Over the past few years, the State of Colorado has adopted more stringent VOC emission controls for oil and gas exploration and processing activities. In 2007, the Independent Petroleum Association of Mountain States (IPAMS, now Western Energy Alliance), in conjunction with the Western Regional Air Partnership (WRAP), funded a working group to build a state-of-the-knowledge process-based inventory of total VOC and NOx sources involved in oil and gas exploration, production and gathering activities for the western United State's fossil fuel basins, hereafter referred to as the WRAP Phase III effort (http://www.wrapair.org/forums/ogwg/index.html). Most of the oil and gas production in the DJB is concentrated in Weld County. Large and small condensate storage tanks in the County are estimated to be the largest VOC fossil fuel production source category (59% and 9% respectively), followed by pneumatic devices (valve controllers) and unpermitted fugitives emissions (13% and 9% respectively). A detailed breakdown of the WRAP oil and gas source contributions is shown in auxiliary material Figure S2 for 2006 emissions and projected 2010 emissions [*Bar-Ilan et al.*, 2008a, 2008b]. The EPA NEI 2005 for Weld County, used until recently by most air quality modelers, did not include VOC sources from oil and natural gas operations (auxiliary material Table S3).

[10] Benzene (C_6H_6) is a known human carcinogen and it is one of the 188 hazardous air pollutants (HAPs) tracked by the EPA National Air Toxics Assessment (NATA). Benzene, like VOCs and CH_4, can be released at many different stages of oil and gas production and processing. Natural gas itself can contain varying amounts of aromatic hydrocarbons, including C_6H_6 [*U. S. Environmental Protection Agency* (*EPA*), 1998]. Natural gas associated with oil production (such sources are located in several places around the DJB) usually has higher C_6H_6 levels [*Burns*, 1999] than non-associated natural gas. Glycol dehydrators used at wells and processing facilities to remove water from pumped natural gas can vent large amounts of C_6H_6 to the atmosphere when the glycol undergoes regeneration [*EPA*, 1998]. Condensate tanks, venting and flaring at the wellheads, compressors, processing plants, and engine exhaust are also known sources of C_6H_6 [*EPA*, 1998]. C_6H_6 can also be present in the liquids used for fracturing wells [*EPA*, 2004].

[11] In this paper, we focus on describing and interpreting the measured variability in CH_4 and C_{3-5} alkanes observed in the Colorado Northern Front Range. We use data from daily air samples collected at a NOAA tall tower located in Weld County as well as continuous CH_4 observations and discrete targeted samples from an intensive mobile sampling campaign in the Colorado Northern Front Range. These atmospheric measurements are then used together with other emissions data sets to provide an independent view of methane and non-methane hydrocarbon emissions inventory results.

[12] The paper is organized as follows. Section 2 describes the study design and sampling methods. Section 3 presents results from the tall tower and the Mobile Lab surveys, in particular the strong correlation among the various alkanes measured. Based on the multispecies analysis in the discrete air samples, we were able to identify two major sources of C_6H_6 in Weld County. In section 4.1 we discuss the results and in section 4.2 we compare the observed ambient molar ratios with other relevant data sets, including raw natural gas composition data from 77 gas wells in the DJB. The last discussion section 4.3, is an attempt to shed new light on

Table 1. Locations of a Subset of the NOAA ESRL Towers and Aircraft Profile Sites Used in This Study[a]

Site Code	City	State	Latitude (°N)	Longitude (°E)	Elevation (Meters Above Sea Level)	Sampling Height (Meters Above Ground)
BAO	Erie	Colorado	40.05	105.01	1584	300
LEF	Park Falls	Wisconsin	45.93	90.27	472	396
NWF	Niwot Ridge	Colorado	40.03	105.55	3050	23
STR	San Francisco	California	37.755	122.45	254	232
WGC	Walnut Grove	California	38.26	121.49	0	91
WKT	Moody	Texas	31.32	97.33	251	457
SGP[b]	Southern Great Plains	Oklahoma	36.80	97.50	314	<650

[a]STR and WGC in Northern California are collaborations with Department of Energy Environmental Energy Technologies Division at Lawrence Berkeley National Laboratory (PI: Marc Fischer). The last column gives the altitudes of the quasi-daily flask air samples used in this study. We use midday data for all sites, but at Niwot Ridge Forest we used nighttime data to capture background air from summertime downslope flow. We also show the location information of SGP, a NOAA ESRL aircraft site in north central Oklahoma, for which we used samples taken below 650 m altitude.
[b]Aircraft discrete air samples.

methane and VOC emission estimates from oil and gas operations in Weld County. We first describe how we derived speciated bottom-up emission estimates based on the WRAP Phase III total VOC emission inventories for counties in the DJB. We then used (1) an average ambient propane-to-methane molar ratio, (2) a set of bottom-up estimates of propane and methane flashing emissions in Weld County and (3) three different estimates of the propane-to-methane molar ratio for the raw gas leaks to build top-down methane and propane emission scenarios for venting sources in the county. We also scaled the top-down propane (C_3H_8) estimates with the observed ambient alkane ratios to calculate top-down emission estimates for n-butane (n-C_4H_{10}), i- and n-pentane (i-C_5H_{12}, n-C_5H_{12}), and benzene. We summarize our main conclusions in section 5.

2. The Front Range Emissions Study: Sampling Strategy, Instrumentation, and Sample Analysis

2.1. Overall Experimental Design

[13] The Colorado Northern Front Range study was a pilot project to design and test a new measurement strategy to characterize GHG emissions at the regional level. The anchor of the study was a 300-m tall tower located in Weld County, 25 km east-northeast of Boulder and 35 km north of Denver, called the Boulder Atmospheric Observatory (BAO) [40.05°N, 105.01°W; base of tower at 1584 m above sea level] (Figure 1). The BAO is situated on the southwestern edge of the DJB. A large landfill and a wastewater treatment plant are located a few kilometers southwest of BAO. Interstate 25, a major highway going through Denver, runs in a north-south direction 2 km east of the site. Both continuous and discrete air sampling have been conducted at BAO since 2007.

[14] To put the BAO air samples into a larger regional context and to better understand the sources that impacted the discrete air samples, we made automobile-based on-road air sampling surveys around the Colorado Northern Front Range in June and July 2008 with an instrumented "Mobile Lab" and the same discrete sampling apparatus used at all the NOAA towers and aircraft sampling sites.

2.2. BAO and Other NOAA Cooperative Tall Towers

[15] The BAO tall tower has been used as a research facility of boundary layer dynamics since the 1970s [*Kaimal and Gaynor*, 1983]. The BAO tower was instrumented by the NOAA ESRL Global Monitoring Division (GMD) in Boulder in April 2007, with sampling by a quasi-continuous CO_2 non-dispersive infrared sensor and a CO Gas Filter Correlation instrument, both oscillating between three intake levels (22, 100 and 300 m above ground level) (Andrews et al., manuscript in preparation, 2012). Two continuous ozone UV-absorption instruments have also been deployed to monitor ozone at the surface and at the 300-m level.

[16] The tower is equipped to collect discrete air samples from the 300-m level using a programmable compressor package (PCP) and a programmable flasks package (PFP) described later in section 2.4. Since August 2007 one or two air samples have been taken approximately daily in glass flasks using PFPs and a PCP. The air samples are brought back to GMD for analysis on three different systems to measure a series of compounds, including methane (CH_4, also referred to as C_1), CO, propane (C_3H_8, also referred to as C_3), n-butane (n-C_4H_{10}, nC_4), isopentane (i-C_5H_{12}, iC_5), n-pentane (n-C_5H_{12}, nC_5), acetylene (C_2H_2), benzene, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Ethane and i-butane were not measured.

[17] In this study, we use the results from the NOAA GMD multispecies analysis of air samples collected midday at the 300-m level together with 30- second wind speed and direction measured at 300-m. 30-min averages of the wind speed and direction prior to the collection time of each flask are used to separate samples of air masses coming from three different geographic sectors: the North and East (NE sector), where the majority of the DJB oil and gas wells are located; the South (S sector), mostly influenced by the Denver metropolitan area; and the West (W sector), with relatively cleaner air.

[18] In 2008, NOAA and its collaborators were operating a regional air sampling network of eight towers and 18 aircraft profiling sites located across the continental U.S. employing in situ measurements (most towers) and flask sampling protocols (towers and aircraft sites) that were similar to those used at BAO. Median mixing ratios for several alkanes, benzene, acetylene, and carbon monoxide from BAO and a subset of five other NOAA towers and from one aircraft site are presented in the Results (section 3). Table 1 provides the three letter codes used for each sampling site, their locations and sampling heights. STR is located in San Francisco. WGC is located 34 km south of downtown Sacramento in California's Central Valley where

Table 2. List of the Front Range Mobile Lab Measurement and Flasks Sampling Surveys[a]

Road Survey Number	Road Survey Date	Geographical Area/Target Sources	Measurements/Sampling Technique
1	June 4	Boulder	12 flasks
2	June 11	Boulder + Foothills	12 flasks
3	June 19	NOAA-Longmont-Fort Collins- Greeley (Oil and Gas Drilling, Feedlots)	24 flasks
4	July 1	NOAA - Denver	12 flasks
5	July 9	Around Denver	Picarro
6	July 14	NOAA - Greeley	12 flasks
7	July 15	NOAA-Greeley	Picarro
8	July 25	BAO surroundings - Natural Gas Processing Plant - Feedlot	Picarro + 8 flasks
9	July 31	"Regional" CH_4 enhancements, Landfill, Corn field	Picarro + 12 flasks

[a]Some trips (1, 2, 3, 4, 6) sampled air using the flask only. Surveys 5 and 7 used only the continuous analyzers on the Mobile Lab with no discrete flask collection. The last two trips targeted flask sampling close to known point or area sources based on the continuous methane measurement display in the Mobile Lab.

agriculture is the main economic sector. Irrigated crop fields and feedlots contribute to the higher CH_4 observed at WGC. The LEF tower in northern Wisconsin is in the middle of the Chequamegon National Forest which is a mix of temperate/boreal forest and lowlands/wetlands [*Werner et al.*, 2003]. Air samples from NWF (surface elevation 3050 m), in the Colorado Rocky Mountains, mostly reflect relatively unpolluted air from the free troposphere. The 457m tall Texas tower (WKT) is located between Dallas/Fort Worth and Austin. It often samples air masses from the surrounding metropolitan areas. In summer especially, it also detects air masses with cleaner background levels arriving from the Gulf of Mexico. The SGP NOAA aircraft sampling site (Sweeney et al., manuscript in preparation, 2012; http://www.esrl.noaa.gov/gmd/ccgg/aircraft/) in northern Oklahoma is also used in the comparison study. At each aircraft site, twelve discrete air samples are collected at specified altitudes on a weekly or biweekly basis. Oklahoma is the fourth largest state for natural gas production in the USA (EIA, Natural gas navigator, 2008, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm) and one would expect to observe signatures of oil and gas drilling operations at both SGP and BAO. Additional information on the tower and aircraft programs is available at http://www.esrl.noaa.gov/gmd/ccgg/. Median summer mixing ratios for several alkanes, C_2H_2, C_6H_6 and CO are presented in the Results section.

2.3. Mobile Sampling

[19] Two mobile sampling strategies were employed during this study. The first, the Mobile Lab, consisted of a fast response CO_2 and CH_4 analyzer (Picarro, Inc.), a CO gas-filter correlation instrument from Thermo Environmental, Inc., an O_3 UV-absorption analyzer from 2B Technologies and a Global Positioning System (GPS) unit. All were installed onboard a vehicle. A set of 3 parallel inlets attached to a rack on top of the vehicle brought in outside air from a few meters above the ground to the instruments. Another simpler sampling strategy was to drive around and collect flask samples at predetermined locations in the Front Range region. A summary of the on-road surveys is given in Table 2.

[20] The Mobile Lab's Picarro Envirosense $CO_2/CH_4/H_2O$ analyzer (model G1301, unit CFADS09) employs Wavelength-Scanned Cavity Ring-Down Spectroscopy (WS-CRDS), a time-based measurement utilizing a near-infrared laser to measure a spectral signature of the molecule. CO_2, CH_4, and water vapor were measured at a 5-s sampling rate (0.2 Hz), with a standard deviation of 0.09 ppm in CO_2 and 0.7 ppb for CH_4. The sample was not dried prior to analysis, and the CO_2 and CH_4 mole fractions were corrected for water vapor after the experiment based on laboratory tests. For water mole fractions between 1% and 2.5%, the relative magnitude of the CH_4 correction was quasi-linear, with values between 1 and 2.6%. CO_2 and CH_4 mole fractions were assigned against a reference gas tied to the relevant World Meteorological Organization (WMO) calibration scale. Total measurement uncertainties were 0.1 ppm for CO_2 and 2 ppb for CH_4 (Sweeney et al., manuscript in preparation, 2012). The CO and ozone data from the Mobile Lab are not discussed here. GPS data were also collected in the Mobile Lab at 1 Hz, to allow data from the continuous analyzers to be merged with the location of the vehicle.

[21] The excursions with the flask sampler (PFP) focused on characterizing the concentrations of trace gases in Boulder (June 4 and 11, 2008), the northeastern Front Range (June 19), Denver (July 1) and around oil and gas wells and feedlots in Weld County south of Greeley (July 14) (see Table 2). Up to 24 sampling locations away from direct vehicle emissions were chosen before each drive.

[22] Each Mobile Lab drive lasted from four to six hours, after a ~30 min warm-up on the NOAA campus for the continuous analyzer before switching to battery mode. The first two Mobile Lab drives, which did not include discrete air sampling, were surveys around Denver (July 9) and between Boulder and Greeley (July 15). The last two drives with the Mobile Lab (July 25 and 31) combined in situ measurements with discrete flask sampling to target emissions from specific sources: the quasi-real-time display of the data from the continuous CO_2/CH_4 analyzer was used to collect targeted flask samples at strong CH_4 point sources in the vicinity of BAO. Discrete air samples were always collected upwind of the surveying vehicle and when possible away from major road traffic.

2.4. Chemical Analyses of Flask Samples

[23] Discrete air samples were collected at BAO and during the road surveys with a two-component collection apparatus. One (PCP) includes pumps and batteries, along with an onboard microprocessor to control air sampling. Air was drawn through Teflon tubing attached to an expandable 3-m long fishing pole. The second package (PFP) contained a sampling manifold and twelve cylindrical, 0.7 L, glass flasks of flow-through design, fitted with Teflon O-ring on both

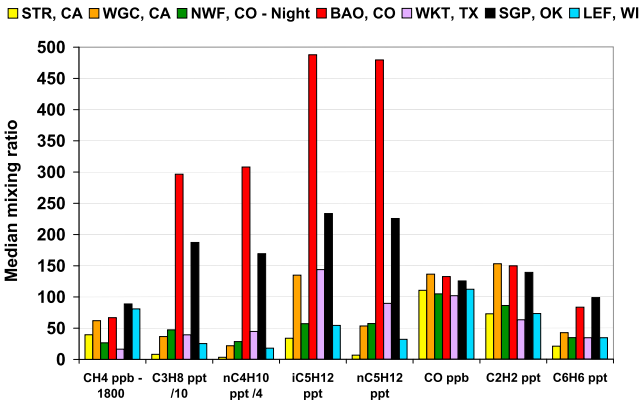

Figure 2. Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June–August (2007–2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly downslope winds. Notice the different units with all columns and the different scaling applied to methane, propane and n-butane.

stopcocks. Before deployment, manifold and flasks were leak-checked then flushed and pressurized to ~1.4 atm with synthetic dry zero-air containing approximately 330 ppm of CO_2 and no detectable CH_4. During sampling, the manifold and flasks were flushed sequentially, at ~5 L min^{-1} for about 1 min and 10 L min^{-1} for about 3 min respectively, before the flasks were pressurized to 2.7 atm. Upon returning to the NOAA lab, the PFP manifold was leak-checked and metadata recorded by the PFP during the flushing and sampling procedures were read to verify the integrity of each air sample collected. In case of detected inadequate flushing or filling, the affected air sample is not analyzed.

[24] Samples collected in flasks were analyzed for close to 60 compounds by NOAA GMD (http://www.esrl.noaa.gov/gmd/ccgg/aircraft/analysis.html). In this paper, we focus on eight species: 5 alkanes (CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) as well as CO, C_2H_2 and C_6H_6. CH_4 and CO in each flask were first quantified on one of two nearly identical automated analytical systems (MAGICC 1 and 2). These systems consist of a custom-made gas inlet system, gas-specific analyzers, and system-control software. Our gas inlet systems use a series of stream selection valves to select an air sample or standard gas, pass it through a trap for drying maintained at ~−80°C, and then to an analyzer.

[25] CH_4 was measured by gas chromatography (GC) with flame ionization detection (±1.2 ppb = average repeatability determined as 1 s.d. of ~20 aliquots of natural air measured from a cylinder) [*Dlugokencky et al.*, 1994]. We use the following abbreviations for measured mole fractions: ppm = μmol mol^{-1}, ppb = nmol mol^{-1}, and ppt = pmol mol^{-1}. CO was measured directly by resonance fluorescence at ~150 nm (±0.2 ppb) [*Gerbig et al.*, 1999; *Novelli et al.*, 1998]. All measurements are reported as dry air mole fractions relative to internally consistent calibration scales maintained at NOAA (http://www.esrl.noaa.gov/gmd/ccl/scales.html).

[26] Gas chromatography/mass spectrometric (GC/MS) measurements were also performed on ~200 mL aliquots taken from the flask samples and pre-concentrated with a cryogenic trap at near liquid nitrogen temperatures [*Montzka et al.*, 1993]. Analytes desorbed at ~110°C were then separated by a temperature-programmed GC column (combination 25 m × 0.25 mm DB5 and 30 m × 0.25 mm Gaspro), followed by detection with mass spectrometry by monitoring compound-specific ion mass-to-charge ratios. Flask sample responses were calibrated versus whole air working reference gases which, in turn, are calibrated with respect to gravimetric primary standards (NOAA scales: benzene on NOAA-2006 and all other hydrocarbons (besides CH_4) on NOAA-2008). We used a provisional calibration for n-butane based on a diluted Scott Specialty Gas standard. Total uncertainties for analyses from the GC/MS reported here are <5% (accuracy) for all species except n-C_4H_{10} and C_2H_2, for which the total uncertainty at the time of this study was of the order of 15–20%. Measurement precision as repeatability is generally less than 2% for compounds present at mixing ratios above 10 ppt.

[27] To access the storage stability of the compounds of interest in the PFPs, we conducted storage tests of typically 30 days duration, which is greater than the actual storage time of the samples used in this study. Results for C_2H_2 and C_3H_8 show no statistically significant enhancement or degradation with respect to our "control" (the original test gas tank results) within our analytical uncertainty. For the remaining species, enhancements or losses average less than 3% for the 30 day tests. More information on the quality control of the flask analysis data is available at http://www.esrl.noaa.gov/gmd/ccgg/aircraft/qc.html.

[28] The flask samples were first sent to the GC/MS instrument for hydrocarbons, CFCs, and HFCs before being analyzed for major GHGs. This first step was meant to screen highly polluted samples that could potentially damage the greenhouse gas MAGICC analysis line with concentrations well above "background" levels. The time interval between flask collection and flask analysis spanned between 1 to 11 days for the GC/MS analysis and 3 to 12 days for MAGICC analysis.

3. Results

3.1. BAO Tall Tower: Long-Term Sampling Platform for Regional Emissions

3.1.1. Comparing BAO With Other Sampling Sites in the U.S.

[29] Air samples collected at BAO have a distinct chemical signature (Figure 2), showing enhanced levels of most alkanes (C_3H_8, n-C_4H_{10}, i-C_5H_{12} and n-C_5H_{12}) in comparison to results from other NOAA cooperative tall towers (see summary of site locations in Table 1 and data time series in auxiliary material Figure S1). The midday summer time median mixing ratios for C_3H_8 and n-C_4H_{10} at BAO were at least 6 times higher than those observed at most other tall tower sites. For i-C_5H_{12} and n-C_5H_{12}, the summertime median mixing ratios at BAO were at least 3 times higher than at the other tall towers.

[30] In Figure 2, we show nighttime measurements at the Niwot Ridge Forest tower (NWF) located at a high elevation site on the eastern slopes of the Rocky Mountains, 50 km west of BAO. During the summer nighttime, downslope flow brings clean air to the tower [*Roberts et al.*, 1984]. The median summer mixing ratios at NWF for all the species shown in Figure 2 are much lower than at BAO, as would be expected given the site's remote location.

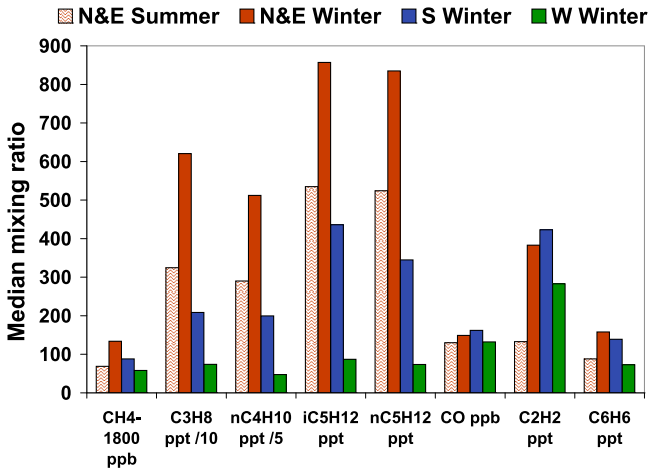

Figure 3. Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-m level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean air. The time span of the data is from August 2007 to April 2010. Summer includes data from June to August and winter includes data from November to April. Due to the small number of data points (<15), we do not show summer values for the S and W wind sectors. Data outside of the 11am-3pm local time window were not used. Notice the different scales used for methane, propane and n-butane. The minimum number of data points used for each wind sector is: NE summer 33, NE winter 89, S winter 65 and W winter 111.

[31] Similarly to BAO, the northern Oklahoma aircraft site, SGP, exhibits high alkane levels in the boundary layer and the highest methane summer median mixing ratio of all sites shown in Figure 2 (1889 ppb at SGP versus 1867 ppb at BAO). As for BAO, SGP is located in an oil- and gas-producing region. Oklahoma, the fourth largest state in terms of natural gas production in the U.S., has a much denser network of interstate and intrastate natural gas pipelines compared to Colorado. *Katzenstein et al.* [2003] documented the spatial extent of alkane plumes around the gas fields of the Anadarko Basin in Texas, Oklahoma, and Kansas during two sampling intensives. The authors estimated that methane emissions from the oil and gas industry in that entire region could be as high as 4–6 Tg CH_4/yr, which is 13–20% of the U.S. total methane emission estimate for year 2005 reported in the latest EPA U.S. GHG Inventory (EPA, Inventory of U.S. Greenhouse Gas emissions and Sinks: 1990–2009, 2011, available at http://www.epa.gov/climatechange/emissions).

[32] Enhancements of CH_4 at BAO are not as striking in comparison to other sites. CH_4 is a long-lived gas destroyed predominantly by its reaction with OH radicals. CH_4 has a background level that varies depending on the location and season [*Dlugokencky et al.*, 1994], making it more difficult to interpret differences in median summer CH_4 mixing ratios at the suite of towers. Since we do not have continuous measurements of CH_4 at any of the towers except WGC, we cannot clearly separate CH_4 enhancements from background variability in samples with levels between 1800 and 1900 ppb if we only look at CH_4 mixing ratios by themselves (see more on this in the next section).

3.1.2. Influence of Different Sources at BAO

3.1.2.1. Median Mixing Ratios in the Three Wind Sectors

[33] To better separate the various sources influencing air sampled at BAO, Figure 3 shows the observed median mixing ratios of several species as a function of prevailing wind direction. For this calculation, we only used samples for which the associated 30-min average wind speed (prior to collection time) was larger than 2.5 m/s. We separated the data into three wind sectors: NE, including winds from the north, northeast and east (wind directions between 345° and 120°); S, including south winds (120° to 240°); and W, including winds from the west (240° to 345°).

[34] For the NE sector, we can further separate summer (June to August) and winter (November to April) data. For the other two wind sectors, only the winter months have enough data points. The species shown in Figure 3 have different photochemical lifetimes [*Parrish et al.*, 1998], and all are shorter-lived in the summer season. This fact, combined with enhanced vertical mixing in the summer, leads to lower mixing ratios in summer than in winter.

[35] Air masses from the NE sector pass over the oil and gas wells in the DJB and exhibit large alkane enhancements. In winter, median mole fractions of C_3-C_5 alkanes are 8 to 11 times higher in air samples from the NE compared to the samples from the W sector, while the median CH_4 value is 76 ppb higher. The NE wind sector also shows the highest median values of C_6H_6, but not CO and C_2H_2.

[36] C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers in air samples from the NE wind sector are much higher than in air samples coming from the Denver metropolitan area in the South wind sector. Besides being influenced by Denver, southern air masses may pass over two operating landfills, the Commerce City oil refineries, and some oil and gas wells (Figure 1). The S sector BAO CO and C_2H_2 mixing ratios are higher than for the other wind sectors, consistent with the higher density of vehicular emission sources [*Harley et al.*, 1992; *Warneke et al.*, 2007; *Baker et al.*, 2008] south of BAO. There are also occasional spikes in CFC-11 and CFC-12 mixing ratios in the S sector (not shown). These are most probably due to leaks from CFC-containing items in the landfills. Air parcels at BAO coming from the east pass over Interstate Highway 25, which could explain some of the high mole fractions observed for vehicle combustion tracers such as CO, C_2H_2, and C_6H_6 in the NE sector data (see more discussion on C_6H_6 and CO in section 4.4 and Figure 4).

[37] The W wind sector has the lowest median mole fractions for all anthropogenic tracers, consistent with a lower density of emission sources west of BAO compared to the other wind sectors. However, the S and W wind sectors do have some data points with high alkane values, and these data will be discussed further below.

3.1.2.2. Strong Alkane Source Signature

[38] To detect if the air sampled at BAO has specific chemical signatures from various sources, we looked at correlation plots for the species shown in Figure 3. Table 3 summarizes the statistics for various tracer correlations for the three different wind sectors. Figure 4 (left) shows correlation plots of some of these BAO species for summer data in the NE wind sector.

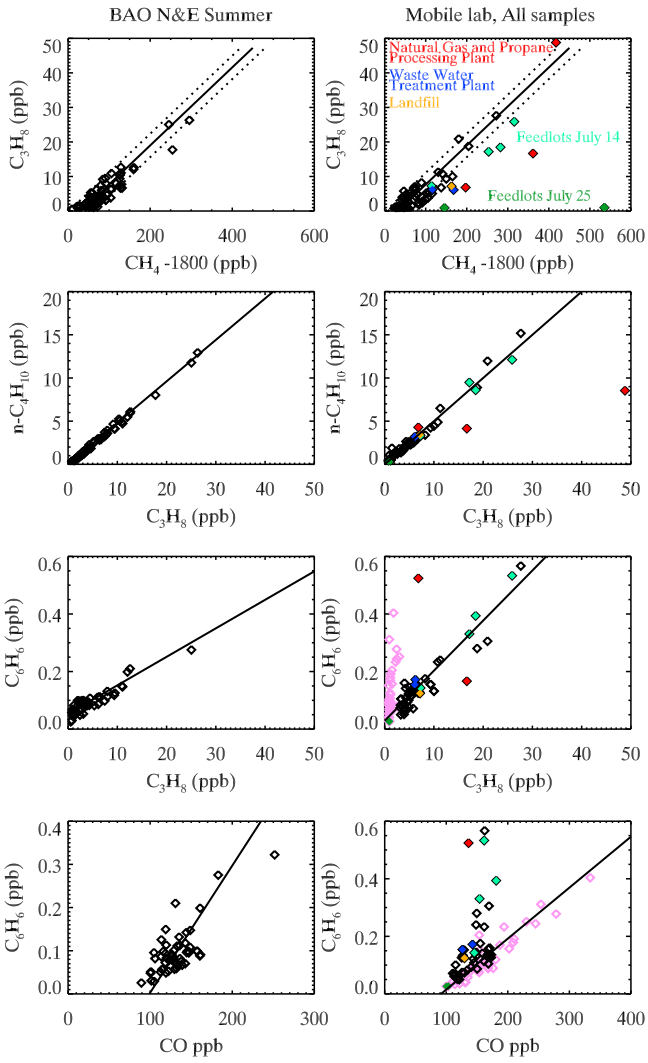

Figure 4. Correlation plots for various species measured in the (left) BAO summertime NE wind sector flask samples and (right) summer 2008 Mobile Lab samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 2009. See also Table 3.

[39] Even though BAO data from the NE winds show the largest alkane mixing ratios (Figure 3), all three sectors exhibit strong correlations between C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers (Table 3). The r^2 values for the correlations between C_3H_8 and n-C_4H_{10} or the C_5H_{12} isomers are over 0.9 for the NE and W sectors. CH_4 is also well correlated with C_3H_8 in the NE wind sector for both seasons. For the NE wind sector BAO summertime data, a min/max range for the C_3H_8/CH_4 slope is 0.099 to 0.109 ppb/ppb.

[40] The tight correlations between the alkanes suggest a common source located in the vicinity of BAO. Since large alkane enhancements are more frequent in the NE wind sector, this common source probably has larger emissions north and east of the tower. This NE wind sector encompasses Interstate Highway 25 and most of the DJB oil and gas wells. The C_3-C_5 alkane mole fractions do not always correlate well with combustion tracers such as C_2H_2 and CO for the BAO NE wind sector (C_{3-5}/CO and C_{3-5}/C_2H_2: $r^2 < 0.3$ for 50 summer samples; C_{3-5}/CO: $r^2 < 0.4$ and C_{3-5}/C_2H_2: $r^2 \sim 0.6$ for 115 winter samples). These results indicate that the source responsible for the elevated alkanes at BAO is not the major source of CO or C_2H_2, which argues against vehicle combustion exhaust as being responsible. Northeastern Colorado is mostly rural with no big cities. The only operating oil refineries in Colorado are in the northern part of the Denver metropolitan area, south of BAO. The main industrial operations in the northeastern Front Range are oil and natural gas exploration and production and natural gas processing and transmission. We therefore hypothesize here that the oil and gas operations in the DJB, as noted earlier in section 2, are a potentially substantial source of alkanes in the region.

3.1.2.3. At Least Two Sources of Benzene in BAO Vicinity

[41] The median winter C_6H_6 mixing ratio at BAO is higher for the NE wind sector compared to the South wind sector, which comprises the Denver metropolitan area. The C_6H_6-to-CO winter correlation is highest for the S and W wind sectors BAO samples ($r^2 = 0.85$ and 0.83 respectively) compared to the NE wind sector data ($r^2 = 0.69$). The C_6H_6-to-CO correlation slope is substantially higher for the NE wind sector data compared to the other two wind sectors, suggesting that there may be a source of benzene in the NE

Table 3. Correlation Slopes and r^2 for Various Species Measured in the BAO Tower Midday Air Flask Samples for Summer (June to August, When More Than 25 Samples Exist) and Winter (November to April) Over the Time Period Spanning August 2007 to April 2010[a]

Sector		BAO North and East						BAO South Winter			BAO West Winter			Mobile Lab Summer		
Season		Summer			Winter											
Molar Ratios y/x	Units	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n
C_3H_8/ CH_4	ppb/ ppb	**0.104 ± 0.005**	0.85	81	**0.105 ± 0.004**	0.90	115	0.079 ±0.008	0.53	130	**0.085 ± 0.005**	0.73	148	**0.095 ± 0.007**	0.76	77
nC_4H_{10}/ C_3H_8	ppb/ ppb	**0.447 ± 0.013**	1.00	81	**0.435 ± 0.005**	1.0	120	**0.449 ± 0.011**	0.98	131	**0.434 ± 0.006**	1.00	151	**0.490 ± 0.011**	1.00	85
iC_5H_{12}/ C_3H_8	ppb/ ppb	**0.14 1 ± 0.004**	1.00	81	**0.134 ± 0.004**	0.98	120	**0.142 ± 0.009**	0.81	121	**0.130 ± 0.004**	0.94	151	**0.185 ± 0.011**	0.81	85
nC_5H_{12}/ C_3H_8	ppb/ ppb	**0.150 ± 0.003**	1.00	81	**0.136 ± 0.004**	0.98	120	**0.142 ± 0.006**	0.90	131	**0.133 ± 0.003**	0.91	151	**0.186 ± 0.008**	0.92	85
C_6H_6/ C_3H_8	ppt/ ppb	10.1 ± 1.2	0.67	49	**8.2 ± 0.5**	0.79	117	-	0.33	130	-	0.39	150	**17.9 ± 1.1**	0.95	46
C_6H_6/ CO	ppt/ ppb	2.89 ± 0.40	0.58	53	3.18 ± 0.24	0.69	112	**1.57 ± 0.08**	0.85	123	**1.81 ± 0.08**	0.83	148	**1.82 ± 0.12**	0.89	39
C_2H_2/ CO	ppt/ ppb	**3.15 ± 0.33**	0.85	81	**7.51 ± 0.39**	0.85	100	**5.03 ± 0.17**	0.92	110	**5.85 ± 0.25**	0.86	131	**4.32 ± 0.28**	0.89	39
C_6H_6/ C_2H_2	ppt/ ppt	0.51 ± 0.09	0.55	50	**0.34 ± 0.02**	0.90	103	**0.27 ± 0.02**	0.90	111	**0.32 ± 0.02**	0.96	132	**0.37 ± 0.04**	0.75	39

[a]The three wind sectors used in Figure 3 are also used here with a 30-min average wind speed threshold of 2.5 m/s. Also shown are the slopes derived from flask samples collected by the Mobile Lab in summer 2008. The slope is in bold when r^2 is higher than 0.7 and the slope is not shown when r^2 is less than 0.4. The number of data points (n) used for the slope and r^2 calculations are provided. All slope units are ppb/ppb, except for C_6H_6/C_3H_8, C_6H_6/CO and C_2H_2/CO, which are in ppt/ppb. We used the IDL routine linmix_err.pro for the calculations with the following random measurement errors: 2ppb for CH_4 and CO and 5% for C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}, C_2H_2, and C_6H_6.

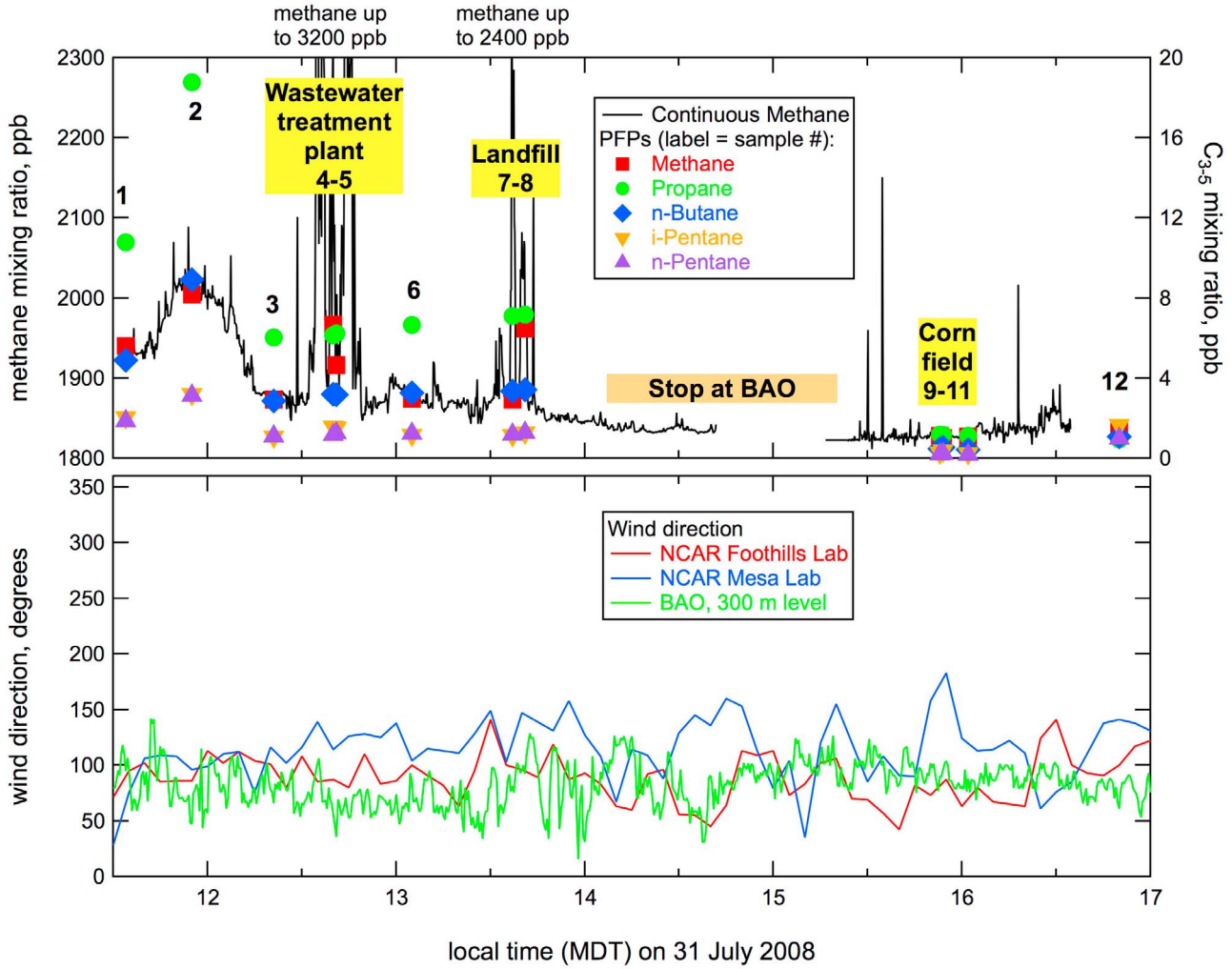

Figure 5. (top) Time series of the continuous methane measurements from Mobile Lab Survey 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in more noisy data for the alkanes and the CFCs ($\sigma < 10\%$ instead of 5%). However, the amplitudes of the C_{3-5} alkane signals are much larger than the noise here. The methane mixing ratio scale is shown on the left hand vertical axis. For all other alkanes, refer to the right hand vertical axis. (bottom) Time series of wind directions at the NCAR Foothills and Mesa Laboratories in Boulder (see Figure 6 for locations) and from the 300-m level at the BAO on July 31, 2008.

that is not a significant source of CO. The C_6H_6-to-C_2H_2 correlation slope is slightly higher for the NE wind sector data compared to the other two wind sectors. C_6H_6 in the BAO data from the NE wind sector correlates more strongly with C_3H_8 than with CO. The C_6H_6-to-C_3H_8 summer correlation slope for the NE wind sector is 10.1 $\pm$ 1.2 ppt/ppb ($r^2 = 0.67$).

[42] For the S and W wind sectors BAO data, the C_6H_6-to-C_2H_2 (0.27 - 0.32 ppt/ppt) and C_6H_6-to-CO (1.57 - 1.81 ppt/ppb) slopes are larger than observed emissions ratios for the Boston/New York City area in 2004: 0.171 ppt/ppt for C_6H_6-to-C_2H_2 ratio and 0.617 ppt/ppb for C_6H_6-to-CO ratio [*Warneke et al.*, 2007]. *Baker et al.* [2008] report an atmospheric molar C_6H_6-to-CO ratio of 0.9 ppt/ppb for Denver in summer 2004, which is in between the Boston/NYC emissions ratio value reported by *Warneke et al.* [2007] and the BAO S and W wind sectors correlation slopes.

[43] The analysis of the BAO C_6H_6 data suggests the existence of at least two distinct C_6H_6 sources in the vicinity of BAO: an urban source related mainly to mobile emissions, and a common source of alkanes and C_6H_6 concentrated in northeastern Colorado. We discuss C_6H_6 correlations and sources in more detail in section 4.4.

3.2. On-Road Surveys: Tracking Point and Area Source Chemical Signatures

[44] Road surveys with flask sampling and the Mobile Lab with the fast-response CH_4 analyzer were carried out in June–July 2008 (Table 2). The extensive chemical analysis of air samples collected in the Front Range provides a snapshot of a broader chemical composition of the regional boundary layer during the time of the study. The Mobile Lab surveys around the Front Range using the in situ CH_4 analyzer allowed us to detect large-scale plumes with long-

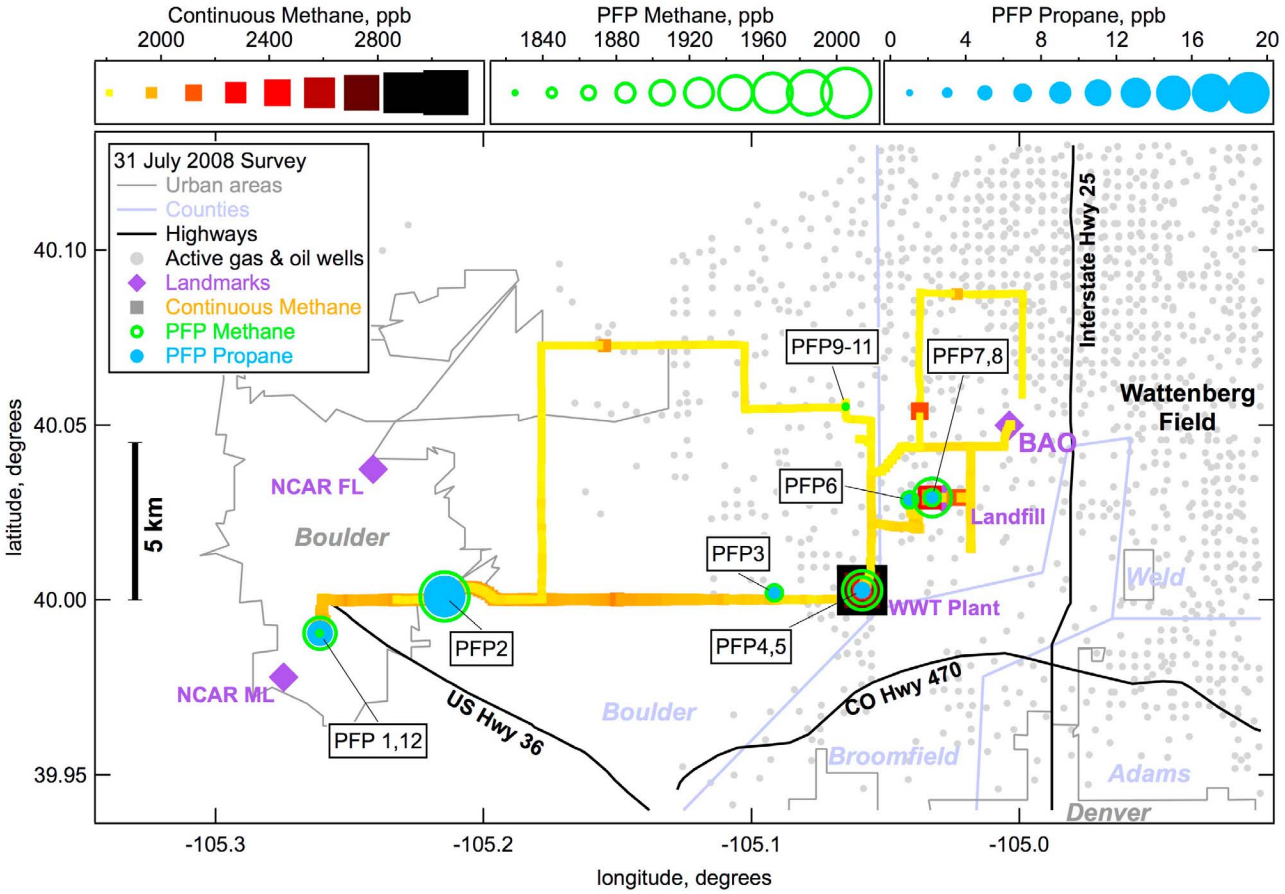

Figure 6. Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey 9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (squares, green circles) and flask propane (blue circles). The labels indicate the flask sample number (also shown in the time series in Figure 5). NCAR = National Center for Atmospheric Research, FL = NCAR Foothills Laboratory, ML = NCAR Mesa Laboratory, WWT Plant = Lafayette wastewater treatment plant.

lasting enhancements of CH_4 mixing ratios as well as small-scale plumes associated with local CH_4 point sources. In the last two Mobile Lab surveys (surveys 8 and 9), we combined the monitoring of the continuous CH_4 analyzer with targeted flask sampling, using the CH_4 data to decide when to collect flask samples in and out of plumes.

[45] The regional background CH_4 mixing ratio at the surface (interpreted here as the lowest methane level sustained for ~10 min or more) was between 1800 ppb and 1840 ppb for most surveys. Some of the highest "instantaneous" CH_4 mixing ratios measured during the Mobile Lab surveys were: 3166 ppb at a wastewater treatment plant, 2329 ppb at a landfill, 2825 ppb at a feedlot near Dacono, over 7000 ppb close to a feedlot waste pond near Greeley, and 4709 ppb at a large natural gas processing and propane plant in Fort Lupton (Figure 1).

[46] The analysis of the summer 2008 intensive data suggests that regional scale mixing ratio enhancements of CH_4 and other alkanes are not rare events in the Colorado Northern Front Range airshed. Their occurrence and extent depends on both emissions and surface wind conditions, which are quite variable and difficult to predict in this area. During the Mobile Lab road surveys, the high-frequency measurements of CO_2 and CH_4 did not exhibit any correlation. Unlike CO_2, the CH_4 enhancements were not related to on-road emissions. Below we present two examples of regional enhancements of CH_4 observed during the Front Range Mobile Lab surveys.

3.2.1. Survey 9: C_{3-5} Alkane Levels Follow Large-Scale Changes in Methane

[47] Figure 5 shows a time series of the continuous CH_4 mixing ratio data and alkane mixing ratios measured in twelve flask samples collected during the Front Range Mobile Lab survey on 31 July 2008 (flasks 1 to 12, sampled sequentially as shown in Figure 6). The wind direction on that day was from the ENE or E at the NCAR Foothills Lab and BAO tower. The Mobile Lab left the NOAA campus in Boulder around 11:40 A.M. and measured increasing CH_4 levels going east toward the BAO tower (Figure 6). An air sample was collected close to the peak of the CH_4 broad enhancement centered around 11:55 A.M. The CH_4 mixing ratio then decreased over the next 25 min and reached a local minimum close to 1875 ppb. The CH_4 level stayed around 1875 ppb for over one hour and then decreased again, more slowly this time, to ~1830 ppb over the next two hours.

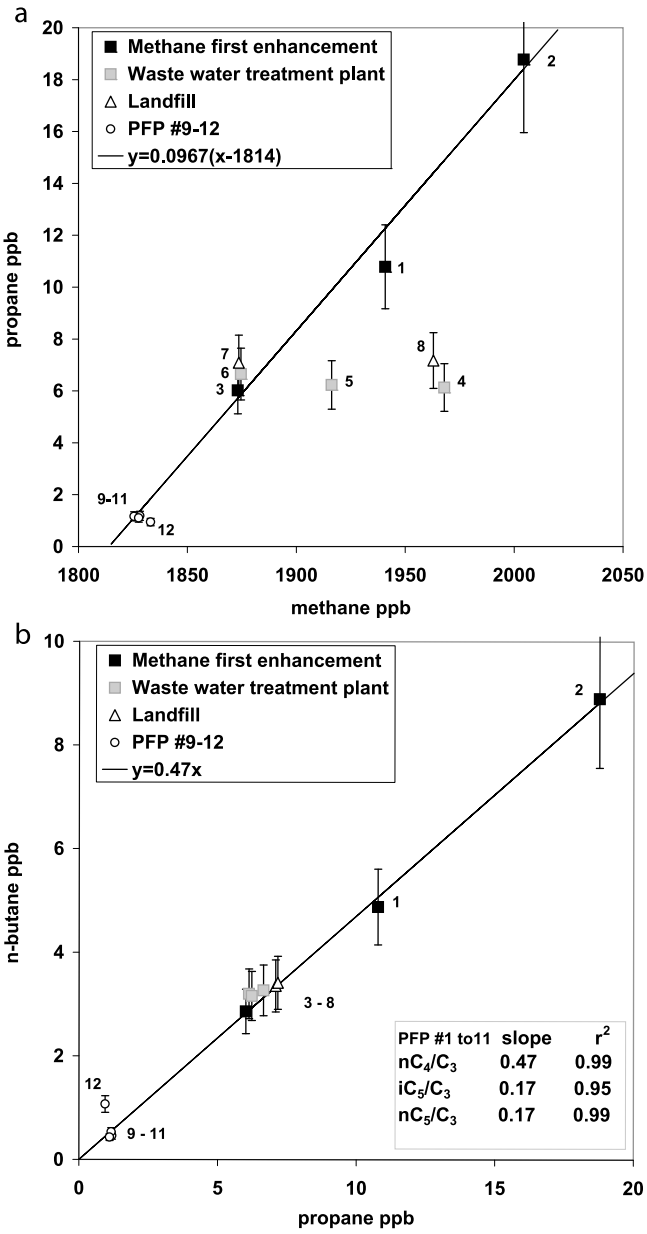

Figure 7. (a) Propane versus methane mixing ratios for air samples collected during Survey 9 on July 31, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 7a shows the correlation line for samples not impacted by local sources of methane (all flasks except 4, 5, 8, and 12). The black line in Figure 7b shows the correlation line for all samples except flask 12. The flask sample number is shown next to each data point. The twelve samples were filled sequentially (see Figure 6).

[48] Flasks 1 to 3 were collected before, at the peak, and immediately after the broad CH_4 feature between 11:40 and 12:15. Flasks 4 and 5 were sampled close to a wastewater treatment plant and flasks 7 to 8 were sampled in a landfill. The in situ measurements showed that CH_4 was still elevated above background as these samples were collected. After a 90-min stop at BAO to recharge the Mobile Lab UPS batteries, flasks 9 to 11 were collected in a corn field while the in situ measurements showed lower CH_4 levels. The last flask sample was collected on the NOAA campus just before 17:00 MDT, about 5.5 h after the first flask sample was collected. The flask samples were always collected upwind of the Mobile Lab car exhaust.

[49] Sharp spikes in the continuous CH_4 data reflect local point sources (wastewater treatment plant, landfill). The highly variable signals in both the continuous and discrete CH_4 close to these sources are driven by the spatial heterogeneity of the CH_4 emissions and variations in wind speed and direction. Broader enhancements in the continuous CH_4 data reflect larger (regional) plumes. The last flask (12) sampled at NOAA has much higher levels of combustion tracers (CO, C_2H_2, C_6H_6) than the other samples.

[50] Figure 7 shows correlation plots for C_3H_8 versus CH_4 and n-C_4H_{10} versus C_3H_8 in the 12 flasks taken on 31 July. Air samples not directly influenced by identified point sources (flasks 1–3, 6–7, 9–12) show a very strong correlation between the various measured alkanes. Using the data from the air samples not directly influenced by identified point sources (flasks 1–3, 6–7, 9–12), we derive a C_3H_8-to-CH_4 (C_3/C_1) mixing ratio slope of 0.097 $\pm$ 0.005 ppb/ppb (Figure 7a). This slope is very similar to the one observed for the summertime NE wind sector data at BAO (0.104 $\pm$ 0.005; Table 3). Three air samples collected downwind of the wastewater treatment plant and the landfill (flasks 4–5 and 8) are off the C_3H_8-to-CH_4 correlation line and have higher CH_4 than air samples collected nearby but not under the influence of these local CH_4 sources (flasks 3 and 6). Flask 8 also has elevated CFC-11 (310 ppt) compared to the other samples collected that day (<255 ppt), probably related to leaks from old appliances buried in the landfill.

[51] The C_3-C_5 alkane mixing ratios in samples collected on 31 July are tightly correlated for flasks 1 to 11 with $r^2 > 0.95$ (Figure 7b). As concluded for the BAO alkane mixing ratio enhancements earlier, this tight correlation suggests that the non-methane alkanes measured during the surveys are coming from the same source types. The nC_4/C_3 correlation slope on 31 July (0.47 ppb/ppb; flasks 1–11) is similar to the summer slope in the BAO NE samples (0.45 ppb/ppb), while the 31 July iC_5/C_3 and nC_5/C_3 slopes are slightly higher (0.17 and 0.17 ppb/ppb, respectively) than for BAO (0.14 and 0.15 ppb/ppb, respectively).

3.2.2. Survey 6: Alkane Enhancements in the Denver-Julesburg Oil and Gas Production Zone and Cattle Feedlot Contributions to Methane

[52] The flask-sampling-only mobile survey on 14 July 2008 focused on the agricultural and oil and gas drilling region south of Greeley. Eleven of the twelve air samples collected on 14 July were taken over the Denver-Julesburg Basin (flasks 2–12 in auxiliary material Figure S3). Figure 8a shows a correlation plot of C_3H_8 versus CH_4 mixing ratios in these air samples. Flasks collected NE of BAO and not near feedlots (flasks 4, 6–8, and 10–12) fall on a line: $y = 0.114(x-1830)$ ($r^2 = 0.99$). This slope and the correlation slope calculated for the BAO NE wind sector data are indistinguishable (within the 1-σ uncertainties in the slopes). Four samples collected in the vicinity of four different cattle feedlots (flasks 2, 3, 5, and 9) exhibit a lower C_3H_8-to-CH_4 correlation slope (0.083 ppb/ppb, $r^2 = 0.93$). The r^2 for the C_3H_8-to-CH_4 correlation using all the flasks is 0.91.

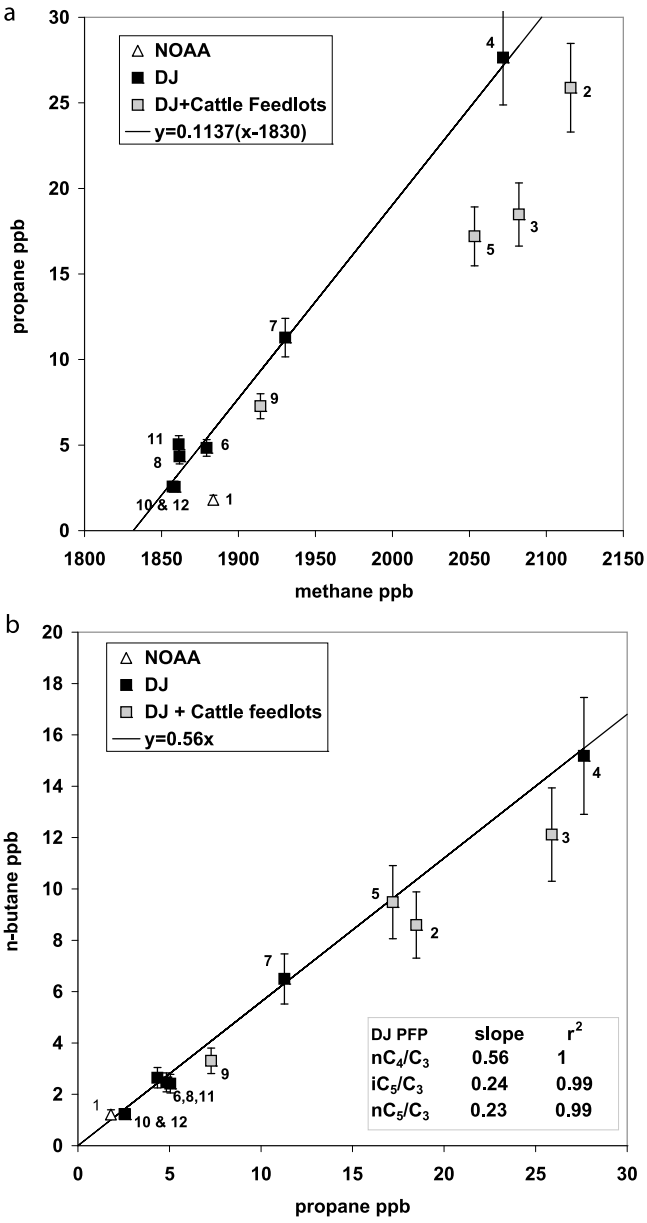

Figure 8. (a) Propane versus methane mixing ratios for air samples collected during Survey 6 on July 14, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 8a shows the correlation line for samples not impacted by local sources of methane (all flasks except 1–3, 5, and 9). The black line in Figure 8b shows the correlation line for samples not impacted by local sources of propane.

[53] The n-C_4H_{10} versus C_3H_8 correlation plot and its slope, along with the n-C_4H_{10}–to-C_3H_8 and C_5H_{12}–to-C_3H_8 correlation slopes for air samples not collected downwind of feedlots are shown in Figure 8b. The r^2 for the n-C_4H_{10}-to-C_3H_8 correlation using all the flasks is 0.98, which is slightly higher than the r^2 for the C_3H_8-to-CH_4 correlation using all flasks (0.91). The r^2 for the i-C_5H_{12}-to-n-C_4H_{10} and n-C_5H_{12}-to-n-C_4H_{10} correlations using all the flasks are 0.96 ppb/ppb and 0.99 ppb/ppb, respectively. These results suggest that cattle feedlots have no substantial impact on n-C_4H_{10} and the C_5H_{12} levels.

[54] The strong correlation observed between the various alkane mixing ratios for air samples not collected downwind of feedlots once again suggests that a common source contributes to most of the observed alkanes enhancements. It is possible that some of the C_3H_8 enhancements seen near the feedlots are due to leaks of propane fuel used for farm operations (R. Klusman, personal communication, 2010). Two flask samples were collected downwind of a cattle feedlot near Dacono during Mobile Lab survey 8, on 25 July 2008. The analysis of these samples revealed large CH_4 enhancements (1946 and 2335 ppb), but no enhancement in C_3H_8 (∼1ppb), n-C_4H_{10} (<300ppt), the C_5H_{12} (<130ppt) or C_6H_6 (<30ppt).

[55] For survey 6, the n-C_4H_{10}-to-C_3H_8 correlation slope (0.56 ppb/ppb) is 16% higher than the summer slope observed at BAO for the NE wind sector data, while the 14 July i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes (0.24 and 0.23 ppb/ppb, respectively) are 76% and 53% higher, respectively, than the summer NE BAO data. These slopes are higher than for flasks from survey 9. The difference in the C_5/C_3 slopes between the various Mobile Lab surveys data and the BAO NE summer data may reflect the spatial variability in the alkane source molar composition.

3.2.3. Benzene Source Signatures

[56] To look at the C_6H_6 correlations with other tracers, the 88 Mobile Lab flask samples have been divided into two subsets, none of which includes the three samples collected downwind of the natural gas and propane processing plant near Dacono, CO. In the summer, the lifetimes of C_6H_6 and C_3H_8 at 800 mbar and 40°N are close to 3 or 4 days and the lifetime of CO is about 10 days [*Finlayson-Pitts and Pitts*, 2000; *Spivakovsky et al.*, 2000].

[57] The first subset of 39 samples has C_3H_8 mixing ratios smaller than 3 ppb and it includes flasks collected mostly during surveys 2, 3 and 4. For this subset influenced mostly by urban and mobile emissions, C_6H_6 correlates well with CO (slope = 1.82 ppt/ppb, r^2 = 0.89) and C_2H_2 (slope = 0.37 ppt/ppt, r^2 = 0.75) but not with C_3H_8 (r^2 < 0.3). The C_6H_6-to-CO correlation slope for this subset is similar to the correlation slopes for the BAO S and W wind sector winter samples.

[58] The second subset of 46 samples corresponds to flasks with a C_3H_8 mixing ratio larger than 3ppb. These flasks were collected mostly during surveys 1, 6, 8 and 9. For this second subset influenced mostly by emissions from the DJB, C_6H_6 correlates well with C_3H_8 (slope = 17.9 ppt/ppb, r^2 = 0.95) but not with CO or C_2H_2 (r^2 < 0.3). The C_6H_6-to-C_3H_8 slope for these samples is almost twice as big as the slope calculated for the BAO NE wind sector data (10.1 ppt/ppb) (Table 3).

4. Discussion

4.1. Comparing the Alkane Enhancements in the BAO and Mobile Lab Data Sets

[59] In the previous section we showed two examples of enhanced alkanes in northeast Colorado using mobile sampling (surveys 6 and 9 on 14 and 31 July 2008, respectively). With lifetimes against OH removal on the order of 3.5, 1.7 and 1.0 days in the summer at 40°N [*Finlayson-Pitts and Pitts*, 2000; *Spivakovsky et al.*, 2000] respectively, C_3H_8,

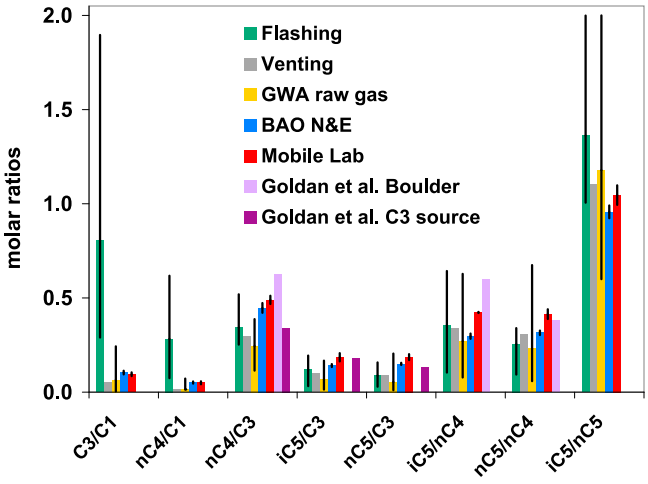

Figure 9. Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June–July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (gray) sources used by *Bar-Ilan et al.* [2008a] for the DJB WRAP Phase III emissions inventory. The error bars indicate the min and max values for the flashing emissions molar ratios. Also shown are the mean, min and max molar ratios derived from the composition analysis of gas samples collected in 2006 at 77 different gas wells in the Great Wattenberg Area (yellow) [*Colorado Oil and Gas Conservation Commission*, 2007]. *Goldan et al.* [1995] data are from a two week measurement campaign in the Foothills, west of Boulder, in February 1991 (light purple). Goldan et al. identified a "local" propane source (lower limit for correlation slope) with clear C_{4-5} alkane ratios to propane (dark purple, see also text). The error bars on the observed atmospheric molar ratios are the 2-sigma calculated for the ratios with linmix_err.pro (http://idlastro.gsfc.nasa.gov/ftp/pro/math/linmix_err.pro).

n-C_4H_{10} and the C_5H_{12} isomers do not accumulate over the continent. Instead their atmospheric mixing ratios and the slopes of correlations between different alkanes reflect mostly local or regional sources within a few days of atmospheric transport.

[60] The source responsible for the alkane enhancements observed at BAO and in multiple surveys during the Front Range Study appears to be located in the northeastern part of the Front Range region within the Denver-Julesburg Basin, so we call it the DJB source. The small differences in alkane correlation slopes for the BAO and Mobile Lab samples likely reflect differences in the emitted alkane molar ratios across this distributed source, as well as the mix of chemical ages for the air samples collected at a variety of locations and on different days.

[61] In Table 3 and Figure 4, we compare the alkane correlation slopes in the Mobile Lab flask data set with the correlation slopes in the BAO data set. To calculate the DJB source C_3H_8-to-CH_4 correlation slope from the Mobile Lab data set, we have removed air samples collected downwind of feedlots, the wastewater treatment plant, and the natural gas and propane processing plant (Figure 1). The Mobile Lab flasks C_3H_8-to-CH_4 correlation slope is 0.095 ± 0.007 ppb/ppb (R^2 = 0.76, 77 samples), similar to the slope calculated for the BAO NE wind sector data. Samples collected downwind of the natural gas processing plant exhibit variable chemical signatures, reflecting a complex mix of contributions from leaks of gas and combustion exhaust from flaring units and compressor engines.

[62] To calculate the DJB source n-C_4H_{10}-to-C_3H_8, i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes from the Mobile Lab data set, we have removed the three air samples collected downwind of the natural gas and propane processing plant (Figure 1). The C_4/C_3, i-C_5/C_3 and n-C_5/C_3 correlation slopes in the Mobile Lab data are 0.49, 0.19 and 0.19 ppb/ppb, respectively (r^2 > 0.8, 85 samples). The i-C_5/C_3 and n-C_5/C_3 correlation slopes are 40% and 30% higher, respectively, than the BAO NE sector summer slopes. If we remove the 11 data points from survey 6 samples collected in the middle of the DJB, the C_5H_{12}-to-C_3H_8 ratios are only 15% higher than calculated for the NE sector at BAO.

[63] High correlations among various alkanes were reported in this region by *Goldan et al.* [1995]. In that study, hourly air samples were analyzed with an in situ gas chromatograph deployed on a mesa at the western edge of Boulder for two weeks in February 1991. CH_4 was not measured during that study. The correlation coefficient (r^2) between C_3H_8, n-C_4H_{10}, and the C_5H_{12} isomers was around 0.86, with a clear minimum slope for the abundance ratios [see *Goldan et al.*, 1995, Figure 4]. The authors proposed that the C_4-C_6 alkanes shared one common source with propane (called the "C_3 source" in the next section and in Figure 9), with additional emissions contributing to some C_4-C_6 alkane enhancements.

4.2. Comparing the Front Range Observed Alkane Signatures With VOC Emissions Profiles for Oil And Gas Operations in the Denver-Julesburg Basin

[64] In this section we compare the alkane ratios calculated from the BAO NE wind sector and the Mobile Lab samples to emissions profiles from the DJB oil and gas exploration and production sector. Most of these profiles were provided by the WRAP Phase III inventory team, who developed total VOC and NOx emission inventories for oil and gas production and processing operation in the DJB for 2006 [*Bar-Ilan et al.*, 2008a]. Emissions and activity data were extrapolated by the WRAP Phase III inventory team to derive emission estimates for 2010 based on projected production numbers and on state and federal emissions control regulations put in place in early 2008 for oil and gas permitted activities in the DNFR NAA [*Bar-Ilan et al.*, 2008b]. The VOCs included in the inventories are: C_3H_8, i,n-C_4H_{10}, i,n-C_5H_{12} and higher alkanes, C_6H_6, toluene, ethyl-benzene, xylenes and 224-trimethylpentane. The WRAP Phase III inventories for 2006 and 2010 were only provided as total VOC and NOx emitted at the county level for all the counties in the Colorado part of the DJB. The emission estimates are based on various activity data (including the number of new wells (spuds), the total number of wells, estimates of oil, condensate and gas production, and equipment counts) and measured/reported or estimated VOC speciation profiles for the different source categories. Auxiliary material Figure S2 and *Bar-Ilan et al.* [2008a, 2008b] present more details on how the inventory emission estimates are derived.

[65] We focus primarily on flashing and venting sources here, since the WRAP Phase III inventory indicates that these two sources are responsible for 95% of the total VOC emissions from oil and gas exploration and production operations in Weld County and in the NAA [*Bar-Ilan et al.*, 2008a, 2008b] (see auxiliary material Figure S2). In 2006, all the oil produced in the DJB was from condensate wells. Condensate tanks at well pads or processing plants store a mostly liquid mix of hydrocarbons and aromatics separated from the lighter gases in the raw natural gas. Flash losses or emissions happen for example when the liquid condensate is exposed to decreasing atmospheric pressure: gases dissolved in the liquid are released and some of the heavier compounds may be entrained with these gases. Flashing emissions from condensate storage tanks are the largest source of VOCs from oil and gas operations in the DJB. In the DNFR NAA, operators of large condensate tanks have to control and report emission estimates to the Colorado Department of Public Health and the Environment (CDPHE). In 2006 and 2010 flashing emissions represented 69% and 65% respectively of the total VOC source from oil and gas exploration, production and processing operations, for the nine counties in the NAA (see auxiliary material Figure S2 and *Bar-Ilan et al.* [2008a] for more details on how the estimates are derived).

[66] Venting emissions are related to loss of raw natural gas when a new oil or gas well is drilled or when an existing well is vented (blowdown), repaired or restimulated (recompletion). Equipment at active well sites (e.g., wellhead, glycol dehydrators and pumps) or in the midstream network of compressors and pipelines gathering the raw natural gas can also leak significant amounts of natural gas. In the WRAP Phase III inventory, venting emissions represented 27% and 21% respectively of the total VOC estimated source from the NAA oil and gas operations in 2006 and 2010 (see *Bar-Ilan et al.* [2008a, 2008b] and auxiliary material Figure S2).

[67] The molar compositions of venting and flashing emissions are quite different (see auxiliary material Figure S4). Emissions from flash losses are enriched in C_{2+} alkanes compared to the raw natural gas emissions. To convert the total VOC bottom-up source into speciated emission ratio estimates, we use molar ratio profiles for both flashing and venting emissions reported in three data sets: (1) *Bar-Ilan et al.* [2008a]: mean venting profile used for the 2006 DJB inventory, also called the "Venting-WRAP" profile; (2) *Colorado Oil and Gas Conservation Commission* (*COGCC*) [2007]: composition of 77 samples of raw natural gas collected at different wells in the Greater Wattenberg Area in December 2006, also called "Venting-GWA" profiles. Note that C_6H_6 was not reported in this data set; and (3) Colorado Department of Public Health and the Environment (C. LaPlante, CDPHE, personal communication, 2011): flashing emissions profiles based on condensate composition data from 16 different storage tanks in the DJB and EPA TANK2.0 (flashing emissions model) runs.

[68] Figure 9 shows a comparison of the alkane molar ratios for the raw natural gas and flash emissions data sets with the correlation slopes derived for the Mobile Lab 2008 samples and for air samples collected at BAO in the summer months only (between August 2007 and April 2010) for the NE wind sector (see auxiliary material Table S4 to get the plotted values). The alkane correlation slopes observed at BAO and across the Northern Front Range with the Mobile Lab are all within the range of ratios reported for flashing and/or venting emissions. The C_{3-5} alkane ratios for both flashing and venting emissions are too similar for their atmospheric ratios to be useful in distinguishing between the two source processes. The ambient C_3H_8-to-CH_4 and n-C_4H_{10}-to-CH_4 molar ratios are lower than what could be expected from condensate tank flashing emissions alone, indicating that most of the CH_4 observed came from the venting of raw natural gas. In the next section, we will describe how we derive bottom-up emission estimates for CH_4 and C_3H_8 as well as three top-down emissions scenarios consistent with the observed atmospheric slopes.

[69] Figure 9 also shows the correlation slopes calculated by *Goldan et al.* [1995] for the 1991 Boulder study. These slopes compare very well with the BAO and Mobile Lab results and the oil and gas venting and flashing emissions ratios. *Goldan et al.* [1995] compared the measured C_4/C_3 and C_5/C_3 ratios for the Boulder C_3 source (see definition in section 4.1) with the ratios reported in the locally distributed pipeline-quality natural gas for February 1991, and concluded that the common C_3H_8 and higher alkane source was not linked with the local distribution system of processed natural gas. However, the composition of the raw natural gas at the extraction well is quite different from the purified pipeline-quality natural gas distributed to end-users. Processed pipeline-quality natural gas delivered throughout the USA is almost pure CH_4 [*Gas Research Institute*, 1992]. Since *Goldan et al.* [1995] did not measure CH_4 in their 1991 study, they could not determine if the atmospheric C_{3+}/C_1 alkane ratios were higher than expected in processed natural gas.

4.3. Estimation of the Alkane Source in Weld County

4.3.1. Bottom-Up Speciated Emission Estimates

[70] In this section, we derive bottom-up and top-down estimates of alkane emissions from the DJB source for Weld County. We have averaged the 2006 and 2010 WRAP Phase III total VOC emissions data [*Bar-Ilan et al.*, 2008a, 2008b] to get bottom-up estimates for the year 2008, resulting in 41.3 Gg/yr for flashing emissions and 16.8 Gg/yr for venting emissions. There are no uncertainty estimates provided in the WRAP Phase III inventory. 2006 total VOC flashing emission estimates in Weld County are based on reported emissions for controlled large condensate tanks (34.8 Gg/yr) and calculated emissions for uncontrolled small condensate tanks (5.4 Gg/yr) (see *Bar-Ilan et al.* [2008a] for more details). Uncertainties attached to these estimates may be due to inaccurate emissions factors (number of pounds of VOC flashed per tons of condensate produced) and/or inaccurate estimate of the effectiveness of emission control systems.

[71] The WRAP Phase III total VOC emission from venting sources for Weld County was calculated by averaging industry estimates of the volume of natural gas vented or leaked to the atmosphere by various processes shown in auxiliary material Figure S2 (well blowdown, well completion, pneumatic devices…). A basin-wide average of gas composition analyses provided by oil and gas producers was then used to compute a bottom-up estimate of the total mass of VOC vented to the atmosphere by oil and gas exploration, production and processing operations. Uncertainties attached to the venting source can be related to

Table 4. Bottom-Up (Inventory-Derived) Emission Estimates and Top-Down Emissions Scenarios for CH_4 and C_3H_8 in Weld County

	Bottom-Up Estimates				Top-Down Scenarios: Venting[a] (Gg/yr)			Top-Down Scenarios: TOTAL Bottom-Up Flashing + Top-Down Venting[a] (Gg/yr)			Top-Down Scenarios: Percent Of Production Vented[a,b]		
	Flashing[c] (Gg/yr)	Venting[d] (Gg/yr)	Flashing + Venting (Gg/yr)	Percent of Production Vented[e]	1	2	3	1	2	3	1	2	3
Methane	**11.2**	53.1	64.3	**1.68%**	118.4	92.5	157	**129.6**	103.7	168.2	**4.0%**	3.1%	5.3%
Min[f]	**4**	42	46		86.5	67.6	114.7	90.5	**71.6**	118.7	2.9%	**2.3%**	3.8%
Max[f]	**23**	63	86		172.6	134.9	228.9	195.6	157.9	**251.9**	5.8%	4.5%	**7.7%**
Propane	**18.3**	7.8	26.1		17.4	10.2	28	**35.7**	28.5	46.3			
Min[f]	**14**	1	15		12.7	7.5	20.5	26.7	**21.5**	34.5			
Max[f]	**24**	28	52		25.3	14.9	40.8	49.3	38.9	**64.8**			

[a]The CH_4-to-C_3H_8 molar ratio for vented natural gas is 18.75 (WRAP report estimate) for scenario 1, 15.43 for scenario 2 (median of molar ratios in GWA data set) and 24.83 for scenario 3 (mean of molar ratios in GWA data set).

[b]Using the assumptions of a CH_4 molar ratio of 77% for the vented natural gas and a molar volume for the gas of 23.6 L/mol (Pressure = 14.73 pounds per square inch and Temperature = 60°F) as used by the *EIA* [2004].

[c]The bottom-up flashing emissions for methane and propane were calculated using the 2008 estimate of total VOC flash emissions derived by averaging the WRAP estimate for 2006 and the projection for 2010 (Cf. section 4.3).

[d]The bottom-up venting emissions for methane and propane were calculated using the WRAP Phase III inventory estimate for the total volume of natural gas vented and the GWA 77 natural gas composition profiles.

[e]Using the WRAP Phase III inventory data set and assumptions, including a CH_4 mean molar ratio of 77.44% for the vented natural gas and a molar volume for the gas of 22.4 L/mol.

[f]The minimum and maximum values reported here come from the ensemble of 16 condensate tank emissions speciation profiles provided by CDPHE.

uncertainties in leak rates or intensity of out-gassing events, as well to the variability in the composition of raw natural gas, none of which were quantitatively taken into account in the WRAP Phase III inventory.

[72] Next we describe the calculations, summarized in auxiliary material Figure S5, to derive bottom-up estimates of venting and flashing emissions for the various trace gases we measured using information from the WRAP Phase III inventory and the COGCC GWA raw natural gas composition data set (Table 4 and auxiliary material Figure S6). From the total annual vented VOC source and the average vented emission profile provided by *Bar-Ilan et al.* [2008a] (auxiliary material Table S2), we derived an estimate of the volume of natural gas that we assumed is vented to the atmosphere by the oil and gas production and processing operations in Weld County. Following *Bar-Ilan et al.* [2008a] inventory data and assumptions, we used the weight fraction of total VOC in the vented gas (18.74%), the molar mass of the vented gas (21.5g/mol) and standard pressure and temperature with the ideal gas law to assume that 1 mol of raw natural gas occupies a volume 22.4 L (as was done in the WRAP Phase III inventory). The total volume of vented gas we calculate for Weld County in 2008 is 3.36 billion cubic feet (Bcf), or the equivalent of 1.68% of the total natural gas produced in the county in 2008 (202.1 Bcf). We then use the estimate of the volume of vented gas and the molar composition profiles for the 77 raw natural gas samples reported in the COGCC GWA study to compute average, minimum, and maximum emissions for CH_4, each of the C_{3-5} alkanes we measured, and C_6H_6. Using this procedure, 2008 Weld County average venting CH_4 and C_3H_8 bottom-up source estimates are 53.1 Gg/yr and 7.8 Gg/yr, respectively (Table 4).

[73] For flashing emissions, we distributed the WRAP 2008 total annual VOC source estimate (41.3 Gg/yr) using the modeled flash loss composition profiles for 16 different condensate tanks provided by the CDPHE. Average CH_4 and C_3H_8 emissions as well as the minimum and maximum estimates are reported in Table 4. The 2008 average flashing CH_4 and C_3H_8 bottom-up emission estimates are 11.2 Gg/yr and 18.3 Gg/yr, respectively (Table 4). The total flashing + venting CH_4 and C_3H_8 bottom-up estimates range from 46 to 86 Gg/yr and from 15 to 52 Gg/yr, respectively.

4.3.2. Top-Down Emissions Scenarios

[74] Finally, we use our atmospheric measurements to bring new independent constraints for the estimation of venting and flashing emissions in Weld County in 2008. The exercise consists in calculating three top-down venting emission scenarios for CH_4 and C_3H_8 (x_m, x_p: mass of methane and propane vented respectively) consistent with a mean observed CH_4-to-C_3H_8 atmospheric molar ratio of 10 ppb/ppb (Table 4) in the DJB. We assume, as done earlier in the bottom-up calculations, that the observed C_3H_8-to-CH_4 ratio in the DJB results from a combination of flashing and venting emissions. The bottom-up information used here is (1) the set of speciated flashing emissions derived earlier for the 16 condensate tanks provided by CDPHE for CH_4 and C_3H_8 $(y_m, y_p)_{\text{tank}=1,16}$, and (2) three scenarios for the basin-average raw (vented) natural gas CH_4-to-C_3H_8 molar ratio, denoted $\boldsymbol{v}_{m/p}$. The three values used for basin-average vented gas CH_4-to-C_3H_8 molar ratio are: 18.75, which is the WRAP Phase III inventory assumption (scenario 1); 15.43, which is the median of the molar ratios for the COGCC GWA 77 gas samples (scenario 2); and 24.83, which is the mean of the molar ratios for the COGCC GWA 77 gas samples (scenario 3). For each vented gas profile scenario, we use the set of 16 flash emission estimates to calculate an ensemble of venting emission estimates for CH_4 (x_m) and C_3H_8 (x_p) following the two equations below.

[75] The first equation formalizes the assumption for CH_4-to-C_3H_8 molar ratio of the vented raw natural gas, with M_m (16g/mol) and M_p (44g/mol) being the molar masses of CH_4 and C_3H_8 respectively.:

$$v_{m/p} = \frac{M_p}{M_m} \times \frac{x_m}{x_p} \tag{1}$$

[76] In the second equation, the mean observed atmospheric CH_4-to-C_3H_8 molar ratio ($a_{m/p}$ = 10 ppb/ppb)

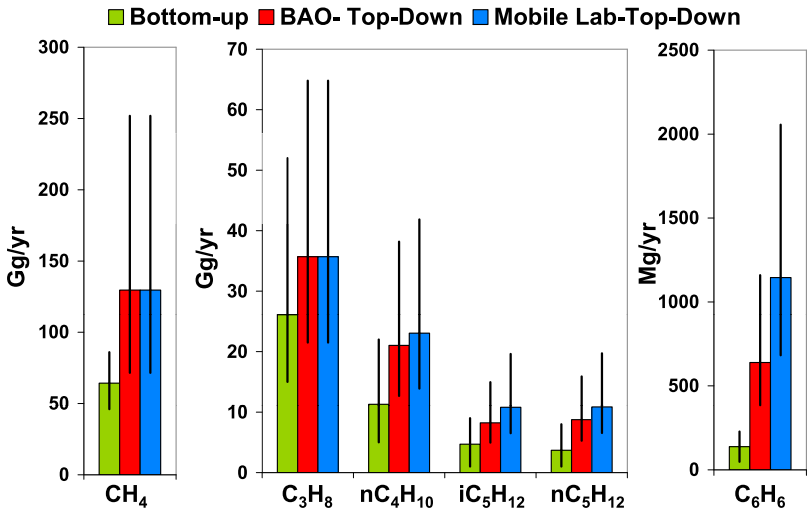

Figure 10. Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios described in Table 4.

constrains the overall ratio of methane versus propane emitted by both flashing and venting sources. Therefore, for each set of 16 bottom-up flashed emission estimates (y_m, y_p), we have:

$$\frac{M_p(x_m + y_m)}{M_m(x_p + y_p)} = a_{m/p} \tag{2}$$

[77] The analytical solutions to this set of equations are given by:

$$\begin{aligned} x_p &= \frac{1}{(v_{m/p} - a_{m/p})} \times \left(a_{m/p} \times y_p - \frac{M_p}{M_m} y_m\right) \\ x_m &= v_{m/p} \times \frac{M_m}{M_p} \times x_p \end{aligned} \tag{3}$$

[78] The average, minimum and maximum venting emission estimates, x_m and x_p, are reported for the three vented gas profile scenarios in Table 4 and Figure 10.

[79] The first goal of this top-down estimation exercise is to highlight the many assumptions required to build the bottom-up and top-down emission estimates. The choices made for the WRAP Phase III inventory or our top-down calculations are all reasonable, and the uncertainty attached to the values chosen (if available) should be propagated to calculate total uncertainty estimates for the final emission products. When the error propagation is done conservatively, the emission uncertainty is close to a factor of 2 for both CH_4 and C_3H_8. This number is much higher than the 30% uncertainty reported by the EPA for the 2009 national CH_4 source estimate from natural gas systems [*EPA*, 2011].

[80] The scenario 1 mean top-down vented CH_4 source (118.4 Gg/yr) is twice as large as the bottom-up estimate of 53.1 Gg/yr (Table 4). If we assume that 77% (by volume) of the raw gas is CH_4, an average estimate of 118.4 Gg/yr of CH_4 vented would mean that the equivalent of 4% of the 2008 natural gas gross production in Weld County was vented. It is important to note that the top-down scenarios cover a large range (67–229 Gg/yr), corresponding to between 2.3% and 7.7% of the annual production being lost to the atmosphere through venting (Table 4). The lowest estimate is, however, larger than what we derived from the WRAP Phase III bottom-up inventory (1.68%). If instead of using the *EIA* [2004] convention for the molar volume of gas (23.6 L/mol), we used the standard molar volume used by WRAP (22.4 L/mol), our top-down calculations of the volume of gas vented would be 5% lower than reported in Table 4.

[81] Emissions for the other alkanes measured are all derived from the C3H8 total sources scaled with the atmospheric molar ratios observed in the BAO NE summer samples and the Mobile Lab samples. Figure 10 shows a comparison of the bottom-up estimates and the top-down emission scenarios (mean of scenario 1 and overall minimum and maximum of the three scenarios).

[82] The main result of this exercise is that for each of the three top-down total emissions scenarios, the mean estimates for CH_4, n-C_4H_{10} and the C_5H_{12} isomers are at least 60% higher than the bottom-up mean estimates. The minimum top-down emissions scenarios are lower than (in the case of C_3H_8) or higher than (for CH_4, nC_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) the bottom-up mean estimates.

[83] To put the top-down CH_4 source estimate from oil and gas exploration, production and processing operations in perspective, we compare it with an estimate of the passive "geological" CH_4 flux over the entire DJB. *Klusman and Jakel* [1998] reported an average flux of 0.57 mg CH_4/m^2/day in the DJB due to natural microseepage of light alkanes. Multiplied by a rough upper boundary estimate of the DJB surface area (Figure 1), the estimated annual natural flux is 0.66 Gg CH_4 /yr, or less than 1% of the top-down venting source estimated for active exploration and production of natural gas in Weld County.

4.4. Benzene Sources in the Northern Front Range

[84] On-road vehicles are estimated to be the largest source of C_6H_6 in the U.S. (EPA, 2008 report on the environment,

2009, www.epa.gov/roe). Emissions from on-road and off-road vehicles and from large point sources (including chemical plants and refineries) have been regulated by the EPA for over thirty years [*Fortin et al.*, 2005; *Harley et al.*, 2006]. When motor vehicle combustion dominates emissions, such as in the BAO S and W wind sectors, C_6H_6 correlates well with CO and C_2H_2.

[85] Crude oil and natural gas production and processing emitted an estimated 8333 tonnes of benzene nationally in 2005, which represented 2% of the national total C_6H_6 source (EPA, 2008 report on the environment, 2009, www.epa.gov/roe). C_6H_6 and C_3H_8 have similar photochemical lifetimes (~3–4 days in the summer), so the observed atmospheric ratios we report in Table 3 should be close to their emission ratio if they are emitted by a common source. The strong correlation between C_6H_6 and C_3H_8 (Figure 4 and Table 3) for the BAO NE wind sector and in the DJB Mobile Lab air samples suggests that oil and gas operations could also be a non-negligible source of C_6H_6 in the Northern Colorado Front Range.

[86] The C_6H_6-to-C_3H_8 molar ratios in the flash losses from 16 condensate tanks simulated with the EPA TANK model are between 0.4 to 5.6 ppt/ppb. The C_6H_6-to-C_3H_8 molar ratio reported for vented emissions in the WRAP Phase III inventory is 5.3 ppt/ppb, based on regionally averaged raw gas speciation profiles provided by local companies [*Bar-Ilan et al.*, 2008a] (only an average profile was provided, other data is proprietary). These emission ratios are at least a factor of two lower than the atmospheric ratios measured in the Front Range air samples influenced by the DJB source (Table 3).

[87] If we use the mean C_3H_8 emission estimate for scenario 1 described in section 4.3 (35.7 Gg/yr), together with the C_6H_6-to-C_3H_8 correlation slope for the summer BAO NE wind sector data and that from the Mobile Lab samples (10.1 ppt/ppb and 17.9 ppt/ppb respectively), we derive a C_6H_6 emission estimate for the DJB source in Weld County in 2008 of 639 tonnes/yr (min/max range: 478/883 tonnes/yr) and 1145 tonnes/yr (min/max range: 847/1564 tonnes/yr), respectively. As expected, these numbers are much higher than what we derived for the bottom-up flashing and venting emissions (total of 139 tonnes/yr, min/max range of 49–229 tonnes/yr). For comparison, C_6H_6 emissions from facilities in Colorado reporting to the U.S. EPA for the Toxics Release Inventory amounted to a total of 3.9 tonnes in 2008 (EPA, Toxics Release Inventory program, 2009, data available at http://www.epa.gov/triexplorer/chemical.htm) and on–road emissions in Weld County were estimated at 95.4 tonnes/yr in 2008 (C. LaPlante, CDPHE, personal communication, 2011). Based on our analysis, oil and gas operations in the DJB could be the largest source of C_6H_6 in Weld County.

[88] More measurements are needed to further evaluate the various potential sources associated with oil and gas operations (for example, glycol dehydrators and condensate tank flash emissions). The past two iterations of the C_6H_6 emissions inventory developed by the State of Colorado for the National Emissions Inventory and compiled by the EPA do not show much consistency from one year to another. The 2008 and 2005 NEI reported very different C_6H_6 emission estimates for condensate tanks in Weld County (21.5 Mg/yr versus 1120 Mg/yr, respectively; see also auxiliary material Table S3). Estimates in the 2008 NEI are much closer to estimates provided by CDPHE (C. LaPlante, personal communication, 2011) for 2008 (21.3 Mg/yr), suggesting the 2005 NEI estimate may be flawed, even though it is in the range of our top-down estimation. We conclude that the current level of understanding of emissions of C_6H_6 from oil and gas operations cannot explain the top-down range of estimates we derive in our study, suggesting that, once again, more field measurements are needed to understand and quantify oil and gas operation sources.

5. Conclusion

[89] This study provides a regional overview of the processes impacting ambient alkane and benzene levels in northeastern Colorado in the late 2000s. We report atmospheric observations collected by two sampling platforms: a 300-m tall tower located in the SW corner of Weld County (samples from 2007 to 2010), and road surveys by a Mobile Lab equipped with a continuous methane analyzer and discrete canister sampling (June–July 2008). The analysis of the tower data filtered by wind sector reveals a strong alkane and benzene signature in air masses coming from northeastern Colorado, where the main activity producing these compounds is related to oil and gas operations over the Denver–Julesburg Fossil Fuel Basin. Using the Mobile Lab platform, we sampled air directly downwind of different methane sources (oil and gas wells, a landfill, feedlots, and a wastewater treatment plant) and collected targeted air samples in and out of plumes. The tall tower and Mobile Lab data both revealed a common source for air masses with enhanced alkanes. In the data from both platforms, the alkane mixing ratios were strongly correlated, with slight variations in the correlation slopes depending on the location and day of sampling. The alkanes did not correlate with combustion tracers such as carbon monoxide and acetylene. We hypothesize that the observed alkanes were emitted by the same source located over the Denver-Julesburg Basin, "the DJB source."

[90] The second part of the study brings in information on VOC emissions from oil and gas activities in the DJB from the detailed bottom-up WRAP Phase III inventory [*Bar Ilan et al.*, 2008a, 2008b]. We have used the total VOC emission inventory and associated emissions data for DJB condensate and gas production and processing operations to calculate annual emission estimates for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The main findings are summarized below:

1. The emissions profiles for flashing and venting losses are in good agreement with the atmospheric alkane enhancement ratios observed during this study and by *Goldan et al.* [1995] in Boulder in 1991. This is consistent with the hypothesis that the observed alkane atmospheric signature is due to oil and gas operations in the DJB.

2. The three top-down emission scenarios for oil and gas operations in Weld County in 2008 give a rather large range of potential emissions for CH_4 (71.6–251.9 Gg/yr) and the higher alkanes. Except for propane, the lowest top-down alkanes emission estimates are always larger than the inventory-based mean estimate we derived based on the WRAP Phase III inventory data and the COGCC GWA raw gas composition data set.

3. There are notable inconsistencies between our results and state and national regulatory inventories. In 2008 gas wells in Weld County represented 15% of the state's production. Based on our top-down analysis, Weld County methane emissions from oil and gas production and processing represent at least 30% of the state total methane source from natural gas systems derived by *Strait et al.* [2007] using the EPA State Inventory Tool. The methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two. Oil and gas operations are the largest source of alkanes in Weld County. They were included as a source of "total VOC" in the 2008 EPA NEI for Weld County but not in the 2005 NEI.

4. There are at least two main sources of C_6H_6 in the region: one related to combustion processes, which also emit CO and C_2H_2 (engines and mobile vehicles), and one related to the DJB alkane source. The C_6H_6 source we derived based on flashing and venting VOC emissions in the WRAP inventory (143 Mg/yr) most likely underestimates the actual total source of C_6H_6 from oil and gas operations. Our top-down source estimates for C_6H_6 from oil and gas operations in Weld County cover a large range: 385–2056 Mg/yr. Again, the lowest figure is much higher than reported in the 2008 CDPHE inventory for Weld County oil and gas total point sources (61.8 Mg/yr).

5. Samples collected at the BAO tall tower or while driving around the Front Range reflect the emissions from a complex mix of sources distributed over a large area. Using a multispecies analysis including both climate and air quality relevant gases, we can start unraveling the contributions of different source types. Daily multispecies measurements from the NOAA collaborative network of tall towers in the U.S. provide a unique opportunity to understand source chemical signatures in different airsheds and how these emissions may change over time.

6. More targeted multispecies well-calibrated atmospheric measurements are needed to evaluate current and future bottom-up inventory emissions calculations for the fossil fuel energy sector and to reduce uncertainties on absolute flux estimates for climate and air quality relevant trace gases.

[91] **Acknowledgments.** The authors thank John Grant (ENVIRON) and Kathleen Sgamma (Western Energy Alliance) for their expertise and support in interpreting the WRAP Phase III inventory public data. Special thanks are extended to the NOAA personnel and collaborators responsible for flask preparation, sample collection and sample analysis, data quality control and database management.

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ENERGY

Methane leaks erode green credentials of natural gas

Losses of up to 9% show need for broader data on US gas industry's environmental impact.

BY JEFF TOLLEFSON

Scientists are once again reporting alarmingly high methane emissions from an oil and gas field, underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system.

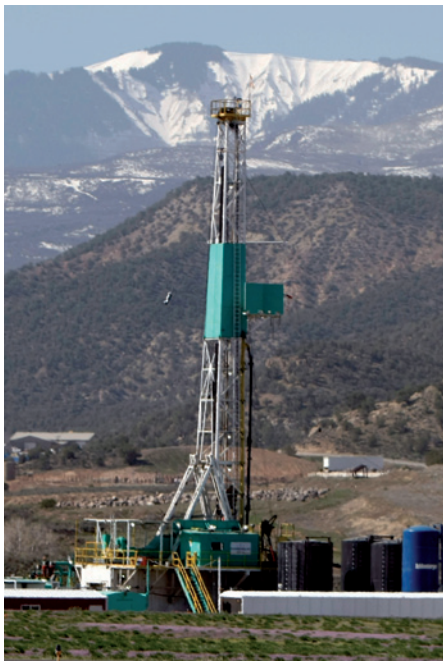
The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study[1] suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.

Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.

"We were expecting to see high methane levels, but I don't think anybody really comprehended the true magnitude of what we would see," says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA's Earth System Research Laboratory in Boulder.

Whether the high leakage rates claimed in Colorado and Utah are typical across the US natural-gas industry remains unclear. The NOAA data represent a "small snapshot" of a much larger picture that the broader scientific community is now assembling, says Steven Hamburg, chief scientist at the Environmental Defense Fund (EDF) in Boston, Massachusetts.

The NOAA researchers collected their data in February as part of a broader analysis of air pollution in the Uinta Basin, using ground-based equipment and an aircraft to make detailed measurements of various pollutants, including methane concentrations. The researchers used atmospheric modelling to calculate the level of methane emissions required to reach those concentrations, and then compared that with industry data on gas production to obtain the percentage escaping into the atmosphere through venting and leaks.



Natural-gas wells such as this one in Colorado are increasingly important to the US energy supply.

J. DAVID ZALUBOWSKI/AP

The results build on those of the earlier Colorado study[1] in the Denver–Julesburg Basin, led by NOAA scientist Gabrielle Pétron (see *Nature* **482,** 139–140; 2012). That study relied on pollution measurements taken in 2008 on the ground and from a nearby tower, and estimated a leakage rate that was about twice as high as official figures suggested. But the team's methodology for calculating leakage — based on chemical analysis of the pollutants — remains in dispute. Michael Levi, an energy analyst at the Council on Foreign Relations in New York, published a peer-reviewed comment[2] questioning the findings and presenting an alternative interpretation of the data that would align overall leakage rates with previous estimates.

Pétron and her colleagues have a defence of the Colorado study in press[3], and at the AGU meeting she discussed a new study of the Denver–Julesburg Basin conducted with scientists at Picarro, a gas-analyser manufacturer based in Santa Clara, California. That study relies on carbon isotopes to differentiate between industrial emissions and methane from cows and feedlots, and the preliminary results line up with their earlier findings.

A great deal rides on getting the number right. A study[4] published in April by scientists at the EDF and Princeton University in New Jersey suggests that shifting to natural gas from coal-fired generators has immediate climatic benefits as long as the cumulative leakage rate from natural-gas production is below 3.2%; the benefits accumulate over time and are even larger if the gas plants replace older coal plants. By comparison, the authors note that the latest estimates from the US Environmental Protection Agency (EPA) suggest that 2.4% of total natural-gas production was lost to leakage in 2009.

To see if that number holds up, the NOAA scientists are also taking part in a comprehensive assessment of US natural-gas emissions, conducted by the University of Texas at Austin and the EDF, with various industry partners. The initiative will analyse emissions from the production, gathering, processing, long-distance transmission and local distribution of natural gas, and will gather data on the use of natural gas in the transportation sector. In addition to scouring through industry data, the scientists are collecting field measurements at facilities across the country. The researchers expect to submit the first of these studies for publication by February, and say that the others will be complete within a year.

In April, the EPA issued standards intended to reduce air pollution from hydraulic-fracturing operations — now standard within the oil and gas industry — and advocates say that more can be done, at the state and national levels, to reduce methane emissions. "There are clearly opportunities to reduce leakage," says Hamburg. ■

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Quantifying sources of methane using light alkanes in the Los Angeles basin, California

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Abstract

Methane (CH_4), carbon dioxide (CO_2), carbon monoxide (CO), and C_2–C_5 alkanes were measured throughout the Los Angeles (L.A.) basin in May and June 2010. We use these data to show that the emission ratios of CH_4/CO and CH_4/CO_2 in the L.A. basin are larger than expected from population-apportioned bottom-up state inventories, consistent with previously published work. We use experimentally determined CH_4/CO and CH_4/CO_2 emission ratios in combination with annual State of California CO and CO_2 inventories to derive a yearly emission rate of CH_4 to the L.A. basin. We further use the airborne measurements to directly derive CH_4 emission rates from dairy operations in Chino, and from the two largest landfills in the L.A. basin, and show these sources are accurately represented in the California Air Resources Board greenhouse gas inventory for CH_4. We then use measurements of C_2–C_5 alkanes to quantify the relative contribution of other CH_4 sources in the L.A. basin, with results differing from those of previous studies. The atmospheric data are consistent with the majority of CH_4 emissions in the region coming from fugitive losses from natural gas in pipelines and urban distribution systems and/or geologic seeps, as well as landfills and dairies. The local oil and gas industry also provides a significant source of CH_4 in the area. The addition of CH_4 emissions from natural gas pipelines and urban distribution systems and/or geologic seeps and from the local oil and gas industry is sufficient to account for the differences between the top-down and bottom-up CH_4 inventories identified in previously published work.

1. Introduction

In California, methane (CH_4) emissions are regulated by Assembly Bill 32, enacted into law as the California Global Warming Solutions Act of 2006, requiring the state's greenhouse gas (GHG) emissions in the year 2020 not to exceed 1990 emission levels. To this end, the California Air Resources Board (CARB) was tasked with compiling and verifying an inventory of GHG emissions for the state. Two published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010] have concluded that atmospheric emissions of CH_4 in the Los Angeles (L.A.) area were greater than expected from a per capita apportionment of the statewide 2006 CARB GHG inventory and from a bottom-up accounting of CH_4 sources, respectively.

Several recent works have estimated CH_4 emissions to the South Coast Air Basin (SoCAB; Fig. 1a), which are summarized in Table 1. *Wunch et al.* [2009] used a Fourier transform infrared spectrometer at the Jet Propulsion Laboratory (JPL) in Pasadena, California to measure vertically-integrated total column enhancement ratios of CH_4 relative to CO and to CO_2. The observed column enhancement ratios, multiplied by CARB inventory values of CO for 2008 and an average of 2006 CARB GHG inventory and 2005 Emission Database for Global Atmospheric Research (EDGAR) for CO_2, were used to derive a lower limit to CH_4 emissions of 400 ± 100 Gg CH_4/yr (based on CO) or 600 ± 100 Gg CH_4/yr (based on CO_2) for the SoCAB. One reason for the discrepancy in their top-down analysis was that their observed CO/CO_2 enhancement ratio of 11 ± 2 ppb CO/ppm CO_2 was greater than the 8.6 ppb CO/ppm CO_2 calculated from the inventories. *Wunch et al.* [2009] contrasted these top-down assessments to a bottom-up estimate of 260 Gg CH_4/yr using the statewide 2006 CARB GHG inventory

apportioned by population after removal of agricultural and forestry emissions, and concluded that 140 – 340 Gg CH_4/yr were not accounted for in the CARB CH_4 inventory for the SoCAB.

Hsu et al. [2010] took a similar top-down approach and used observed atmospheric enhancement ratios of CH_4 to CO from *in situ* whole air samples taken at Mt. Wilson (34.22° N, 118.06° W, 1770 m above sea level), scaled by the projected CARB CO inventory for 2008, to derive CH_4 emissions of 200 ± 10 Gg CH_4/yr for just the Los Angeles (L.A.) County (Figure 1b) portion of the SoCAB (L.A. County ∩ SoCAB). They used methods prescribed by the Intergovernmental Panel for Climate Change (IPCC) to create the CARB GHG inventory and reached a bottom-up estimate of 140 Gg CH_4/yr, or 60 Gg less than their top-down calculation for the L.A. County portion of the SoCAB. *Hsu et al.* [2010] used higher spatial resolution emissions data from CARB to construct their bottom-up inventory, and therefore did not have to rely on population apportionment methods used by *Wunch et al.* [2009].

The difference between the top-down CH_4 emissions reported by *Wunch et al.* [2009] and by *Hsu et al.* [2010] (400 Gg and 200 Gg, respectively, both based on the CARB CO inventory) are in part due to the different geographic areas for which they calculate CH_4 emissions, and in part due to differences in observed CH_4/CO enhancements between these two studies: 0.66 ± 0.12 mol/mol for *Wunch et al.* [2009] [*Wennberg et al.*, 2012] and 0.52 ± 0.02 mol/mol for *Hsu et al*. [2010]. Both works suggested that fugitive losses of natural gas (NG) could be the source of the CH_4 missing from the bottom-up inventories.

More recently, *Townsend-Small et al.* [2012] analyzed stable CH_4 isotope ratios in atmospheric samples taken at Mt. Wilson and elsewhere in the western L.A. basin and showed they were consistent with isotope ratios in natural gas sources.

Wennberg et al. [2012] used the different atmospheric ethane/CH_4 enhancement ratios observed from research aircraft during the Arctic Research of the Composition of the Troposphere from Aircraft and Satellites (ARCTAS) field project in 2008 and the California Research at the Nexus of Air Quality and Climate Change (CalNex) field project [*Ryerson et al.*, in review] in 2010 to estimate an upper limit of 390 Gg CH_4/yr from natural gas leakage in the SoCAB. Further, their top-down analysis resulted in a calculated total emission of 440 Gg CH_4/yr in the SoCAB. *Wennberg et al.* [2012] also recalculated the data used by *Hsu et al.* [2010] to derive CH_4 emissions for the entire SoCAB, and calculated a SoCAB CH_4 emission from 2008 using data from ARCTAS. The results are summarized in Table 1.

Here we use ambient measurements in the SoCAB taken in May and June 2010 aboard the National Oceanic and Atmospheric Administration (NOAA) P-3 research aircraft during the CalNex field study to derive CH_4 emissions from the SoCAB using methods different from *Wennberg et al.* [2012]. We further examine CH_4 emissions from landfills and dairy farms in the SoCAB identified in the bottom-up CH_4 inventories reported by *Hsu et al.* [2010] and *Wennberg et al.* [2012]. We then expand on these previous studies by examining light alkane emissions from Los Angeles area data sets. In addition to CH_4 and ethane, we examine propane, *n*- and *i*-butane, and *n*- and *i*-pentane measurements to derive emissions of each of these light alkanes in the SoCAB, and use them in a system of linear equations to further quantify the source apportionment of CH_4 in the L.A. basin.

2. Measurements

We use trace gas measurements from a subset of platforms and sites from the CalNex field study. The NOAA P-3 research aircraft flew all or parts of 16 daytime flights in and around the L.A. basin. Two independent measurements of CH_4 and CO_2 were made aboard the aircraft by wavelength-scanned cavity ring-down spectroscopy (WS-CRDS; Picarro 1301-m) [*Peischl et al.*, 2012], and by quantum cascade laser direct absorption spectroscopy (QCLS) [*Kort et al.*, 2011]. Imprecision of the 1-Hz Picarro CH_4 measurement is ± 1.4 ppbv (all uncertainties herein are 1-σ) and inaccuracy is estimated at ± 1.2 ppbv. Imprecision of the 1-Hz QCLS CH_4 measurement is ±1 ppbv and inaccuracy is estimated at ± 15 ppbv. Imprecision of the 1-Hz Picarro CO_2 measurement is ± 0.14 ppmv and inaccuracy is estimated at ± 0.12 ppmv. Imprecision of the 1-Hz QCLS CO_2 measurement is ± 0.05 ppmv and inaccuracy is estimated at ± 0.10 ppmv. All CH_4 and CO_2 measurements are reported as dry air mole fractions. For this work, CH_4 and CO_2 data from the Picarro instrument are used, and QCLS CH_4 data from May 8 are used when the Picarro instrument was not operating. The 1-Hz CO data used in this analysis were measured by vacuum ultraviolet fluorescence spectroscopy [*Holloway et al.*, 2000]. Imprecision of the 1-Hz CO data is ± 1 ppbv; inaccuracy is estimated at ± 5%. C_2 to C_5 alkanes, and their structural isomers, were measured in whole air samples [*Colman et al.*, 2001], periodically filled during flight. Imprecision of these alkane measurements is ±5%; inaccuracies are estimated at ±10%. Wind measurements were derived from various sensors aboard the NOAA P-3; the uncertainty of the 1-Hz wind speed is estimated to be ± 1 m/s. Sensors aboard the NOAA P-3 also measured relative humidity, ambient temperature, and potential temperature with an estimated 1-Hz uncertainty of ± 0.5° C, ± 0.5° C, and ± 0.5 K, respectively.

At the CalNex Pasadena ground site, located on the California Institute of Technology (Caltech) campus, measurements of C_2–C_5 alkanes were made by a gas chromatograph-mass spectrometer (GC-MS) on 5 minute integrated samples taken every half hour [*Gilman et al.*, 2010]. Imprecision of these measurements are ±8% for ethane and ±6% for propane; inaccuracy is estimated at ± 15% for each. Data from the ground site were taken between 15 May and 15 June, 2010. CH_4 was not measured at the Pasadena ground site.

Additionally, whole-air flask samples were taken twice daily at the Mount Wilson Observatory (MWO) for most days during May and June 2010, and analyzed for a variety of trace gas species, including CH_4, CO_2, CO, and hydrocarbons [*Dlugokencky et al.*, 2011; *Conway, et al.*, 2011; *Novelli et al.*, 2010]. Imprecision of the CH_4 measurement is ± 1 ppb; imprecision of the CO_2 measurement is ± 0.1 ppm; imprecision of the CO measurement is ± 1 ppbv, and inaccuracy of CO measurement is estimated to be ± 5%.

We also analyze alkane data from whole air samples taken in the L.A. basin prior to 2010. Ethane and propane were measured in whole air samples taken on four flights in L.A. aboard an instrumented National Aeronautics and Space Administration (NASA) DC-8 research aircraft during ARCTAS in June 2008 [*Simpson et al.*, 2010]. Ethane and propane were also measured on one flight in L.A. aboard the NOAA P-3 during the Intercontinental Transport and Chemical Transformation (ITCT) study in May 2002 [*Schauffler et al.*, 1999].

3. Methods

To ensure sampling from the L.A. basin, we consider aircraft data collected between 33.6 and 34.3° N latitude and 118.5 and 116.8° W longitude (Figure 1d, dashed box) in the following analysis. Aircraft data were further limited to samples taken between 1000 and 1700 PST,

between 200 and 800 m above ground, and below 1400 m above sea level, to ensure daytime sampling was within the well-mixed boundary layer, which averaged 1000 ± 300 m above ground level for the daytime L.A. flights [*Neuman et al.*, 2012]. Ground-based measurements at Pasadena were retained between 1000 and 1700 PST to ensure sampling of a well-mixed daytime boundary layer. For MWO measurements, afternoon samples, which typically occurred between 1400 and 1500 PST, were retained to capture upslope transportation from the L.A. basin [*Hsu et al.*, 2010]. Linear fits to the data presented below are orthogonal distance regressions [*Boggs et al.*, 1989] weighted by instrument imprecision [*Bevington*, 1969] (weighted ODR). The total uncertainty in the fitted slope is calculated by quadrature addition of the fit uncertainty and the measurement uncertainties.

For flux determinations, crosswind transects were flown downwind of known point sources. Enhancements of CH_4 above background levels were integrated along the flight track, and a flux was calculated using the following equation:

$$flux = v\ cos(\alpha) \int_{Z_0}^{Z_1} n(z)\,dz \int_{-y}^{y} X_m(y)\,dy \qquad (1)$$

where v cos(α) is the component of the average wind velocity normal to the flight track, n is the number density of the atmosphere, z_0 is the ground level, z_1 is the estimated boundary layer height, and X_m is the measured mixing ratio enhancement above the local background along the flight track [*White et al.*, 1976; *Trainer et al.*, 1995; *Ryerson et al.*, 1998; *Nowak et al.*, 2012]. Boundary layer heights are estimated from vertical profiles of relative humidity, ambient temperature, and potential temperature made prior to and after the crosswind transects.

We assume the plume is vertically homogeneous within the mixed layer at the point of measurement and the wind velocity is constant between emission and measurement. We estimate the uncertainty in these assumptions, combined with the uncertainties of the wind speed, wind direction, temperature, and integrated atmospheric enhancements, to be ± 50% for the plumes studied here [*Nowak et al.*, 2012]. Weighted averages of the fluxes are calculated following *Taylor* [1997]. When calculating the CH_4 flux from dairies, CH_4 variability immediately upwind of the dairies is sufficiently large to complicate interpolation from the downwind local background. To account for this, we take the weighted ODR slope of CH_4/CO immediately upwind, multiply this ratio by the measured CO downwind of the dairies, and integrate the plume CH_4 enhancement calculated from CO ($CO \times [CH_4/CO]_{upwind}$), similar to the integrations performed by *Nowak et al.* [2012]. This assumes the dairies emit a negligible amount of CO.

As with previously published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010; *Wennberg et al.*, 2012], we estimate total CH_4 emissions in the SoCAB by multiplying enhancement ratios of CH_4 to CO and CO_2 by inventory estimates of CO and CO_2 for that region:

$$E_{CH4} = \left(\frac{CH_4}{X}\right)_{ODR\ slope} \times \left(\frac{MW_{CH4}}{MW_X}\right) \times E_X \qquad (2)$$

where E_{CH4} is the emission of CH_4, X is either CO or CO_2, MW is the molecular weight, and E_X is the inventory emission value of either CO or CO_2. Although not necessarily emitted from the same sources, we assume emissions of CH_4, CO, and CO_2 are well-mixed by the time they are sampled from the NOAA P-3.

We use the following latest-available inventories for our analysis below: the 2010 CARB emissions inventory for CO projected from the base-year 2008 inventory (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php), and the 2009 CARB GHG inventory (http://www.arb.ca.gov/cc/inventory/data/data.htm). Both inventories were accessed in November 2012.

CARB projects the total 2010 annually averaged CO emissions in the SoCAB at 979 Gg CO/yr (Table 2). We use the annually averaged CARB inventory that excludes biomass burning CO emissions because no known biomass burning events were observed in the L.A. basin during CalNex. This estimate is 4% less than the summertime CO inventory without biomass burning emissions, and approximately 6% less than the annually averaged CO inventory including biomass burning emissions used by *Wennberg et al.* [2012]. To estimate 2010 CH_4 emissions in the SoCAB using the 2009 CARB GHG inventory, we follow the method used by *Wunch et al.* [2009], and take the total statewide emission of 1525 Gg CH_4/yr, less agricultural and forestry CH_4 emissions of 898 Gg CH_4/yr, then apportion the remainder by population. In 2010, the SoCAB comprised 43% of California's population (http://www.arb.ca.gov/app/emsinv/trends/ems_trends.php). However, unlike *Wunch et al.* [2009], we include SoCAB dairy emissions of 31.6 Gg CH_4/yr, calculated in section 4.3 below. Therefore, we attribute a total of 301 Gg CH_4/yr to the SoCAB based on the 2009 CARB GHG inventory (Table 2).

According to CARB's mobile source emission inventory (EMFAC 2011) for the Los Angeles County portion of the SoCAB (http://www.arb.ca.gov/jpub/webapp//EMFAC2011WebApp/emsSelectionPage_1.jsp),

mobile source CO_2 emissions remained essentially unchanged between 2009 and 2010 (39.94 versus 39.95 Tg CO_2/yr). Additionally, the statewide CARB GHG inventory for CO_2, with out-of-state electricity generation emissions removed, decreased by less than 2% between 2008 and 2009. Therefore, we assume errors due to sampling year are negligible in examining the CO_2 emission inventories in the SoCAB from 2009–2010. To estimate 2010 CO_2 emissions in the SoCAB using the 2009 CARB GHG inventory, we take the total statewide emission of 465.7 Tg CO_2/yr, subtract out-of-state electricity generation of 47.9 Tg CO_2/yr, then apportion the remainder by population. We therefore attribute 180 Tg CO_2/yr to the SoCAB using the 2009 CARB GHG inventory (Table 2). We do not compare to the Vulcan CO_2 inventory [*Gurney et al.*, 2009] because at present it is only available for the 2002 reporting year.

4. Results and Discussion

4.1. Total derived emission of CH_4 in L.A. and comparison to inventories

In this section, we use P-3 measurements of CH_4, CO, and CO_2 to calculate enhancement ratios representative of the integrated emissions from the L.A. basin. We then use tabulated CO and CO_2 emissions taken from the CARB inventories to derive total CH_4 emissions based on enhancement ratios observed in CalNex, and compare to earlier estimates of total CH_4 emissions in L.A.

Figure 1c shows known stationary sources of CH_4 in the L.A. area, which include landfills, dairies, wastewater treatment facilities, and oil fields, as well as the location of measurement sites used in this study. Dairy sources are sized by estimated CH_4 emissions from enteric fermentation, as explained in section 4.3. Landfills are sized by CH_4 emissions from the 2008 CARB GHG inventory (L. Hunsaker, personal communication, 2011).

Point sources are sized by 2009 CARB individual facility CH_4 emissions (https://ghgreport.arb.ca.gov/eats/carb/index.cfm), but do not stand out in the map due to their low CH_4 emissions relative to the landfills and dairies. Figure 1d shows the locations of daytime boundary-layer CH_4 data from the P-3, colored by observed mixing ratio, that were retained for the analysis as described previously. The largest concentrations of CH_4 were typically encountered along the mountains at the north edge of the L.A. basin, likely driven by transport of air within the basin, as typical daytime winds in the L.A. basin were from the west and southwest during May and June 2010 [*Washenfelder et al.*, 2011]. CalNex CH_4 data are plotted against observed CO in Figure 2a. Weighted ODR fits to these data resulted in derived enhancement ratios of 0.74 ± 0.04 and 0.68 ± 0.03 ppbv CH_4/ppbv CO from the NOAA P-3 and MWO, respectively. We note that the same CH_4/CO enhancement ratio of 0.74 ± 0.03 was reported by *Wennberg et al.* [2012] using the CalNex P-3 data with different selection criteria. We include box and whisker plots in Figure 2a to show that the weighted ODR fit to the data is insensitive to the relatively few data points of higher CH_4. The ratio calculated from the CARB inventory (Table 2) is 0.54 ppb CH_4/ppb CO, and is displayed for comparison.

CalNex CH_4 data are plotted against observed CO_2 in Figure 2b. The slope from a weighted ODR of P-3 data is 6.70 ± 0.01 ppb CH_4/ppm CO_2 and of MWO data is 6.60 ± 0.04 ppb CH_4/ppm CO_2. The ratio of the CARB inventories from Table 2 is 4.64 ppb CH_4/ppm CO_2, and is displayed for comparison. In this case, because CH_4 and CO_2 are measured with high precision and accuracy, the largest uncertainties in interpreting the slope as an emissions ratio are likely determined by the extent of mixing of emissions from different sources within the Los Angeles air shed. Similarly, Figure 2c shows a correlation plot of CO against CO_2.

The slope from a weighted ODR of P-3 data is 9.4 ± 0.5 ppb CO/ppm CO_2 and of MWO data is 10.4 ± 0.5 ppb CO/ppm CO_2. The ratio of the CARB inventories from Table 2 is 8.5 ppb CO/ppm CO_2, and is plotted for comparison. We estimate a ± 7.5% uncertainty in each of the CARB CO and CO_2 inventories, which is sufficient to explain the difference between the CO/CO_2 enhancement ratio measured from the NOAA P-3 and the ratio calculated from the CARB inventories. Quantitative agreement between emission ratios derived from P-3 and MWO data (Figures 2a–c) is likely due to the fact that the transport within the basin was driven by the land-sea breeze, meaning typical daytime winds in the Pasadena area near Mt. Wilson were from the southwest [*Washenfelder et al.*, 2011]. This transport, and the highest values of CH_4 and CO_2 in the P-3 data that are not seen at MWO (Figures 2a and b), also suggests that MWO preferentially samples the western part of the L.A. basin [*Hsu et al.*, 2009]. We therefore use enhancement ratios determined from the NOAA P-3 data to derive CH_4 emissions from the entire basin.

We note that the ratio of the latest CARB CO and CO_2 inventories (Table 2) are in better agreement with ambient enhancement ratios in the CalNex data than was the case for *Wunch et al.* [2009]. This is likely due to either improved CARB inventories, the present use of a basin-wide data set to determine basin-wide emission ratios, or both.

With the slopes and inventory values quantified, we next derive a CH_4 emission using equation (2). Using the CH_4/CO slope derived from the weighted ODR fit to the 2010 NOAA P-3 data and the projected 2010 CARB annually-averaged CO emission inventory in equation (2) yields an estimated SoCAB emission of 410 ± 40 Gg CH_4/yr. The stated uncertainty is the quadrature propagation of the measurement uncertainty, errors on the slope of the ODR fit to P-3

data, and an estimated uncertainty in the CARB CO inventory. We note our derived emission of 410 ± 40 Gg CH_4/yr is similar to that derived from the P-3 data by *Wennberg et al.* [2012], which was 440 ± 100 Gg CH_4/yr using different selection criteria. It is further consistent with the emission derived by *Wunch et al.* [2009] of 400 ± 100 Gg CH_4/yr, which assumed a CARB CO inventory uncertainty of 15%. We also determine CH_4 emissions using estimates of CO_2 emissions in the SoCAB. P-3 measurements of the CH_4/CO_2 enhancement ratio observed during CalNex and SoCAB CO_2 emissions inferred from the 2009 CARB GHG inventory result in a derived CH_4 emission rate of 440 ± 30 Gg CH_4/yr, with the stated uncertainties determined by quadrature propagation of the measurement uncertainty, errors on the slope of the ODR fit to P-3 data, and an estimated uncertainty in the CARB CO_2 inventory. This value, based on the CO_2 inventory, is consistent with that derived using P-3 measurements and the CO inventory, further supporting both our assessment of uncertainties in the CARB CO and CO_2 inventories, and our assumption of sampling well-mixed emissions in the SoCAB, since any outlying CH_4 data do not affect the overall emission estimates significantly.

The derived 2010 top-down SoCAB CH_4 emission of 410 and 440 Gg CH_4/yr reported here using the CARB CO or CO_2 inventories, respectively, are in quantitative agreement, in contrast to that reported for 2008 [*Wunch et al.*, 2009]. The 2010 estimates are a factor of 1.35 to 1.45 greater than the modified population-apportioned 2009 CARB GHG inventory value of 301 Gg CH_4/yr (Table 2). A concurrent inverse modeling study by *Brioude et al.* [2012] has found no statistical difference between the total SoCAB CO emissions reported by CARB for 2010 and a top-down approach that estimated CO emissions in the SoCAB region using the same CO measurements used in this paper. For this reason, and for consistency with published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010; *Wennberg et al.*, 2012],

we use 410 ± 40 Gg CH_4/yr from the top-down CH_4 assessment based on 2010 P-3 measured CH_4/CO enhancement ratios and the CARB CO inventory for the remainder of our analysis.

4.2. Methane emissions from L.A. basin landfills

Landfills are the largest non-fossil fuel CH_4 emission source in the bottom-up inventories compiled by *Hsu et al.* [2010] and by *Wennberg et al.* [2012], but these two studies disagree on the magnitude of this source. *Hsu et al.* [2010] estimated annual emissions from landfills totaled 90 Gg CH_4/yr from the Los Angeles County portion of the South Coast Air Basin. *Wennberg et al.* [2012] reported landfill emissions of just 86 Gg CH_4/yr for the entire South Coast Air Basin. However, that number is too low due to an error in their gridded landfill emissions inventory [*P. Wennberg,* personal communication, 2012] and is discarded in the following analysis.

In the CARB GHG inventory, CH_4 emissions are calculated for individual landfills using methods prescribed by the IPCC and summed over all landfills to estimate a statewide total. Annual CH_4 emission values for individual landfills were obtained directly from CARB [*L. Hunsaker,* personal communication, 2011] to facilitate direct comparison to the P-3 data from CalNex. We use the P-3 data to calculate emissions from two of the largest CH_4-emitting landfills in the statewide GHG inventory, both of which are located in the SoCAB.

The first landfill results we examine are from the Olinda Alpha landfill (33.934° N, 117.841° W) in Brea, Orange County, California. The NOAA P-3 flew five daytime boundary-layer transects on five different days downwind of this landfill (Figure 3), and a CH_4 emission flux was determined for each transect using equation (1). The results are summarized in Table 3.

For the three transects when both the WS-CRDS and QCLS CH_4 instruments were sampling ambient air, flux determinations using these independent CH_4 measurements agreed within 3%. In these cases, the flux was averaged and reported in Table 3. Three nearby CH_4 point sources are identified in the 2009 CARB GHG inventory: an oil and gas field power plant, which burns natural gas for fuel; the landfill power plant at Olinda Alpha, which burns landfill gas for fuel; and general stationary combustion from the landfill operations. Inventory data suggest that these three sources together emit between 0.0004 and 0.0015 Gg CH_4/yr, negligible amounts relative to CH_4 emitted directly from the landfill. On 19 May, the NOAA P-3 sampled plumes from the nearby oil and gas power plant and the landfill's power plant, both of which burn natural gas as fuel (Figure 3c). A large spike in CO_2, some CH_4, and perhaps a small amount of CO were encountered in the landfill power plant plume. However, downwind of the landfill in the large plume of CH_4, the CO_2 enhancement does not stand out significantly above the background variability. Therefore, our analysis of P-3 data supports the conclusion from the inventory that landfill CH_4 emissions dominate the observed plume enhancements downwind of Olinda Alpha landfill. Using NOAA P-3 CH_4 data from all five transects, we directly calculate a weighted average CH_4 emission flux via equation (1) of $(1.49 \pm 0.35) \times 10^{25}$ molecules/s, equal to 12.5 ± 2.9 Gg CH_4/yr assuming a constant emission, where the weights are the 50% uncertainty of each determination. For comparison, the CARB GHG inventory emission estimate from the Olinda Alpha landfill is 11.0 Gg/yr for 2008, showing agreement within the errors of the direct estimate using P-3 airborne data.

The second landfill results we examine in-depth are from the Puente Hills landfill (34.020° N, 118.006° W) in City of Industry, Los Angeles County, California. Of all California landfills, Puente Hills is the largest emitter of CH_4 in the 2008 CARB GHG inventory.

Nearby sources of CH_4 in the 2008 CARB GHG inventory include the Puente Hills power plant (0.00045 Gg CH_4/yr) and the Savage Hills Canyon landfill (1.1 Gg CH_4/yr), both of which are small relative to the CARB GHG inventory of 39 Gg CH_4/yr emission rate for Puente Hills. The NOAA P-3 conducted three daytime boundary layer plume transects from which we determine an average emission flux of $(4.06 \pm 1.18) \times 10^{25}$ molecules/s, which extrapolates to 34.0 ± 9.9 Gg CH_4/yr assuming a constant emission (Table 3). Similar to the findings for Olinda Alpha, the CARB GHG inventory of 39 Gg CH_4/yr for the Puente Hills landfill is in agreement within the errors of the direct estimate using P-3 airborne data.

Quantitative agreement between CH_4 flux estimates from the NOAA P-3 and the 2008 CARB GHG inventory for these two examples supports the use of that inventory to quantify total CH_4 emissions from landfills in the South Coast Air Basin. According to the 2008 CARB GHG inventory, CH_4 emissions from landfills totaled 117 Gg CH_4/yr in the L.A. County portion of the SoCAB, 30% higher than the 90 Gg CH_4/yr for the same geographic area using the CARB GHG inventory in 2008 reported by *Hsu et al.* [2010], which we attribute to different versions of the CARB GHG inventory.

The 2008 CARB GHG inventory further predicts an emission from landfills of 164 Gg CH_4/yr for the entire SoCAB. On the basis of the agreement with the CARB inventory described above for the emission rates from the two landfills quantified directly by the CalNex P-3 data (50 Gg CH_4/yr, or 30% of the inventory total for the SoCAB), we assume the remaining CARB landfill CH_4 emission estimates are accurate.

4.3. Methane emissions from L.A. basin dairies

Salas et al. [2008] published dairy locations in California for the year 2005, with an estimate of dairy cow population for each. The locations are plotted as filled yellow circles in Figure 1c, and sized by the expected CH_4 emission from enteric fermentation according to the 2009 CARB GHG inventory (144 kg CH_4 per cow per year). According to *Salas et al.* [2008], all dairies in San Bernardino and Riverside counties were also located in the SoCAB, and 87% of the dairy cows in the SoCAB in 2005 were located in the Chino area (the large grouping of dairies in Figure 1c). The Chino-area dairy operations, which at one time were distributed across the Riverside-San Bernardino county line in satellite images, now appear to be located mainly in San Bernardino County as the Riverside dairies have been converted to residential neighborhoods (*e.g.*, see Google Earth historical imagery since 2000). This declining number of dairies is confirmed by the United States Department of Agriculture (USDA) (http://www.nass.usda.gov/Statistics_by_State/California/Publications/County_Estimates/201005lvscef.pdf), which reports a decrease in dairy cows in San Bernardino and Riverside Counties from 200,000 head in 2005 to 137,500 head in 2010. In addition to dairy cows, dairies also stock immature heifers. Further, there are beef operations in the SoCAB, but these are negligible compared to the San Bernardino and Riverside dairy populations. According to the USDA, there were a total of 431,000 cattle in San Bernardino and Riverside counties in 2005, and 295,000 cattle in 2010. For both years, dairy cows represented approximately 46.5% of the cattle population in the SoCAB. From these dairy and cattle populations, we construct a bottom-up emissions inventory for the SoCAB using the same emission factors as the CARB GHG inventory.

We begin with CH_4 emissions from enteric fermentation. We assign to each of the 137,500 dairy cows in the SoCAB an emission factor of 144 kg CH_4/yr. We assume the remaining 157,500 head are dairy replacements, and assign each an emission factor of 57.7 kg CH_4/yr, or the average emission factor for 0–1 and 1–2 year old dairy replacements in the CARB GHG inventory. We calculate a total of 28.9 Gg CH_4/yr emitted solely from enteric fermentation in the SoCAB.

In addition to enteric fermentation, manure management practices have a substantial effect on CH_4 emissions from livestock operations. In the L.A. basin, dairies typically practice solid storage (http://www.aqmd.gov/rules/doc/r1127/pr1127_task1rpt_20020101.pdf and http://www.arb.ca.gov/planning/sip/sjv_report/addtl_resources.pdf), which emits relatively low levels of CH_4 (17 kg/yr per cow) according to the 2009 CARB GHG inventory. The tradeoff for this practice is that it emits larger amounts of NH_3 than other types of manure management (http://www.epa.gov/ttn/chief/ap42/ch09/draft/draftanimalfeed.pdf). Therefore, if we attribute dry manure management emissions to the SoCAB dairy cow population, and the dry lot emission rate of 2.1 kg CH_4/yr for the remaining heifers, we get an additional 2.7 Gg CH_4/yr from dairy operation manure management in the SoCAB. This results in a total of 31.6 Gg CH_4/yr from enteric fermentation and manure management for the SoCAB dairy operations. This is the emission from agriculture and forestry that we add back into the population-apportioned CARB CH_4 inventory above (Table 2).

Our estimate of 31.6 Gg CH_4/yr, based on inventory data, is less than half of the 76 Gg CH_4/yr estimated by *Wennberg et al.* [2012]. We attribute this difference in bottom-up inventories to the different assumptions of manure management practices.

Wennberg et al. [2012] scaled total California CH_4 emissions by livestock population, which also assumes the manure management practices from the San Joaquin Valley apply to the L.A. basin. For example, the anaerobic lagoons more commonly used in the San Joaquin Valley emit 325 kg CH_4 per cow per year according to the 2009 CARB GHG inventory, significantly higher than 17 kg CH_4 per cow per year from dry manure management practices typical of the L.A. basin.

Nowak et al. [2012] used P-3 data from CalNex to derive emissions of ammonia (NH_3) from dairy farms in the Chino area. From NOAA P-3 measurements, we determine a CH_4 flux from the Chino-area dairies for the same three downwind transects analyzed by *Nowak et al.* [2012]. Using the Chino to SoCAB population apportionment by *Salas et al.* [2008], we expect these same Chino-area dairies to emit approximately 28 Gg CH_4/yr. CH_4 fluxes determined from equation (1) range from 24 ± 12 to 88 ± 44 Gg CH_4/yr, and the average of the three transects is 49 ± 25 Gg CH_4/yr. This value derived from airborne flux determination lies between the 28 Gg CH_4/yr calculated from the inventory assuming dry manure management practices described above, and the estimate by *Wennberg et al.* [2012] of 76 Gg CH_4/yr (less livestock emissions from the SoCAB that are not in the Chino area) assuming mainly wet management practices. We attribute the differences to actual practices in the region, which are likely a mixture of the two manure management approaches. Satellite images of the area show what appear to be several anaerobic lagoons near Chino, California. Our flux determination is therefore consistent with our bottom-up CH_4 emission inventory, with room for a mixture of manure management practices, including some anaerobic lagoons, in the L.A. basin.

4.4. Spatial distribution of methane sources

Townsend-Small et al. [2012] concluded that the CH_4 emissions in the L.A. region had a stable isotope ratio similar to that of fossil-fuel CH_4. This conclusion was based on measurements made at the Mt. Wilson Observatory. A back-trajectory [*White et al.*, 2006; http://www.esrl.noaa.gov/psd/programs/2010/calnex/traj/] from MWO for 5 August 2009, the specific day that *Townsend-Small et al.* [2012] used to determine the excess CH_4 stable isotopic ratio, shows the prevailing winds to MWO were from the southwest, or from downtown L.A. and the coast west of downtown L.A. The trajectory tool also shows winds from the eastern basin on the previous day, which was excluded by *Townsend-Small et al.* [2012] due to lower correlation between the excess CH_4 and $\delta^{13}C$. We conclude that the MWO data interpreted by *Townsend-Small et al.* [2012] were dominated by emissions from the western basin only, and were not influenced by emissions from either the largest landfills (Puente Hills and Olinda Alpha), or from the dairies in the eastern part of the L.A. basin. This spatially-biased sampling is consistent with their conclusion that landfills do not contribute significantly to the total atmospheric CH_4 burden in L.A.

Evidence for the heterogeneous spatial distribution of CH_4 sources in the SoCAB can be seen in the NOAA P-3 data. Figure 4 shows that the correlation of ethane with CH_4 is dependent on the sample location in the L.A. basin. Also shown in Figure 4 is the slope used by *Wennberg et al.* [2012] to represent the ethane/CH_4 ratio (16.5 ± 2.5 ppt ethane/ppb CH_4) in pipeline-quality dry natural gas from the Southern California Gas Company (SoCalGas), the major provider of natural gas to the SoCAB, for 2010.

The chemical data in Figure 4 reflect the known source types shown on the map in Figure 1c: the large CH_4 sources in the eastern L.A. basin, primarily landfills and dairies, are not significant sources of ethane relative to CH_4.

We can reconcile the conclusions of *Townsend-Small et al.* [2012] and *Wennberg et al.* [2012] with the CARB GHG inventory by noting that fossil fuel CH_4 emissions predominate in the western basin, and that landfill and livestock CH_4 emissions predominate in the eastern basin. However, in contrast to the findings of *Wennberg et al.* [2012], we find that natural gas leaks from the SoCalGas and in-home pipelines are not the only possible source of fossil fuel CH_4 to the western basin, as described below.

4.5. Light alkane emissions from local natural gas production

Los Angeles was one of only three out of 28 cities characterized by propane and ethane levels within 10% of one another in the atmosphere [*Baker et al.*, 2008], consistent with an enhanced propane source term in L.A. Figure 5 shows correlations of propane vs. ethane in whole-air samples from various aircraft projects in the Los Angeles region (ITCT 2002, ARCTAS 2008, and CalNex 2010), as well as measurements from the CalNex Pasadena ground site in 2010. Also plotted are lines representing the composition ratios of other possible sources of ethane and propane in Los Angeles.

The L.A. basin is home to oil and gas operations (see Figure 1c); the composition ratios depicting possible emissions from local natural gas (gray lines) and local geologic seeps (salmon lines) in Figure 5 are those reported by *Jeffrey et al.* [1991]. The lower propane content relative to ethane seen in the seeps (*e.g.*, the La Brea tar pits) compared to the local natural gas is attributed to near-surface microorganisms forming shorter-chain alkanes from longer-chain

alkanes during the time the natural gas migrates toward the surface [*Jeffrey et al.*, 1991]. The average propane/ethane ratio for processed gas in SoCalGas pipelines [*Wennberg et al.*, 2012] is plotted as a dashed black line. Pipeline-quality dry natural gas has a low propane/ethane ratio because the natural gas has been processed (*i.e.*, the higher alkanes have been removed from the natural gas) before distribution. The SoCalGas ratio is representative of natural gas piped in from out of state (*e.g.*, from Texas, Wyoming, and Canada); approximately 90% of natural gas used in California is imported (http://www.socalgas.com/regulatory/documents/cgr/2010_CGR.pdf). The on-road emissions are taken from a San Francisco Bay-area tunnel study by *Kirchstetter et al.* [1996], who reported a vehicular emission ratio of 0.13 mol propane/mol ethane roughly similar to those by *Fraser et al.* [1998] (0.27 mol propane/mol ethane) and by *Lough et al.* [2005] (0.06 – 0.18 mol propane/mol ethane). Vehicle engine exhaust typically contains small, decreasing amounts of CH_4, ethane, and propane due to incomplete combustion, as gasoline and diesel fuel do not contain significant amounts of these light alkanes. The on-road emissions, local geologic seeps, and the pipeline-quality dry natural gas from SoCalGas contain 3–5 times more ethane than propane, and therefore cannot alone explain the ambient ratios measured in the L.A. basin. The propane and ethane composition of unprocessed natural gas from local wells, on the other hand, closely matches the SoCAB ambient measurements from three aircraft campaigns, the CalNex ground site measurements, and the *Baker et al.* study [2008]. Propane and ethane were also typically enhanced at the same time, with the exception of one sample with elevated propane near the Long Beach area (Figure 1e).

The data in Figure 5 suggest that local oil and gas wells contribute significantly to the atmospheric propane burden in the SoCAB. However, *Wennberg et al.* [2012] invoked a large

source of propane from fugitive losses from the liquefied petroleum gas (LPG) industry (*i.e.*, propane tanks), in addition to leaks from the pipeline-quality dry natural gas distribution system in the L.A. basin. This would be consistent with past works that have found significant fugitive losses of propane in other cities, such as Mexico City [*Blake and Rowland*, 1995]. We therefore extend our analysis to incorporate ethane, propane, and C_4 (*n*- and *i*-butane) and C_5 (*n*- and *i*-pentane) isomers to better attribute and quantify the sources of light alkanes and CH_4 to the SoCAB atmosphere. Light alkanes are plotted in Figure 6, with lines depicting the composition of natural gas in SoCalGas pipelines [*Wennberg et al.*, 2012] and of on-road emissions [*Kirchstetter et al.*, 1996]. We neglect chemical processing of these long-lived alkanes ($\tau \geq 3$ days at OH = 1×10^6 molecules/cm^3) as we find no detectable difference between daytime and nighttime enhancement ratios relative to CO, similar to the findings of *Borbon et al.* [2013] for *n*-butane and CO at the CalNex Pasadena ground site. Atmospheric enhancement ratios of propane, *n*-butane, and *i*-butane (Figures 6b–d) relative to ethane are consistent with emissions having the composition of local natural gas [*Jeffrey et al.*, 1991]. On-road emissions do not appear to contribute significantly to the CH_4, ethane, and propane in the L.A. atmosphere, and pipeline-quality dry natural gas and/or local geologic seeps do not appear to contribute significantly to the propane and *n*-butane relative to ethane in the L.A. atmosphere. Based on these observations, we conclude that the local natural gas industry contributes a significant fraction to the total atmospheric C_2-C_4 alkane abundances, including propane, in the L.A. basin. We infer CH_4 emissions from the local natural gas industry are non-negligible as well, as discussed below.

4.6. Source Attribution

Here we quantify total emissions of C_2–C_5 alkanes in the L.A. basin by multiplying their observed enhancement ratios to CO by the CARB SoCAB emission inventory for CO. Figure 7 shows C_2–C_5 alkanes plotted versus CO with their respective ODR fits. The slopes from these fits are used in equation (2) along with the projected 2010 CARB CO inventory to calculate annual alkane emissions in the SoCAB. We assume the slopes represent a direct emission with no chemical aging. These emissions are listed in the right-most column of Table 4. Also listed in Table 4 are the estimated contributions from mobile sources in the SoCAB, using C_1–C_5 to CO emission ratios from *Kirchstetter et al.* [1996] (modified as discussed below) and CO emissions from the mobile sources category in the projected 2010 CARB CO inventory, equal to 920 Gg CO/yr, in equation (2).

Wennberg et al. [2012] attributed the inventory CH_4 shortfall [*Wunch et al.*, 2009; *Hsu et al.*, 2010] by ascribing much of the CH_4 and ethane enhancements to fugitive losses of processed pipeline-quality dry natural gas. They further suggest the majority of atmospheric propane is due to LPG industry/propane tank fugitive losses. Here, we consider other possible explanations of the sources of CH_4 and light alkanes in the L.A. basin for the following two reasons. First, the source attribution by *Wennberg et al.* [2012] leaves little room for CH_4 emissions from landfills, wastewater treatment plants, and dairies in the L.A. basin. This solution seems unlikely based on direct emissions flux estimates using the P-3 data downwind of landfills and dairies in the SoCAB, as described above. Second, the attribution by *Wennberg et al.* [2012] would leave a shortfall in both *n*- and *i*-butane emissions that cannot be explained by gasoline evaporation or emissions from mobile sources.

We use a multivariate approach based on a linear combination of the CH_4 and light alkane compositions from known sources in order to attribute and quantify total CH_4 and C_2–C_5 alkane emissions in the South Coast Air Basin.

We include 7 different source types (sectors) with distinct and known CH_4 and C_2–C_5 alkane compositions (Figure 8) in the following analysis: 1) Leaks of processed dry natural gas from pipelines, and/or emissions from local geologic seeps (this approach cannot distinguish between pipeline-quality dry natural gas and local seeps); 2) CH_4-dominated emissions, such as from landfills, wastewater treatment plants, and dairies; 3) Leaks of unprocessed, local natural gas; 4) Leaks of liquefied petroleum gas from propane tanks; 5) On-road combustion emissions from mobile sources; 6) Emissions of CH_4 and C_2–C_5 alkanes in the SoCAB from other source sectors; and 7) Evaporative emissions from gasoline. These are described briefly below.

1. The South Coast Air Basin contains 14.8 million people, and SoCalGas delivers approximately 11 Tg/yr of natural gas to the Los Angeles area. Additionally, the Earth's natural degassing is a known source of CH_4, ethane, and propane to the atmosphere [*Etiope et al.*, 2008; *Etiope and Ciccioli*, 2009], and the L.A. basin contains abundant geologic hydrocarbon reserves [*Jeffrey et al.*, 1991]. We group fugitive losses from processed pipeline-quality dry natural gas with the emissions from local geologic seeps because the C_1–C_4 emissions from these sources are not sufficiently different to be treated separately in our linear combination analysis (illustrated by the similarity in slopes of the dashed black and salmon-colored lines in Figure 6).

Both pipeline-quality dry natural gas and local seep emissions contain similar amounts of CH_4 and ethane relative to one another, and have less C_3–C_5 alkanes relative to ethane than local, unprocessed natural gas. For pipeline-quality dry natural gas, most C_{3+} alkanes are removed during the processing stage, which is typically done close to the source, which for ~90% of the natural gas used in California is in Canada, Wyoming, and/or Texas. For local seeps, most C_{3+} alkanes are either preferentially adsorbed in shallow sediments compared to CH_4, or biodegraded by microbes in the earth's crust during the seepage of local natural gas to the surface [*Jeffrey et al.*, 1991]. We use SoCalGas samples of pipeline-quality natural gas from 2010 [*Wennberg et al.*, 2012] to represent this source, and estimate the uncertainty of the composition at 15%.

2. CH_4-dominant emission sources, which for this analysis include landfills, wastewater treatment plants, and livestock, emit CH_4 but no significant amounts of C_2–C_5 alkanes. This is represented in our analysis as a unit vector containing only CH_4.
3. From 2007–2009, the oil and gas industry in the L.A. basin produced roughly 12–13 billion cubic feet of natural gas per year, mostly associated gas from oil wells (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). We use an average of the samples reported by *Jeffrey et al.* [1991] weighted by 2009 gross natural gas production per field, and estimate the uncertainty of this composition at 25%.
4. Two types of LPG are sold in the Los Angeles area: one is almost completely composed of propane, the other has traces of *n*- and *i*-butane (http://www.arb.ca.gov/research/apr/past/98-338_1.pdf).

We use the ratios reported by *Blake and Rowland* [1995] from direct analysis of LPG in Los Angeles, which is consistent with an average of the two types of LPG sold in L.A, and estimate the uncertainty of the composition at 10%.

5. On-road combustion emissions are modified from the work of *Kirchstetter et al.* [1996] by multiplying emission ratios of alkanes to CO by the 925 Gg CO/yr from on-road sources in the projected 2010 CARB CO inventory. The C_4–C_5 emissions represent unburned fuel and are typically proportional to the fuel composition; the C_1–C_3 emissions typically represent incomplete combustion products. To account for differing fuel compositions since the time of the *Kirchstetter et al.* [1996] study, the *i*- and *n*-butane emissions calculated for mobile sources in the SoCAB (Table 4) have been scaled to the *i*-pentane emissions based on their relative abundance in gasoline [*Gentner et al.*, 2012].
6. There are additional sources of light alkanes in the SoCAB. We use the 2010 CARB speciated inventory for total organic gases (http://arb.ca.gov/ei/speciate/interopt10.htm) and projected 2010 total organic gas emissions (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php) for the SoCAB to estimate emissions of light alkanes not specified in other source sectors. These include emissions from aerosol spray cans and other consumer products, coatings and solvents, adhesives and sealants, and fiberglass and plastics manufacturing. For example, propane, *n*- and *i*-butane are commonly used as propellants in aerosol spray cans, having replaced CFCs in the United States in the 1970s (*e.g.*, CARB estimates 0.6 Gg of aerosol antiperspirant vapors were emitted to the SoCAB in 2010, of which 0.14 Gg, 0.03 Gg, and 0.15 Gg were propane, *n*-, and *i*-butane, respectively).

These emissions are summed and listed in the "CARB other" column in Table 4. Emissions from natural gas leaks, petroleum refining, petroleum marketing (gas stations), landfills and composting, and mobile sources are not included in these totals, because they are accounted for elsewhere in other source sectors. We estimate a 25% uncertainty in the "CARB other" inventory.

7. Emissions ratios from evaporated gasoline were calculated from ten gasoline samples from five Pasadena gas stations in the summer of 2010, weighted by estimated sales of 80% regular and 20% premium [*Gentner et al.*, 2012]. Uncertainties are those reported by *Gentner et al.* [2012].

First, we start with estimated annual C_1–C_5 emissions in the SoCAB (right-most column of Table 4), then subtract modified on-road emissions [*Kirchstetter et al.*, 1996] and projected emissions of C_1–C_5 alkanes from other sources (source sector 6, above). Next, we place the remaining source sector characteristics into a matrix and solve for the fraction each source contributes to the remaining alkane observations for the L.A. basin based on each source's relative abundances of various light alkanes. The matrix has five columns representing the five remaining source sectors, and seven rows containing C_1–C_5 alkanes. We solve the equation [*e.g.*, see §4.2 *Kim et al.*, 2011]

$$\mathbf{A}_{i,j}\ \mathbf{x}_j = \mathbf{b}_i \qquad (3)$$

where $\mathbf{A}_{i,j}$ is a matrix of the C_1–C_5 alkane composition, i, for the source sectors, j, defined above; x_j is the fraction each source contributes to the total observed emissions, and b_i is the total observed emission of alkane i minus the contributions from the mobile and "other" source sectors (Table 4). The columns of the matrix **A** are proportional to the first five columns of

Table 4. We use LAPACK (http://www.netlib.org/lapack/) to solve for the linear least squares solution that minimizes ($\mathbf{Ax} - \mathbf{b}$). Uncertainties in the derived $\mathbf{x}_j$ are estimated by a sensitivity study, where we run the solution 1,000,000 times by randomly varying $\mathbf{A}_{i,j}$ and $\mathbf{b}_i$ according to their estimated uncertainties, then use the standard deviation of the 1,000,000 $\mathbf{x}_j$ determinations to estimate the uncertainty in the source attribution fraction. The source attribution fractions and their uncertainties are multiplied by the total estimated SoCAB emission for each alkane, then are summed with the uncertainties added in quadrature. CH_4 and C_2–C_5 alkane emissions totals, their uncertainties, and the contributions from each source type are given in Table 4. The source attribution solution solves the observed SoCAB alkane emission to within each alkane's emission uncertainty.

Our modeled source attribution differs from the alkane source distribution in the L.A. basin as set forth by *Wennberg et al.* [2012]. From a total calculated source of 410 ± 40 Gg CH_4/yr in the SoCAB, we determine that 47% comes from leaks of processed pipeline-quality dry natural gas and/or from local geologic seeps; 44% of the CH_4 comes from the sum of landfill, wastewater treatment, and dairy emissions; 8% from the leaks of unprocessed natural gas from production in the western L.A. basin; and 1% from mobile sources. The attribution is presented graphically in Figure 8. Figure 8a displays the total SoCAB emissions as a black horizontal line in each panel, with contributions from the different source sectors given below the line by the filled bars. Figure 8b shows the proportion that each source sector contributes to the derived total emissions of each alkane.

Our analysis attributes CH_4 emissions of 192 ± 54 Gg CH_4/yr to leaks of pipeline-quality dry processed natural gas and/or leaks from local geologic seeps, but does not distinguish further between these two different sources. This value is nearly a factor of 5 greater than the population-apportioned 2009 CARB GHG emissions inventory estimate of 40 Gg CH_4/yr lost from natural gas pipelines in the SoCAB. Our estimate of 192 Gg CH_4/yr is less than the maximum emission of 400 ± 150 Gg CH_4/yr estimated by *Wennberg et al.* [2012]. Our estimate would represent approximately 2% of the natural gas delivered to customers in the SoCAB and, including storage and deliveries to customers outside the SoCAB, 1% of the gas flowing into the basin [*Wennberg et al.*, 2012]. These percentages would decrease linearly with any CH_4 emissions attributed to local geologic seeps. *Farrell et al.* [*in press*, 2012] estimate up to 55 Gg CH_4/yr are emitted from the La Brea Tar Pits in western L.A. County alone; if accurate, this would imply pipeline leaks of only 0.7% of the gas flowing into the basin, or a factor of at least two lower than the 2% proposed by *Wennberg et al.* [2012].

Our analysis attributes 182 ± 54 Gg CH_4/yr in the SoCAB to emissions from landfills, wastewater treatment, and dairies. SoCAB landfills account for 164 Gg CH_4/yr in the 2008 CARB GHG inventory, a value supported by our analysis in section 4.2. In section 4.3, we estimated in a bottom-up inventory that SoCAB dairies emitted 31.6 Gg CH_4/yr. *Wennberg et al.* [2012] estimated an emission of 20 Gg CH_4/yr from wastewater treatment. These independent estimates sum to 216 Gg CH_4/yr and are consistent with our source apportionment using NOAA P-3 data.

CH_4 emissions of 31.9 ± 6.5 Gg CH_4/yr are ascribed to leaks of local, unprocessed natural gas, and would represent 17% of the local production in 2009, the latest year for which data are available (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). This number assumes a CH_4 composition of 72.5% by volume for natural gas produced in the South Coast Air Basin, which is calculated as an average from the samples reported by *Jeffrey et al.* [1991] weighted by 2009 production. Our derived value of 17%, although a surprisingly high amount of local production, is consistent with a nascent bottom-up estimate under way at CARB. A new bottom-up inventory survey, conducted by CARB for the calendar year 2007 but not yet incorporated into the official GHG inventory, indicates that 109 Gg CH_4/yr, since revised to 95.5 Gg CH_4/yr [*S. Detwiler,* personal communication, October 2012], were emitted throughout California by the oil and gas industry via combustion, venting, and fugitive losses (table 3-1, http://www.arb.ca.gov/cc/oil-gas/finalreport.pdf). This updated value is a factor of 2.5 larger than the current CARB GHG inventory tabulation of 38 Gg CH_4/yr from oil and gas extraction for 2007 in California. CH_4-specific emissions for the South Coast Air Management District in the new CARB survey report show 24.6 Gg CH_4/yr were emitted in the SoCAB [S. Detwiler, personal communication, October 2012]. According to the survey, emissions in the SoCAB accounted for 26% of the revised statewide total oil and gas operations CH_4 emission in 2007, despite accounting for only 4.4% of statewide natural gas production in the basin that year (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). Thus, the survey responses suggest a CH_4 leak rate of 12% of local production in the L.A. basin.

Thus, our estimate of CH_4 emissions from local natural gas for 2010 based on P-3 data from CalNex is within a factor of 1.5 of the CARB bottom-up inventory currently in development based on the 2007 survey. According to the survey, other oil and gas producing regions in California show smaller CH_4 loss rates than that from the SoCAB. For instance, statewide losses of CH_4 represent approximately 2.1% of statewide production, and CH_4 losses from the San Joaquin Air Quality District represent approximately 1.4% of production (from Oil and Gas Districts 4 and 5). This indicates that losses from natural gas production are proportionally larger in the L.A. basin than elsewhere in the State of California.

A propane emission of 6.6 ± 2.9 Gg/yr from LPG/propane tanks would represent approximately 1% of sales (http://www.aqmd.gov/ceqa/documents/2012/aqmd/finalEA/PAR1177/1177_FEA.pdf), which is less than the ~4% calculated by *Wennberg et al.* [2012], and closer to the 0.6% estimated from the document cited.

Finally, our analysis suggests a resolution to the discrepancies noted above between previous top-down assessments and the bottom-up inventory calculations for CH_4 in the SoCAB [*e.g.*, *Wunch et al.*, 2009; *Hsu et al.*, 2010; *Townsend-Small et al.*, 2012; *Wennberg et al.*, 2012]. We conclude the most probable source for the excess atmospheric CH_4 is likely due to a combination of primarily leaks, not accurately represented in the current CARB GHG inventory, from natural gas pipelines and urban distribution systems and/or from local geologic seeps, and secondarily leaks of unprocessed natural gas from local oil and gas production centered in the western L.A. basin.

This finding is based on the characteristic enhancement ratios of CH_4 and the various C_2–C_5 alkanes consistently observed in the L.A. atmosphere, and is further supported by the spatial information provided by P-3 samples during CalNex. Finally, the updated values for local oil and gas industry emissions in the recent GHG survey commissioned by CARB, when incorporated fully into the official CARB GHG record, will likely help to reduce this long-standing discrepancy between top-down assessments and bottom-up inventories.

5. Conclusions

We use aircraft measurements of CH_4, CO, and CO_2 during the CalNex field campaign to show that emissions of CH_4 to the L.A. basin are greater than can be explained by official state bottom-up inventories apportioned by population, consistent with published work. The ratio of the CARB CO and CO_2 inventories is in better agreement with our measurements of CO/CO_2 in the Los Angeles atmosphere than was the case for the analysis by *Wunch et al.* [2009], which we attribute either to improved CARB inventories, the present use of a basin-wide data set to determine basin-wide emission ratios, or both.

From crosswind plume transects downwind of the two largest landfills in the basin, we determine CH_4 fluxes that are consistent with the 2008 CARB GHG inventory values, which total 164 Gg CH_4/yr emitted from all landfills in the South Coast Air Basin. CH_4 emission fluxes were also determined for Chino-area dairies in the eastern L.A. basin. Flux estimates from these dairies ranged from 24 ± 12 to 87 ± 44 Gg CH_4/yr, and the average flux is consistent with a revised bottom-up inventory originally compiled by *Salas et al.* [2008] and with previous inventory estimates [*Wennberg et al.*, 2012].

Finally, we present a top-down assessment of C_2–C_5 alkane sources in the L.A. basin, then apportion CH_4 and the C_2–C_5 alkanes to specific source sectors in the region. Using this source apportionment approach, we estimate that 32 ± 7 Gg of CH_4/yr, or 8% of the total CH_4 enhancement observed in the SoCAB during CalNex, came from the local oil and gas industry. This number represents approximately 17% of the natural gas produced in the region, within a factor of 1.5 of that calculated from a recent survey that will be used to update the CARB bottom-up inventory. We estimate 182 ± 54 Gg CH_4/yr are emitted by landfills, dairies, and wastewater treatment, which is consistent with bottom-up inventories, and 192 ± 54 Gg CH_4/yr are emitted of processed pipeline-quality dry natural gas and/or from geologic seeps in the region. We further conclude that leaks of processed pipeline-quality dry natural gas and/or local geologic seeps, and unprocessed natural gas from local oil and gas production are the most likely major contributors to the previously noted discrepancy between CH_4 observations and State of California inventory values for the South Coast Air Basin. Our findings suggest that basin-wide mobile studies targeting CH_4 and C_2–C_5 alkane emissions from natural gas pipelines and urban distribution systems, geologic seeps, and local oil and gas industry production sites would be useful to further distinguish the sources of CH_4 in the L.A. basin.

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Table 1. Summary of past studies investigating CH_4 emissions in the L.A. basin.

Study	Time of study	Geographic area	Percentage of California population in geographic area	CH_4 Emission (Gg/yr)	Inventory referenced	Bottom-up CH_4 emission inventory (Gg/yr)
Wunch et al. [2009]	August 2007 – June 2008	SoCAB	43%	400 ± 100	CARB CO 2007	260[b]
				600 ± 100	(CARB CO_2 2006 + EDGAR CO_2 2005)/2	
Hsu et al. [2010]	April 2007 – May 2008	L.A. County ∩ SoCAB	27%	200 ± 10	CARB CO 2007	140
Wennberg et al. [2012]	April 2007 – May 2008	SoCAB	43%	380[a] ± 100	CARB CO 2007	---
	June 2008	SoCAB	43%	470 ± 100	CARB CO 2008	---
	May 2010 – June 2010	SoCAB	43%	440 ± 100	CARB CO 2010	---

[a] *Wennberg et al.* [2012] recalculated the data reported by *Hsu et al.* [2010] to estimate a CH_4 emission from the entire SoCAB.

[b] *Wunch et al.* [2009] apportioned the statewide CARB GHG inventory for CH_4, less agriculture and forestry emissions, by population

Table 2. Inventories used in current analysis

Emission	Inventory	Year	Geographic Area
180 Tg CO_2/yr	CARB GHG[a]	2009	SoCAB[c]
979 Gg CO/yr	CARB[b]	2010	SoCAB[c]
301 Gg CH_4/yr	CARB GHG[a]	2009	SoCAB[c]

[a] 2009 CARB CO_2 and CH_4 emissions (http://www.arb.ca.gov/cc/inventory/data/data.htm)

[b] projected 2010 CARB CO emissions (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php)

[c] statewide inventory apportioned by SoCAB population

Table 3. Landfill emission fluxes determined aboard the NOAA P-3 in 2010 from downwind plume transects.

Landfill	Transect Date	Flux, 10^{25} molecules/s	Flux, Gg/yr	2008 CARB GHG inventory,[a] Gg/yr
Olinda Alpha	8 May	1.13	9.5	
	14 May	1.45	12.2	
	16 May	1.74	14.6	
	19 May	1.61	13.5	
	20 June	2.90	24.3	
	average[b]	**1.49 ± 0.35**	**12.5 ± 2.9**	**11.0**
Puente Hills	8 May	4.29	36.0	
	19 May	3.62	30.4	
	20 June	4.48	37.6	
	average[b]	**4.06 ± 1.18**	**34.0 ± 9.9**	**38.8**

[a] data from CARB [L. Hunsaker, personal communication, June 2011]

[b] weighted average, assuming a 50% uncertainty in the individual flux determinations [*Taylor*, 1997]

Table 4. Derived emissions in the South Coast Air Basin (in Gg/yr) for 2010 from each source sector used in linear analysis.

	Pipeline-quality dry NG/ local seeps	CH_4-dominant (landfills, dairies, etc.)	Local NG	LPG/propane	Evaporated gasoline	Mobile sources	CARB other	Summed source totals	Estimated SoCAB total[a]
CH_4	192 ± 54	182 ± 54	32 ± 7	---	---	4.9 ± 1.3	1.2 ± 0.3	411 ± 77	411[b] ± 37
ethane	5.9 ± 1.7	---	4.5 ± 1.0	0.05 ± 0.02	0.0 ± 0.0	0.6 ± 0.1	0.3 ± 0.1	11.4 ± 1.9	11.4[b] ± 1.6
propane	1.5 ± 0.4	---	9.9 ± 2.0	6.6 ± 2.9	0.006 ± 0.001	0.1 ± 0.0	1.6 ± 0.4	19.8 ± 3.6	19.8 ± 2.7
n-butane	0.3 ± 0.1	---	5.9 ± 1.2	0.02 ± 0.01	0.5 ± 0.1	0.3 ± 0.1	1.4 ± 0.4	8.5 ± 1.3	8.3 ± 1.2
i-butane	0.3 ± 0.1	---	2.2 ± 0.5	0.13 ± 0.06	0.08 ± 0.02	0.04 ± 0.01	1.8 ± 0.5	4.6 ± 0.6	5.1 ± 0.7
n-pentane	0.07 ± 0.02	---	2.2 ± 0.5	---	2.6 ± 0.4	1.0 ± 0.1	0.3 ± 0.1	6.6 ± 0.6	6.5 ± 0.9
i-pentane	0.11 ± 0.03	---	2.4 ± 0.5	0.003 ± 0.001	7.6 ± 1.0	3.9 ± 0.5	0.03 ± 0.01	14.1 ± 1.2	14.1 ± 1.8

[a] includes measurement, ODR fit, and inventory uncertainty

[b] *Wennberg et al.* [2012] estimate emissions to the SoCAB of 440 ± 100 Gg CH_4/yr and 12.9 ± 0.9 Gg ethane/yr

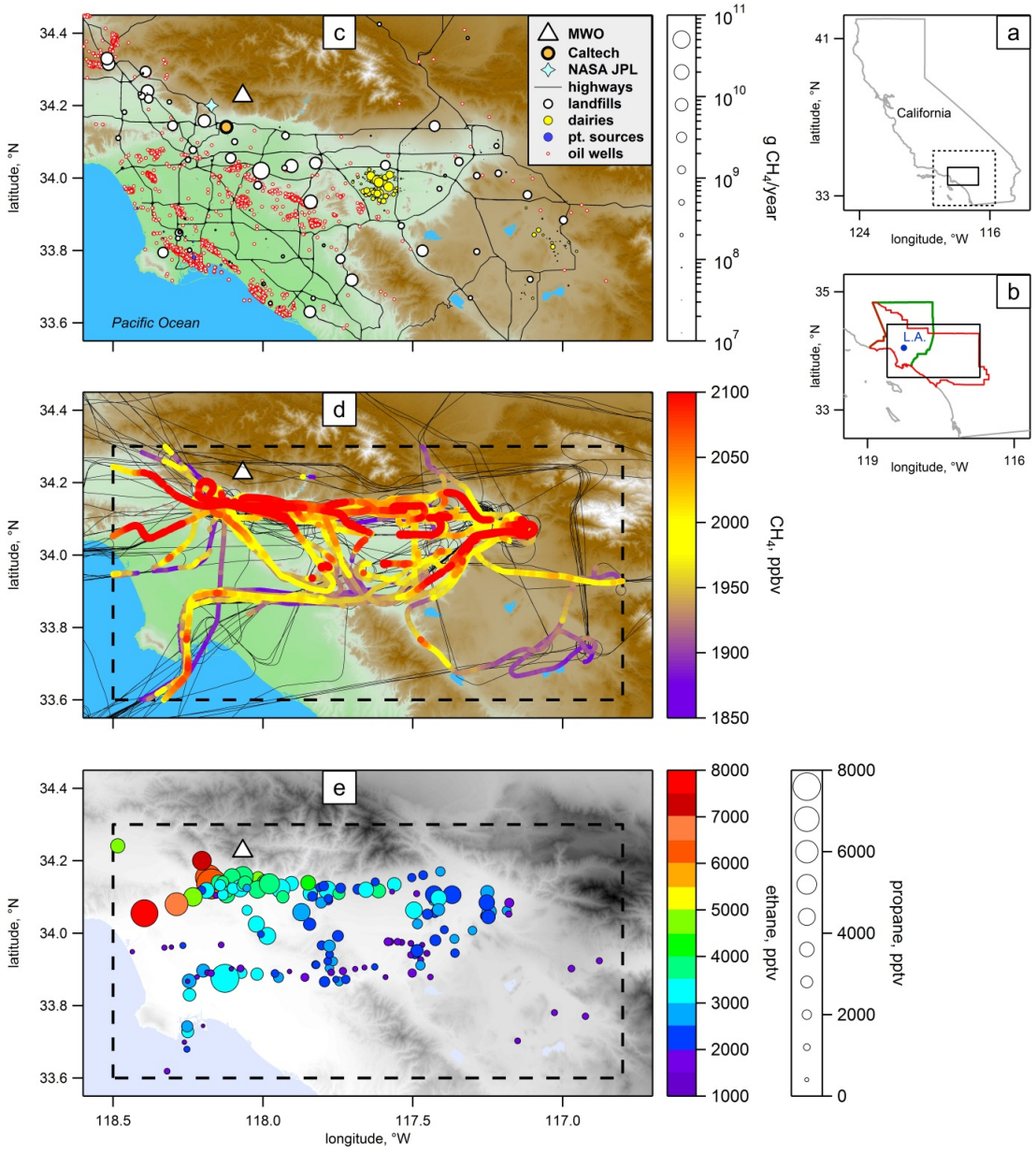

Figure 1. **a)** Map of California. The dashed box shows the inset for panel (b), the solid box shows the extent of the map boundaries for panels (c) – (e). **b)** Map of southern California showing the location of downtown L.A. (blue dot), the Los Angeles County boundary (green), the South Coast Air Basin boundary (red), and the extent of the map boundaries for panels (c) – (e) (black box). **c)** Map of the L.A. region showing known sources of CH_4 in the L.A. basin. The white triangle shows the location of the Mt. Wilson Observatory, where ground-based measurements were made by *Hsu et al.* [2010] and in this study. The light blue star shows the location of the Jet Propulsion Laboratory, where *Wunch et al.* [2009] made their measurements. The CalNex Pasadena ground site was located on the California Institute of Technology (Caltech) campus, located at the orange filled circle. Landfills (white circles) and CH_4 point sources (filled blue circles; negligibly small) are sized by emissions in the 2008 CARB greenhouse gas inventory. Dairies (filled yellow circles) are sized by the estimated emissions from the number of cows from *Salas et al.* [2008] multiplied by the 2009 CARB GHG inventory annual CH_4 emission per cow from enteric fermentation. **d)** Same map of the Los Angeles region as in (c), with flight tracks from 16 daytime flights of the NOAA P-3 (thin black lines). CH_4 measurements from the daytime boundary layer are color-coded atop these tracks according to the legend to the right. **e)** Locations of whole air samples in the L.A. basin, colored by ethane mixing ratio and sized by propane mixing ratio as indicated in the legends to the right.

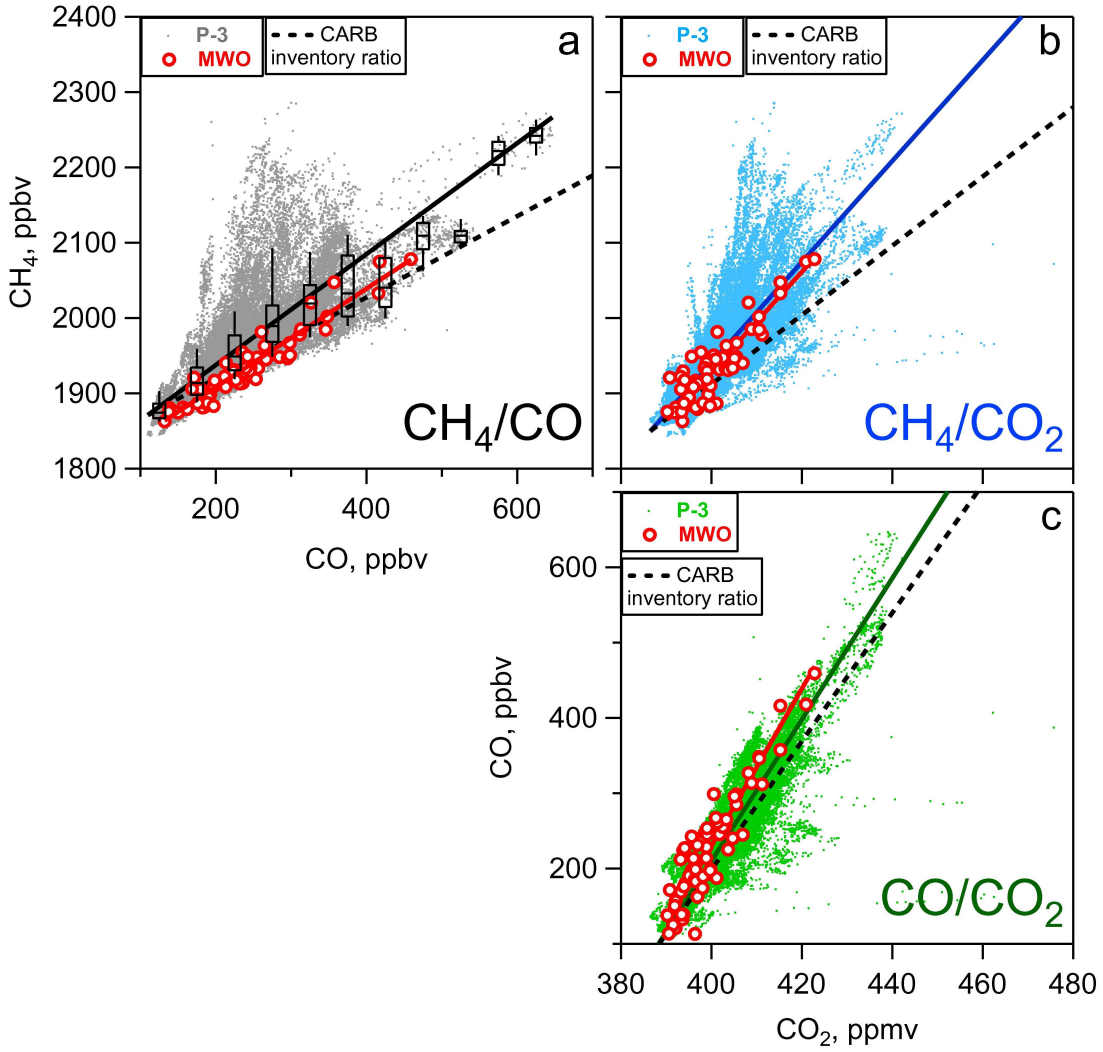

Figure 2. Scatter plots of CH_4, CO_2, and CO from all 1-second data points along flight track highlighted in Figure 1. Dots are from the NOAA P-3, while red circles are from NOAA GMD flask samples taken at the Mt. Wilson Observatory during CalNex. Weighted ODRs (solid lines) result in slopes of **(a)** 0.74 ± 0.04 and 0.68 ± 0.04 ppb CH_4/ppb CO; **(b)** 6.70 ± 0.01 and 6.60 ± 0.04 ppb CH_4/ppm CO_2; and **(c)** 9.4 ± 0.5 and 10.4 ± 0.5 ppb CO/ppm CO_2 from the NOAA P-3 and Mt. Wilson Observatory, respectively. The black dotted lines represent molar ratios of the CARB inventories listed in Table 2: CH_4:CO = 0.54, CH_4:CO_2 = 4.64 × 10^{-3}, and CO:CO_2 = 8.5 × 10^{-3}, where the background values used are the same as those determined from the fitted slopes. Also plotted in Figure 2a are boxes (25^{th}–75^{th} percentiles), whiskers (10^{th}–90^{th} percentiles), and the median (horizontal line) for distributions of CH_4 data calculated for 50 ppbv-wide bins from the NOAA P-3 CO data.

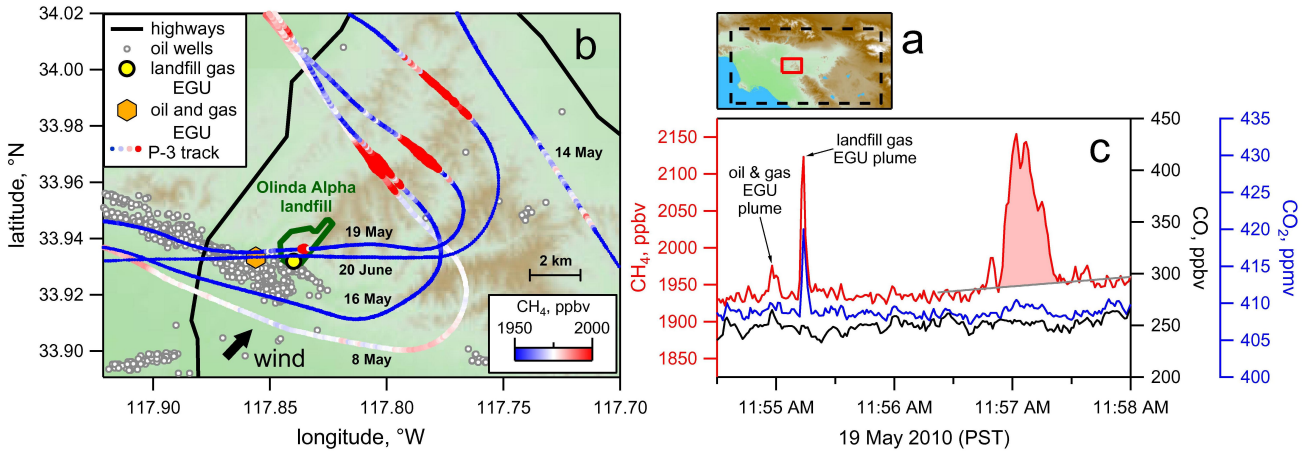

Figure 3. **a)** The map from Figure 1c–e shows the inset for part (b) in red. **b)** Five downwind transects, sized and colored by CH_4 mixing ratio, showing enhancements in CH_4 downwind of the Olinda Alpha landfill (green outline). Winds were from the southwest, except on 14 May, when they were from the west-southwest. **c)** Example of integration of the CH_4 plume from the 19 May flight. The filled pink area is integrated above the surrounding background (gray line). The upwind transect on this day passed downwind of two power plant (EGU) plumes.

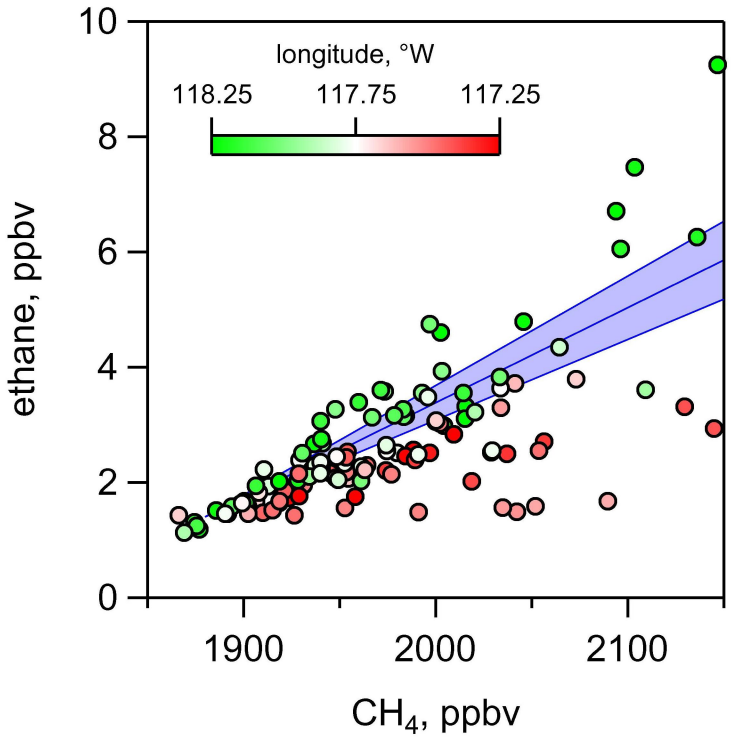

Figure 4. Scatter plot of ethane vs. CH_4 from the NOAA P-3 data in the L.A. basin. Data points are colored by longitude to show the different distributions of ethane to CH_4 in the eastern (red) and western (green) parts of the basin. The blue line represents the slope of 1.65 ± 0.25 % used by *Wennberg et al.* [2012] to represent the estimated ethane/CH_4 ratio of pipeline-quality dry natural gas from the Southern California Gas Company's pipelines.

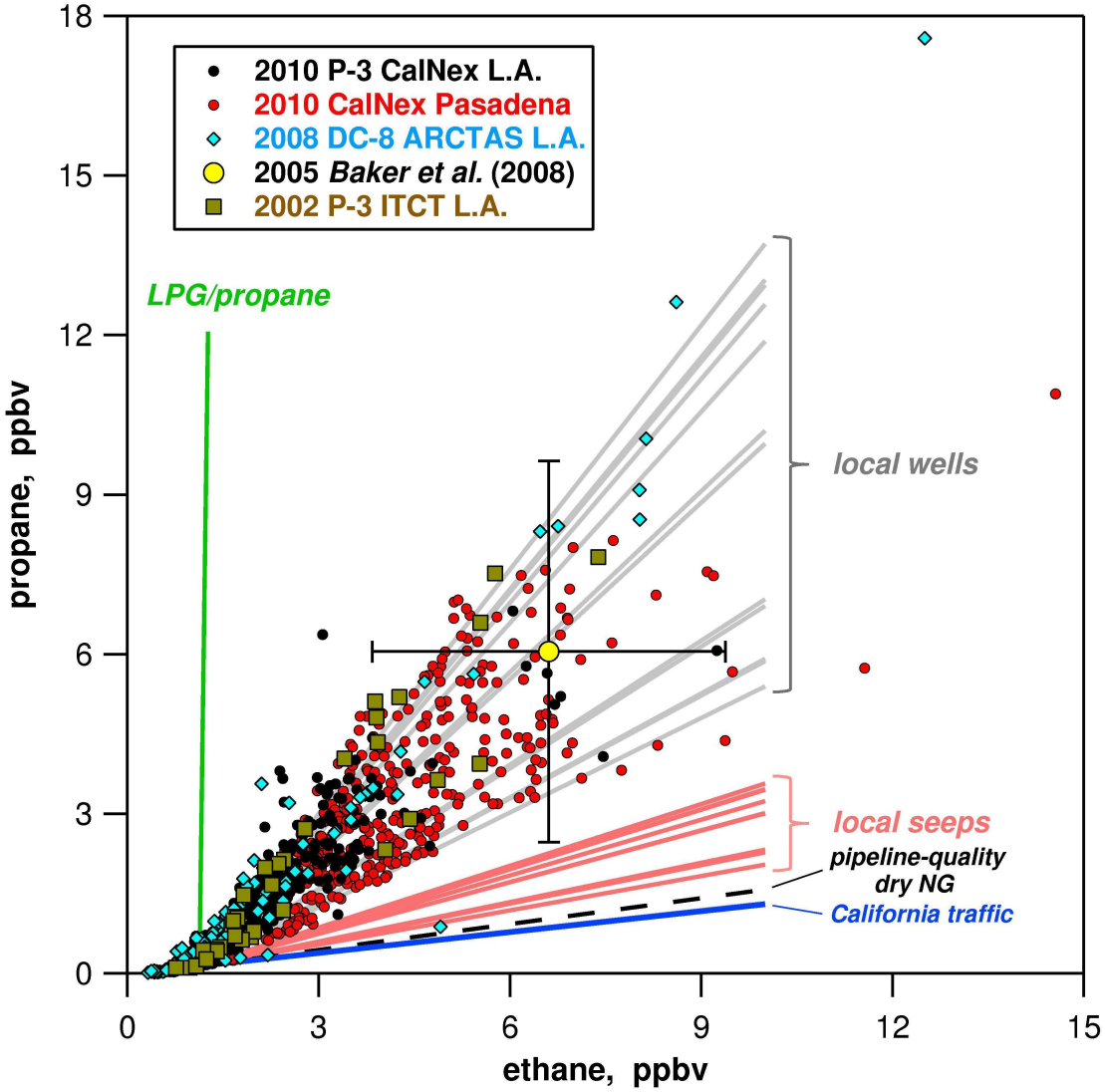

Figure 5. Correlation plot of propane vs. ethane from four Los Angeles datasets. Also plotted are composition ratios of local wells (gray lines) and local seeps (salmon lines) reported by *Jeffrey et al.* [1991], the composition ratio of pipeline-quality dry natural gas (black dashed line), the propane/ethane emission ratio from a San Francisco Bay-area tunnel study reported by *Kirchstetter et al.* [1996], and the average composition ratio of liquefied petroleum gas (LPG), or propane (green line).

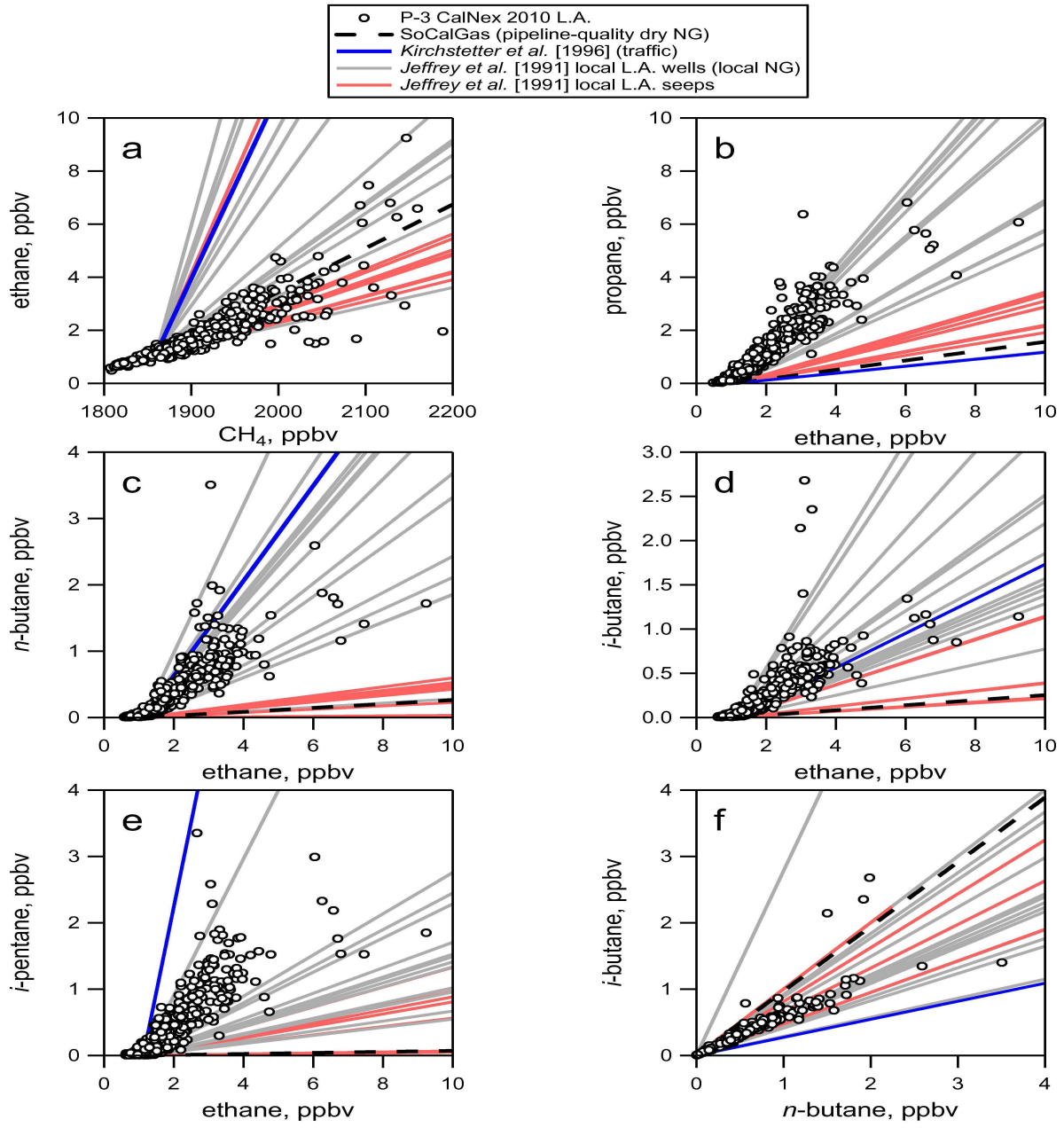

Figure 6. Plots of CH_4 and C_2–C_5 alkanes from the NOAA P-3 CalNex data set, selected for the SoCAB (black circles). Nighttime and high-altitude data are included. Also included for reference are the emission ratios of mobile sources from *Kirchstetter et al.* [1996] (blue line), composition ratios measured by *Jeffrey et al.* [1991] for local natural gas (gray lines) and local geologic seeps (salmon lines), and composition ratios from pipeline-quality dry natural gas (NG) delivered by SoCalGas (dashed black line). These ratios were plotted from daytime background levels.

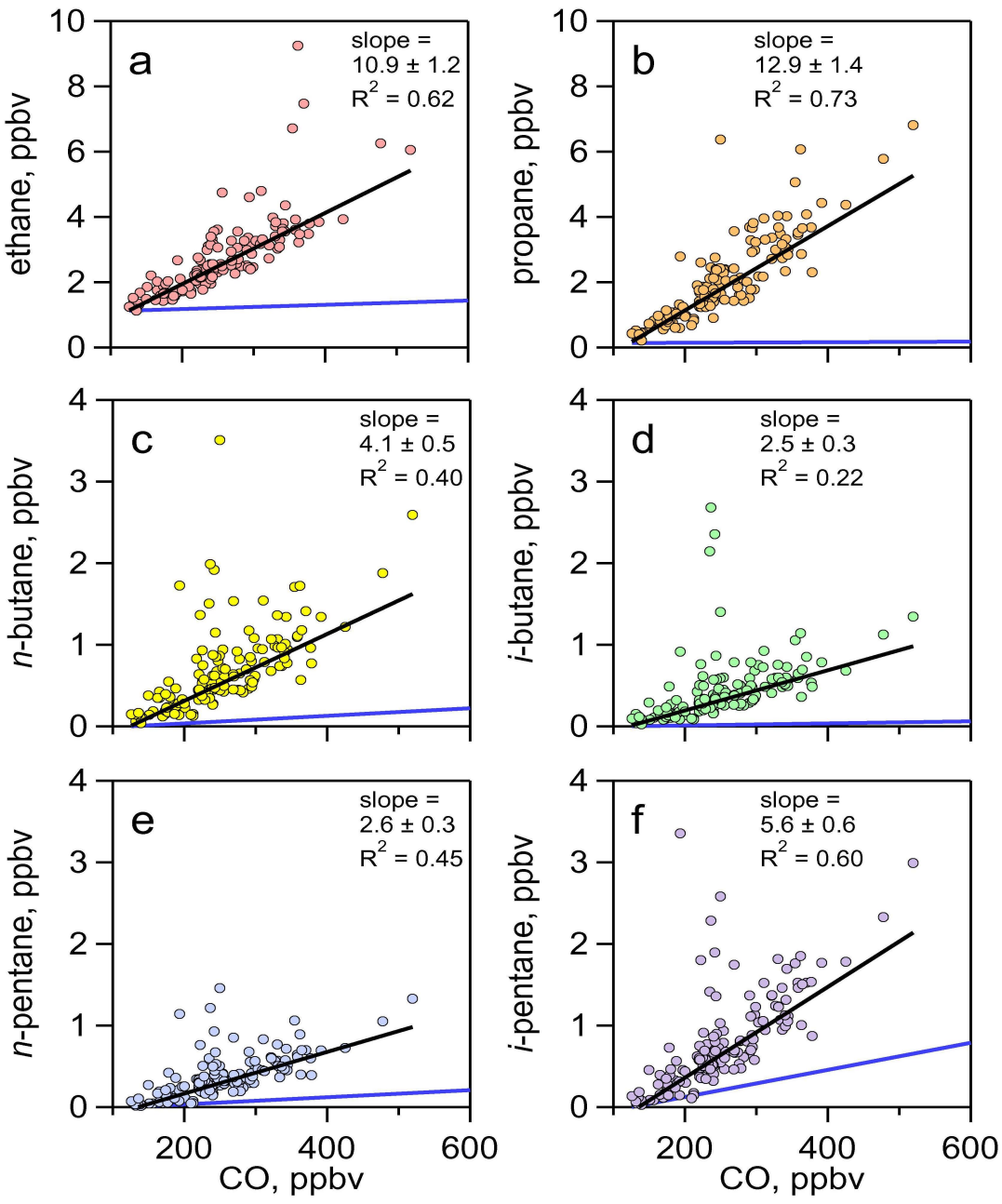

Figure 7. a–f) Daytime measurements of alkanes vs. CO from the NOAA P-3 in the L.A. basin during CalNex are plotted as filled circles. For comparison, the alkane/CO emission ratios from a San Francisco Bay-area tunnel study [*Kirchstetter et al.*, 1996] are plotted as a solid blue line, which extends to the edge of the right axis. The slope from a weighted ODR (given as ppt alkane/ppb CO), total slope uncertainty, and R^2 are given in each panel.

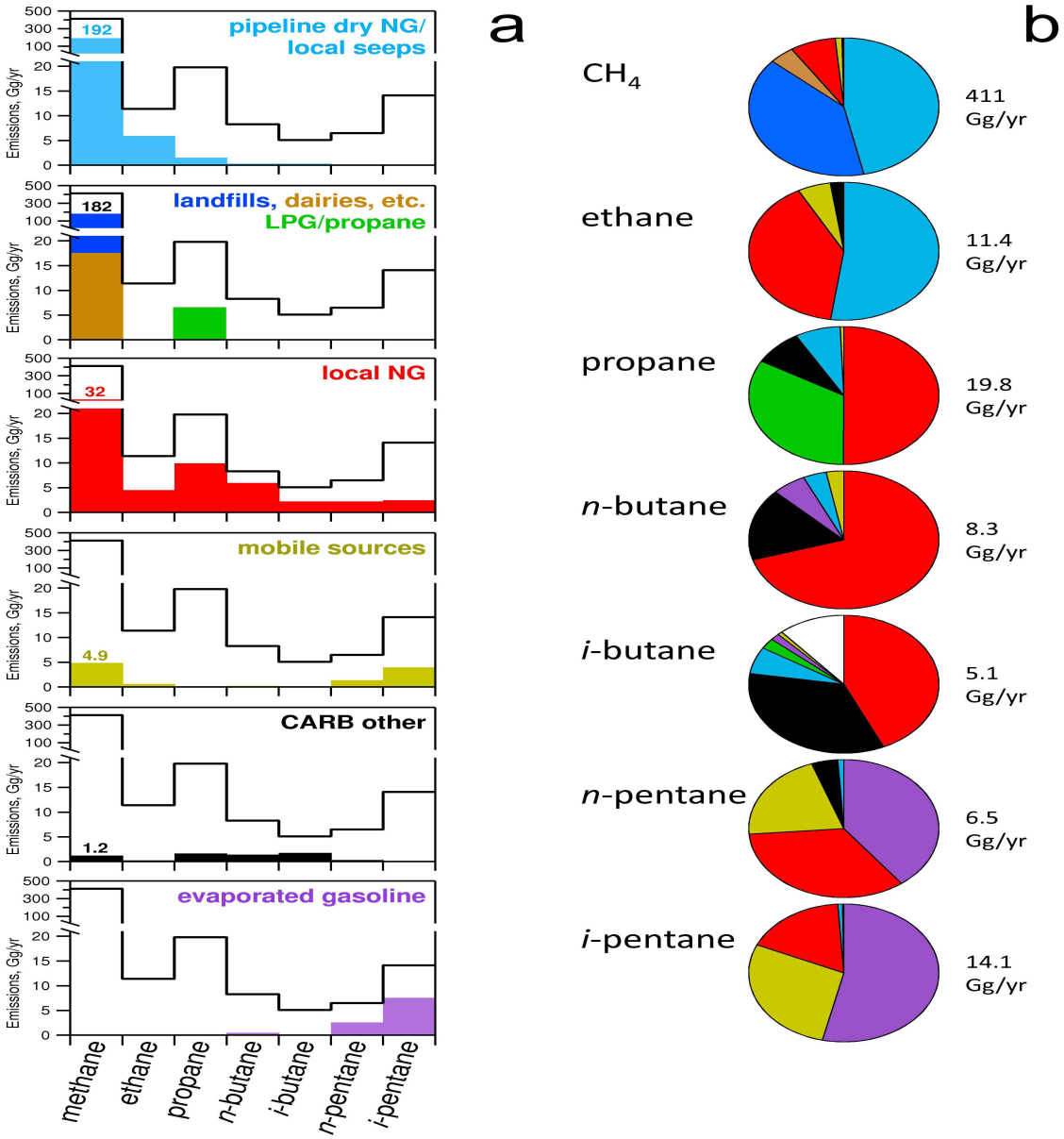

Figure 8. **a)** Results from a linear least squares solution to a combination of six sources and seven trace gas species in the SoCAB. The thick black line represents the estimated total annual emission to the SoCAB for seven hydrocarbons (CH_4 and C_2–C_5). The colored bars represent the fraction of the total contributed by each of the six source sectors used in the linear analysis. CH_4 emissions are written above the bar. **b)** Pie charts for the same data in (a) showing the relative contributions from each source for each of seven alkanes, colored as in part (a). The white region in the *i*-butane pie chart represents the 11% shortfall between our source attribution and our estimated emission to the SoCAB, though it is within the uncertainties of these two values. The total emission of the alkane to the SoCAB is given to the right of each pie chart.

Anthropogenic emissions of methane in the United States

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This study quantitatively estimates the spatial distribution of anthropogenic methane sources in the United States by combining comprehensive atmospheric methane observations, extensive spatial datasets, and a high-resolution atmospheric transport model. Results show that current inventories from the US Environmental Protection Agency (EPA) and the Emissions Database for Global Atmospheric Research underestimate methane emissions nationally by a factor of ∼1.5 and ∼1.7, respectively. Our study indicates that emissions due to ruminants and manure are up to twice the magnitude of existing inventories. In addition, the discrepancy in methane source estimates is particularly pronounced in the south-central United States, where we find total emissions are ∼2.7 times greater than in most inventories and account for 24 ± 3% of national emissions. The spatial patterns of our emission fluxes and observed methane–propane correlations indicate that fossil fuel extraction and refining are major contributors (45 ± 13%) in the south-central United States. This result suggests that regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR, the most comprehensive global methane inventory. These results cast doubt on the US EPA's recent decision to downscale its estimate of national natural gas emissions by 25–30%. Overall, we conclude that methane emissions associated with both the animal husbandry and fossil fuel industries have larger greenhouse gas impacts than indicated by existing inventories.

climate change policy | geostatistical inverse modeling

Methane (CH_4) is the second most important anthropogenic greenhouse gas, with approximately one third the total radiative forcing of carbon dioxide (1). CH_4 also enhances the formation of surface ozone in populated areas, and thus higher global concentrations of CH_4 may significantly increase ground-level ozone in the Northern Hemisphere (2). Furthermore, methane affects the ability of the atmosphere to oxidize other pollutants and plays a role in water formation within the stratosphere (3).

Atmospheric concentrations of CH_4 [∼1,800 parts per billion (ppb)] are currently much higher than preindustrial levels (∼680–715 ppb) (1, 4). The global atmospheric burden started to rise rapidly in the 18th century and paused in the 1990s. Methane levels began to increase again more recently, potentially from a combination of increased anthropogenic and/or tropical wetland emissions (5–7). Debate continues, however, over the causes behind these recent trends (7, 8).

Anthropogenic emissions account for 50–65% of the global CH_4 budget of ∼395–427 teragrams of carbon per year $(TgC{\cdot}y)^{-1}$ (526–569 Tg CH_4) (7, 9). The US Environmental Protection Agency (EPA) estimates the principal anthropogenic sources in the United States to be (in order of importance) (*i*) livestock (enteric fermentation and manure management), (*ii*) natural gas production and distribution, (*iii*) landfills, and (*iv*) coal mining (10). EPA assesses human-associated emissions in the United States in 2008 at 22.1 TgC, roughly 5% of global emissions (10).

The amount of anthropogenic CH_4 emissions in the US and attributions by sector and region are controversial (Fig. 1). Bottom-up inventories from US EPA and the Emissions Database for Global Atmospheric Research (EDGAR) give totals ranging from 19.6 to 30 $TgC{\cdot}y^{-1}$ (10, 11). The most recent EPA and EDGAR inventories report lower US anthropogenic emissions compared with previous versions (decreased by 10% and 35%, respectively) (10, 12); this change primarily reflects lower, revised emissions estimates from natural gas and coal production Fig. S1. However, recent analysis of CH_4 data from aircraft estimates a higher budget of 32.4 ± 4.5 $TgC{\cdot}y^{-1}$ for 2004 (13). Furthermore, atmospheric observations indicate higher emissions in natural gas production areas (14–16); a steady 20-y increase in the number of US wells and newly-adopted horizontal drilling techniques may have further increased emissions in these regions (17, 18).

These disparities among bottom-up and top-down studies suggest much greater uncertainty in emissions than typically reported. For example, EPA cites an uncertainty of only ±13% for the for United States (10). Independent assessments of bottom-up inventories give error ranges of 50–100% (19, 20), and

Significance

Successful regulation of greenhouse gas emissions requires knowledge of current methane emission sources. Existing state regulations in California and Massachusetts require ∼15% greenhouse gas emissions reductions from current levels by 2020. However, government estimates for total US methane emissions may be biased by 50%, and estimates of individual source sectors are even more uncertain. This study uses atmospheric methane observations to reduce this level of uncertainty. We find greenhouse gas emissions from agriculture and fossil fuel extraction and processing (i.e., oil and/or natural gas) are likely a factor of two or greater than cited in existing studies. Effective national and state greenhouse gas reduction strategies may be difficult to develop without appropriate estimates of methane emissions from these source sectors.

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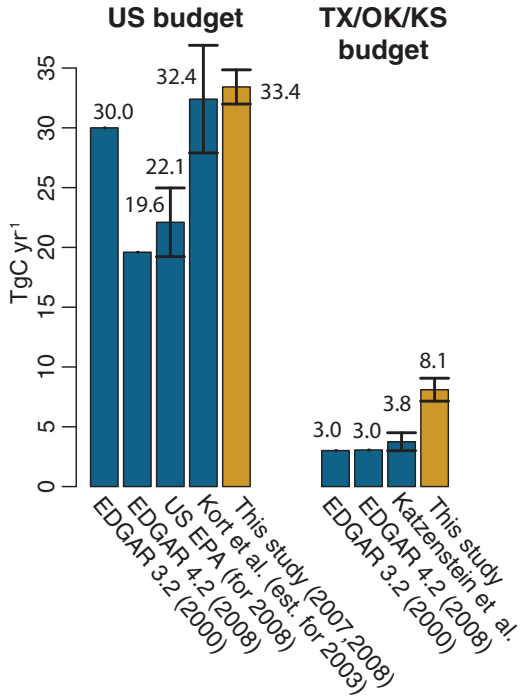

Fig. 1. US anthropogenic methane budgets from this study, from previous top-down estimates, and from existing emissions inventories. The south-central United States includes Texas, Oklahoma, and Kansas. US EPA estimates only national, not regional, emissions budgets. Furthermore, national budget estimates from EDGAR, EPA, and Kort et al. (13) include Alaska and Hawaii whereas this study does not.

values from Kort et al. are 47 ± 20% higher than EPA (13). Assessments of CH_4 sources to inform policy (e.g., regulating emissions or managing energy resources) require more accurate, verified estimates for the United States.

This study estimates anthropogenic CH_4 emissions over the United States for 2007 and 2008 using comprehensive CH_4 observations at the surface, on telecommunications towers, and from aircraft, combined with an atmospheric transport model and a geostatistical inverse modeling (GIM) framework. We use auxiliary spatial data (e.g., on population density and economic activity) and leverage concurrent measurements of alkanes to help attribute emissions to specific economic sectors. The work provides spatially resolved CH_4 emissions estimates and associated uncertainties, as well as information by source sector, both previously unavailable.

Model and Observation Framework

We use the Stochastic Time-Inverted Lagrangian Transport model (STILT) to calculate the transport of CH_4 from emission points at the ground to measurement locations in the atmosphere (21). STILT follows an ensemble of particles backward in time, starting from each observation site, using wind fields and turbulence modeled by the Weather Research and Forecasting (WRF) model (22). STILT derives an influence function ("footprint," units: ppb CH_4 per unit emission flux) linking upwind emissions to each measurement. Inputs of CH_4 from surface sources along the ensemble of back-trajectories are averaged to compute the CH_4 concentration for comparison with each observation.

We use observations for 2007 and 2008 from diverse locations and measurement platforms. The principal observations derive from daily flask samples on tall towers (4,984 total observations) and vertical profiles from aircraft (7,710 observations). Tower-based observations are collected as part of the National Oceanic and Atmospheric (NOAA)/Department of Energy (DOE) cooperative air sampling network, and aircraft-based data are obtained from regular NOAA flights (23), regular DOE flights (24), and from the Stratosphere-Troposphere Analyses of Regional Transport 2008 (START08) aircraft campaign (25); all data are publicly available from NOAA and DOE. These observations are displayed in Fig. 2 and discussed further in the *SI Text* (e.g., Fig. S2). We use a GIM framework (26, 27) to analyze the footprints for each of the 12,694 observations, and these footprints vary by site and with wind conditions. In aggregate, the footprints provide spatially resolved coverage of most of the continental United States, except the southeast coastal region (Fig. S3).

The GIM framework, using footprints and concentration measurements, optimizes CH_4 sources separately for each month of 2007 and 2008 on a 1° × 1° latitude–longitude grid for the United States. The contributions of fluxes from natural wetlands are modeled first and subtracted from the observed CH_4 (2.0 $TgC{\cdot}y^{-1}$ for the continental United States); these fluxes are much smaller than anthropogenic sources in the United States and thus would be difficult to independently constrain from atmospheric data (*SI Text*).

The GIM framework represents the flux distribution for each month using a deterministic spatial model plus a stochastic spatially correlated residual, both estimated from the atmospheric observations. The deterministic component is given by a weighted linear combination of spatial activity data from the EDGAR 4.2 inventory; these datasets include any economic or demographic data that may predict the distribution of CH_4 emissions (e.g., gas production, human and ruminant population densities, etc.). Both the selection of the activity datasets to be retained in the model and the associated weights (emission factors) are optimized to best match observed CH_4 concentrations. Initially, seven activity datasets are included from EDGAR 4.2, (*i*) population, (*ii*) electricity production from power plants, (*iii*) ruminant population count, (*iv*) oil and conventional gas production, (*v*) oil refinery production, (*vi*) rice production, and (*vii*) coal production.

We select the minimum number of datasets with the greatest predictive ability using the Bayesian Information Criterion (BIC) (*SI Text*) (28). BIC numerically scores all combinations of available datasets based on how well they improve goodness of fit and applies a penalty that increases with the number of datasets retained.

The stochastic component represents sources that do not fit the spatial patterns of the activity data (Fig. S4). GIM uses

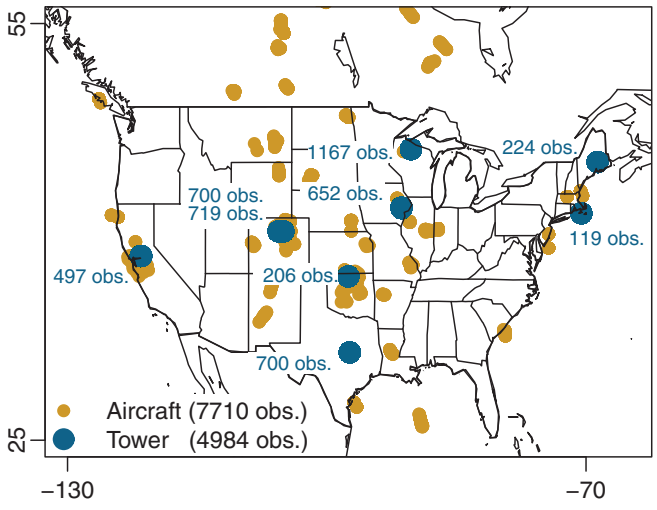

Fig. 2. CH_4 concentration measurements from 2007 and 2008 and the number of observations associated with each measurement type. Blue text lists the number of observations associated with each stationary tower measurement site.

a covariance function to describe the spatial and temporal correlation of the stochastic component and optimizes its spatial and temporal distribution simultaneously with the optimization of the activity datasets in the deterministic component (*SI Text*, Fig. S5) (26–28). Because of the stochastic component, the final emissions estimate can have a different spatial and temporal distribution from any combination of the activity data.

If the observation network is sensitive to a broad array of different source sectors and/or if the spatial activity maps are effective at explaining those sources, many activity datasets will be included in the deterministic model. If the deterministic model explains the observations well, the magnitude of CH_4 emissions in the stochastic component will be small, the assignment to specific sectors will be unambiguous, and uncertainties in the emissions estimates will be small. This result is not the case here, as discussed below (see *Results*).

A number of previous studies used top-down methods to constrain anthropogenic CH_4 sources from global (29–33) to regional (13–15, 34–38) scales over North America. Most regional studies adopted one of three approaches: use a simple box model to estimate an overall CH_4 budget (14), estimate a budget using the relative ratios of different gases (15, 37–39), or estimate scaling factors for inventories by region or source type (13, 34–36). The first two methods do not usually give explicit information about geographic distribution. The last approach provides information about the geographic distribution of sources, but results hinge on the spatial accuracy of the underlying regional or sectoral emissions inventories (40).

Here, we are able to provide more insight into the spatial distribution of emissions; like the scaling factor method above, we leverage spatial information about source sectors from an existing inventory, but in addition we estimate the distribution of emissions where the inventory is deficient. We further bolster attribution of regional emissions from the energy industry using the observed correlation of CH_4 and propane, a gas not produced by biogenic processes like livestock and landfills.

Results

Spatial Distribution of CH_4 Emissions. Fig. 3 displays the result of the 2-y mean of the monthly CH_4 inversions and differences from the EDGAR 4.2 inventory. We find emissions for the United States that are a factor of 1.7 larger than the EDGAR inventory. The optimized emissions estimated by this study bring the model closer in line with the observations (Fig. 4, Figs. S6 and S7). Posterior emissions fit the CH_4 observations [$R^2 = 0.64$, root mean square error (RMSE) = 31 ppb] much better than EDGAR v4.2 ($R^2 = 0.23$, RMSE = 49 ppb). Evidently, the spatial distribution of EDGAR sources is inconsistent with emissions patterns implied by the CH_4 measurements and associated footprints.

Several diagnostic measures preclude the possibility of major systematic errors in WRF–STILT. First, excellent agreement between the model and measured vertical profiles from aircraft implies little bias in modeled vertical air mixing (e.g., boundary-layer heights) (Fig. 4). Second, the monthly posterior emissions estimated by the inversion lack statistically significant seasonality (Fig. S8). This result implies that seasonally varying weather patterns do not produce detectable biases in WRF–STILT. *SI Text* discusses possible model errors and biases in greater detail.

CH_4 observations are sparse over parts of the southern and central East Coast and in the Pacific Northwest. Emissions estimates for these regions therefore rely more strongly on the deterministic component of the flux model, with weights constrained primarily by observations elsewhere. Therefore, emissions in these areas, including from coal mining, are poorly constrained (*SI Text*).

Contribution of Different Source Sectors. Only two spatial activity datasets from EDGAR 4.2 are selected through the BIC as meaningful predictors of CH_4 observations over the United States: population densities of humans and of ruminants (Table S1). Some sectors are eliminated by the BIC because emissions are situated far from observation sites (e.g., coal mining in West Virginia or Pennsylvania), making available CH_4 data insensitive to these predictors. Other sectors may strongly affect observed concentrations but are not selected, indicating that the spatial datasets from EDGAR are poor predictors for the distribution of observed concentrations (e.g., oil and natural gas extraction and oil refining). Sources from these sectors appear in the stochastic component of the GIM (*SI Text*).

The results imply that existing inventories underestimate emissions from two key sectors: ruminants and fossil fuel extraction and/or processing, discussed in the remainder of this section.

We use the optimized ruminant activity dataset to estimate the magnitude of emissions with spatial patterns similar to animal husbandry and manure. Our corresponding US budget of 12.7 ± 5.0 $TgC \cdot y^{-1}$ is nearly twice that of EDGAR and EPA (6.7 and 7.0, respectively). The total posterior emissions estimate over the northern plains, a region with high ruminant density but little fossil fuel extraction, further supports the ruminant estimate (Nebraska, Iowa, Wisconsin, Minnesota, and South Dakota). Our total budget for this region of 3.4 ± 0.7 compares with 1.5 $TgC \cdot y^{-1}$ in EDGAR. Ruminants and agriculture may also be

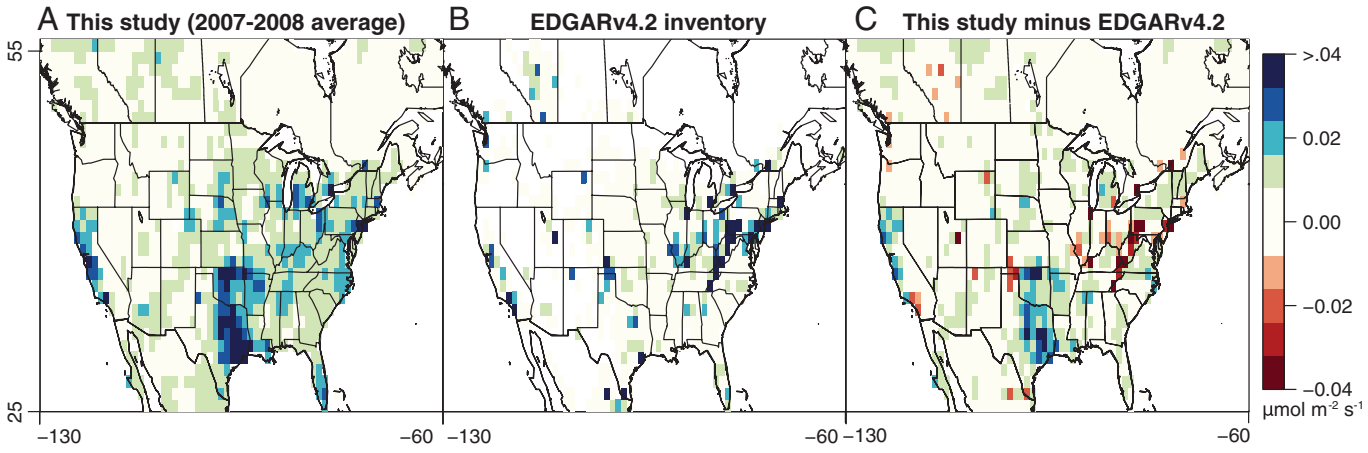

Fig. 3. The 2-y averaged CH_4 emissions estimated in this study (*A*) compared against the commonly used EDGAR 4.2 inventory (*B* and *C*). Emissions estimated in this study are greater than in EDGAR 4.2, especially near Texas and California.

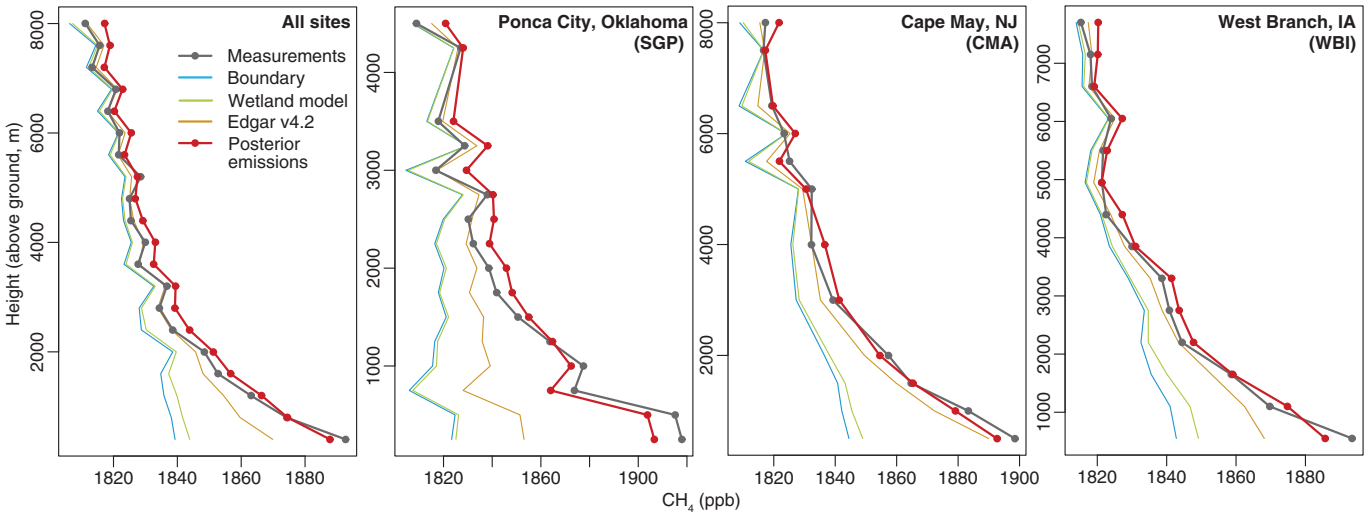

Fig. 4. A model–measurement comparison at several regular NOAA/DOE aircraft monitoring sites (averaged over 2007–2008). Plots include the measurements; the modeled boundary condition; the summed boundary condition and wetland contribution (from the Kaplan model); and the summed boundary, wetland, and anthropogenic contributions (from EDGAR v4.2 and the posterior emissions estimate).

partially responsible for high emissions over California (41). EDGAR activity datasets are poor over California (42), but several recent studies (34, 36–38, 41) have provided detailed top-down emissions estimates for the state using datasets from state agencies.

Existing inventories also greatly underestimate CH_4 sources from the south-central United States (Fig. 3). We find the total CH_4 source from Texas, Oklahoma, and Kansas to be 8.1 ± 0.96 $TgC{\cdot}y^{-1}$, a factor of 2.7 higher than the EDGAR inventory. These three states alone constitute ∼24 ± 3% of the total US anthropogenic CH_4 budget or 3.7% of net US greenhouse gas emissions [in CO_2 equivalents (10)].

Texas and Oklahoma were among the top five natural gas producing states in the country in 2007 (18), and aircraft observations of alkanes indicate that the natural gas and/or oil industries play a significant role in regional CH_4 emissions. Concentrations of propane (C_3H_8), a tracer of fossil hydrocarbons (43), are strongly correlated with CH_4 at NOAA/DOE aircraft monitoring locations over Texas and Oklahoma ($R^2 = 0.72$) (Fig. 5). Correlations are much weaker at other locations in North America ($R^2 = 0.11$ to 0.64).

We can obtain an approximate CH_4 budget for fossil-fuel extraction in the region by subtracting the optimized contributions associated with ruminants and population from the total emissions. The residual (Fig. S4*C*) represents sources that have spatial patterns not correlated with either human or ruminant density in EDGAR. Our budget sums to 3.7 ± 2.0 $TgC{\cdot}y^{-1}$, a factor of 4.9 ± 2.6 larger than oil and gas emissions in EDGAR v4.2 (0.75 $TgC{\cdot}y^{-1}$) and a factor of 6.7 ± 3.6 greater than EDGAR sources from solid waste facilities (0.55 $TgC{\cdot}y^{-1}$), the two major sources that may not be accounted for in the deterministic component. The population component likely captures a portion of the solid waste sources so this residual methane budget more likely represents natural gas and oil emissions than landfills. *SI Text* discusses in detail the uncertainties in this sector-based emissions estimate. We currently do not have the detailed, accurate, and spatially resolved activity data (fossil fuel extraction and processing, ruminants, solid waste) that would provide more accurate sectorial attribution.

Katzenstein et al. (2003) (14) were the first to report large regional emissions of CH_4 from Texas, Oklahoma, and Kansas; they cover an earlier time period (1999–2002) than this study. They used a box model and 261 near-ground CH_4 measurements taken over 6 d to estimate a total Texas–Oklahoma–Kansas CH_4 budget (from all sectors) of 3.8 ± 0.75 $TgC{\cdot}y^{-1}$. We revise their

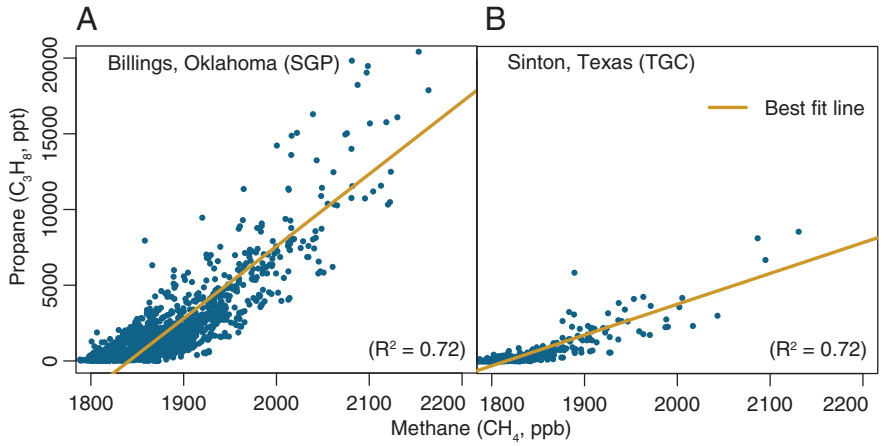

Fig. 5. Correlations between propane and CH_4 at NOAA/DOE aircraft observation sites in Oklahoma (*A*) and Texas (*B*) over 2007–2012. Correlations are higher in these locations than at any other North American sites, indicating large contributions of fossil fuel extraction and processing to CH_4 emitted in this region.

estimate upward by a factor of two based on the inverse model and many more measurements from different platforms over two full years of data. *SI Text* further compares the CH_4 estimate in Katzenstein et al. and in this study.

Discussion and Summary

This study combines comprehensive atmospheric data, diverse datasets from the EDGAR inventory, and an inverse modeling framework to derive spatially resolved CH_4 emissions and information on key source sectors. We estimate a mean annual US anthropogenic CH_4 budget for 2007 and 2008 of 33.4 ± 1.4 $TgC \cdot y^{-1}$ or ∼7–8% of the total global CH_4 source. This estimate is a factor of 1.5 and 1.7 larger than EPA and EDGAR v4.2, respectively. CH_4 emissions from Texas, Oklahoma, and Kansas alone account for 24% of US methane emissions, or 3.7% of the total US greenhouse gas budget.

The results indicate that drilling, processing, and refining activities over the south-central United States have emissions as much as 4.9 ± 2.6 times larger than EDGAR, and livestock operations across the US have emissions approximately twice that of recent inventories. The US EPA recently decreased its CH_4 emission factors for fossil fuel extraction and processing by 25–30% (for 1990–2011) (10), but we find that CH_4 data from across North America instead indicate the need for a larger adjustment of the opposite sign.

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