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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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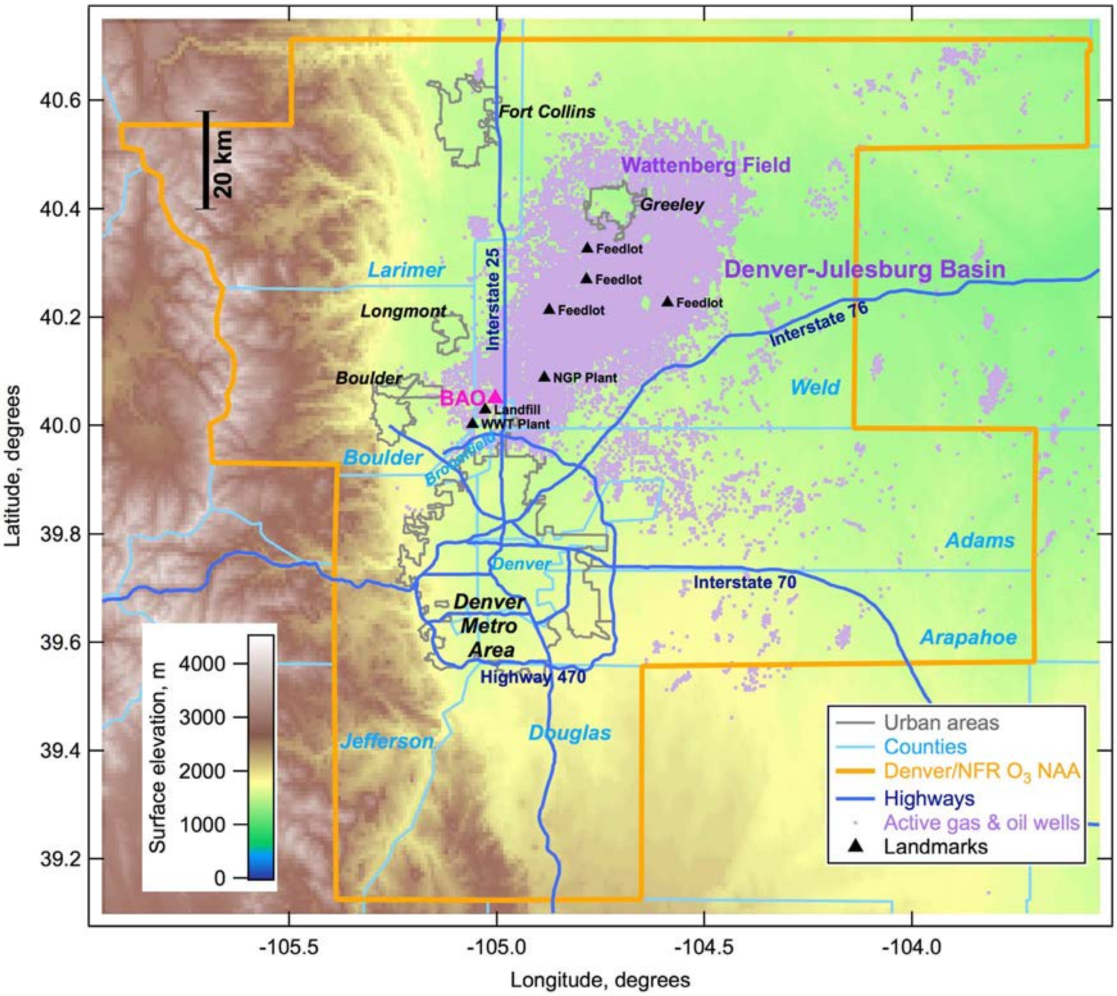

Figure 1. Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, 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

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[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

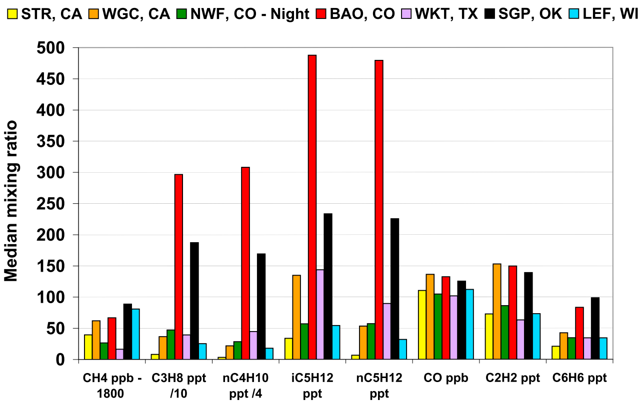

Figure 2. Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June–August (2007–2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly downslope winds. Notice the different 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.

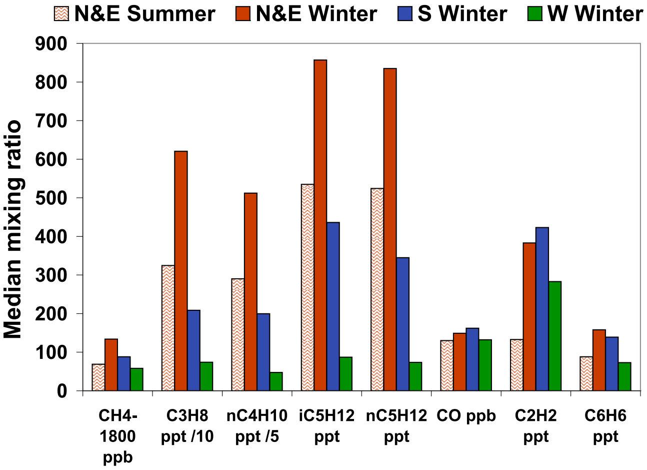

Figure 3. Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-m level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean 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.

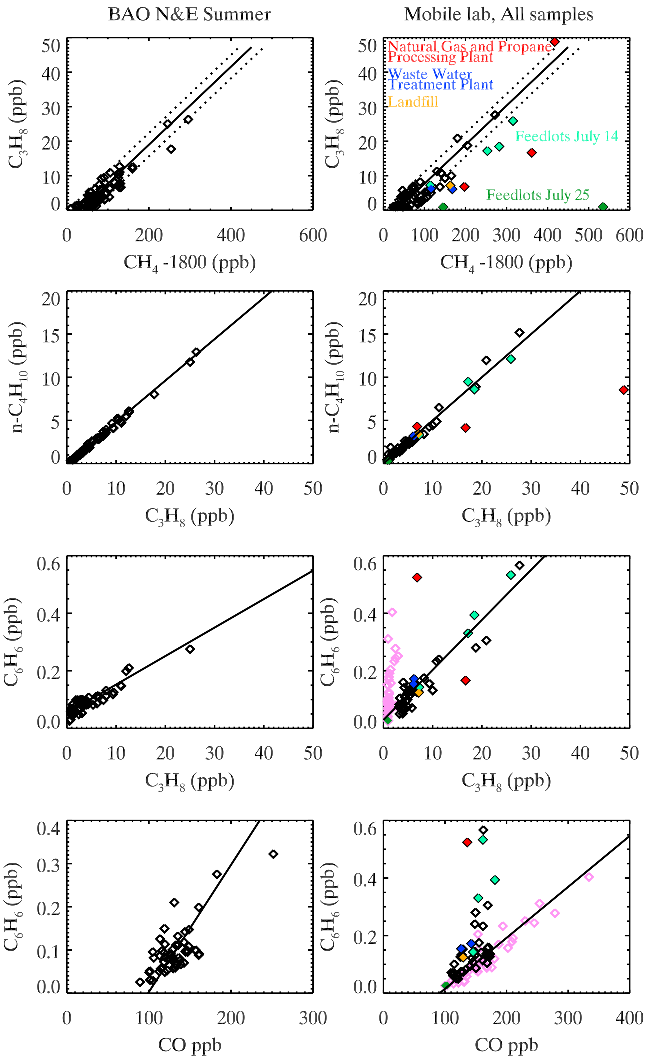

Figure 4. Correlation plots for various species measured in the (left) BAO summertime NE wind sector flask samples and (right) summer 2008 Mobile Lab samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 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 ($C_{3\text{–}5}$/CO and $C_{3\text{–}5}/C_2H_2$: $r^2 < 0.3$ for 50 summer samples; $C_{3\text{–}5}$/CO: $r^2 < 0.4$ and $C_{3\text{–}5}/C_2H_2$: $r^2 \sim 0.6$ 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														
Season		Summer			Winter			BAO South Winter			BAO West Winter			Mobile Lab Summer		
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.

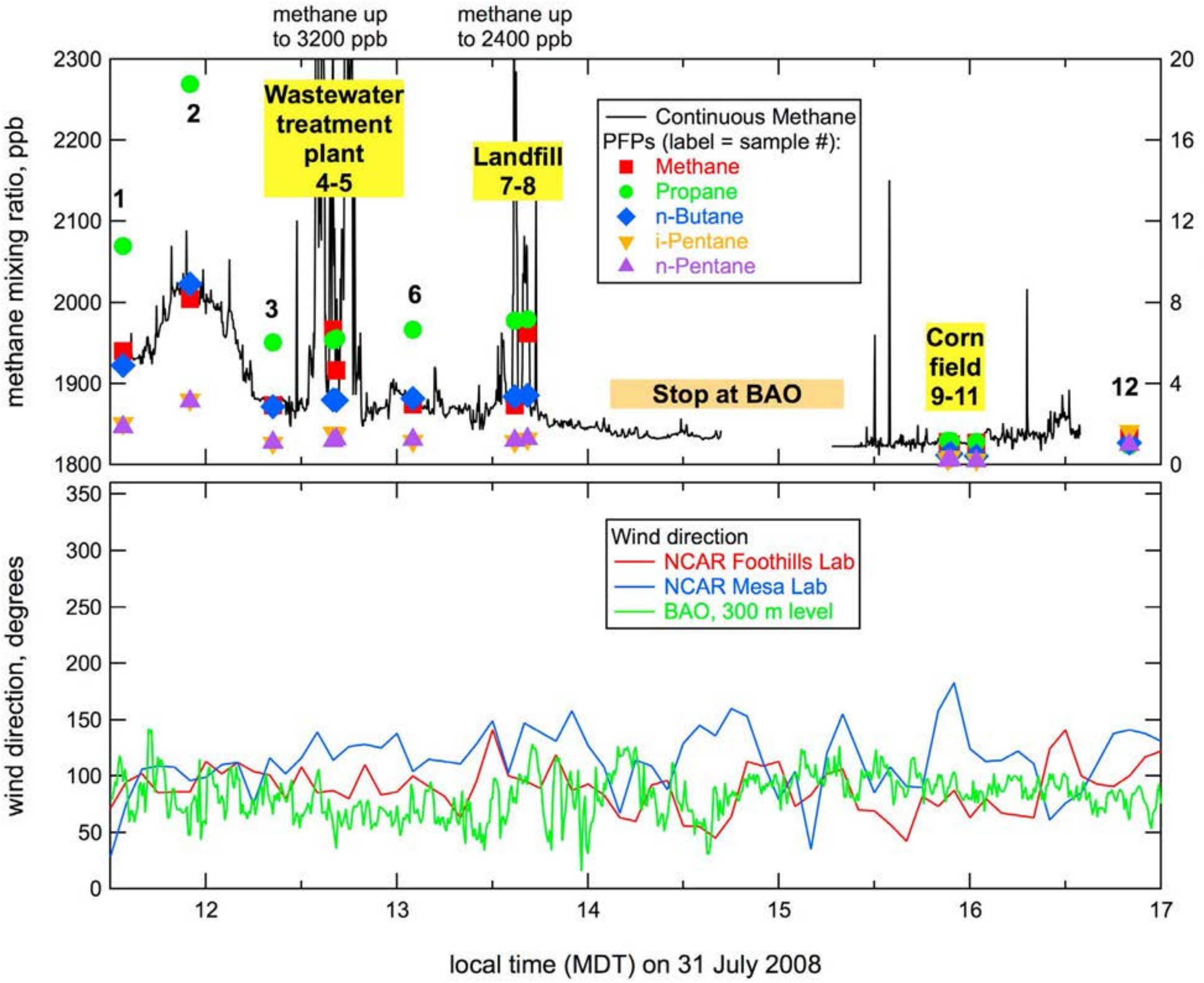

Figure 5. (top) Time series of the continuous methane measurements from Mobile Lab Survey 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in 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 ± 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-

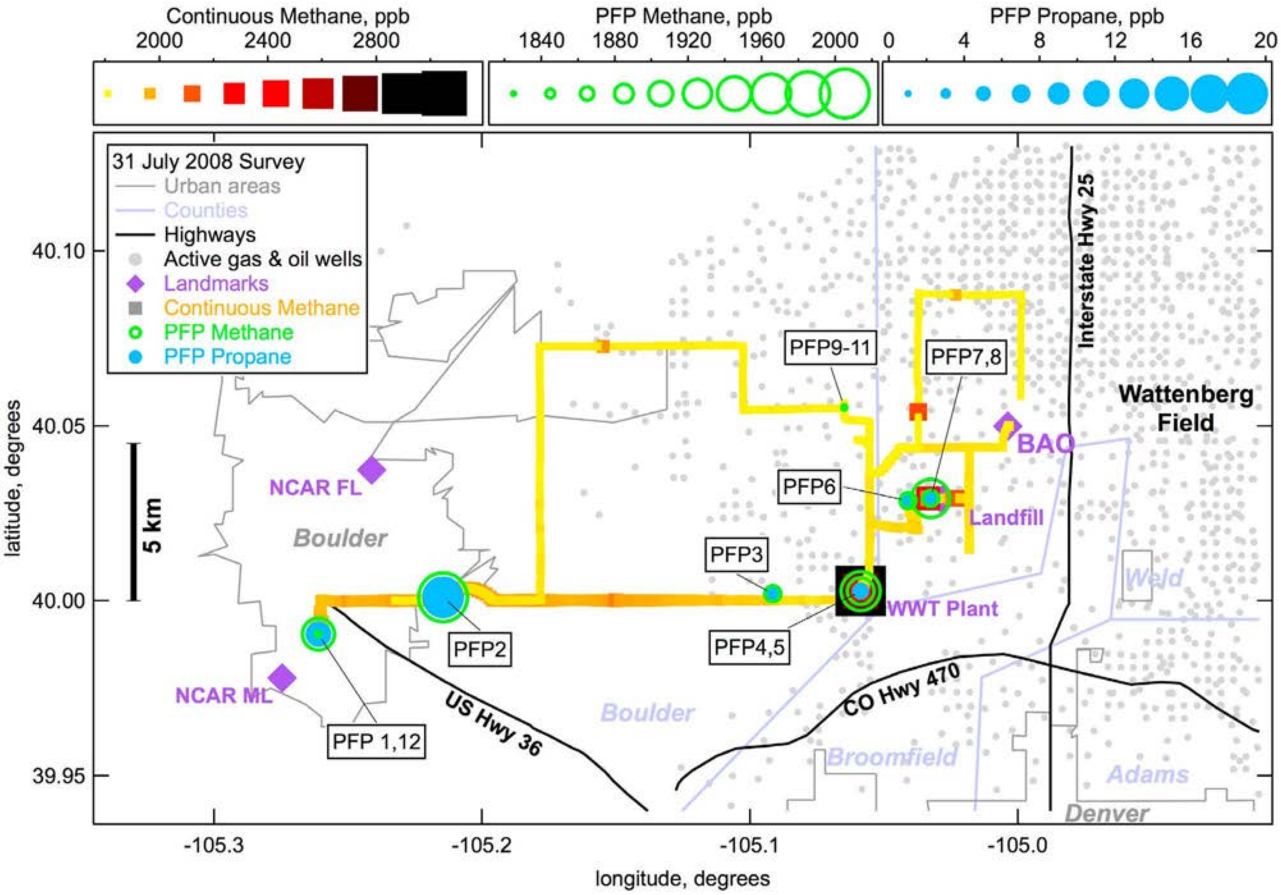

Figure 6. Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey 9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (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.

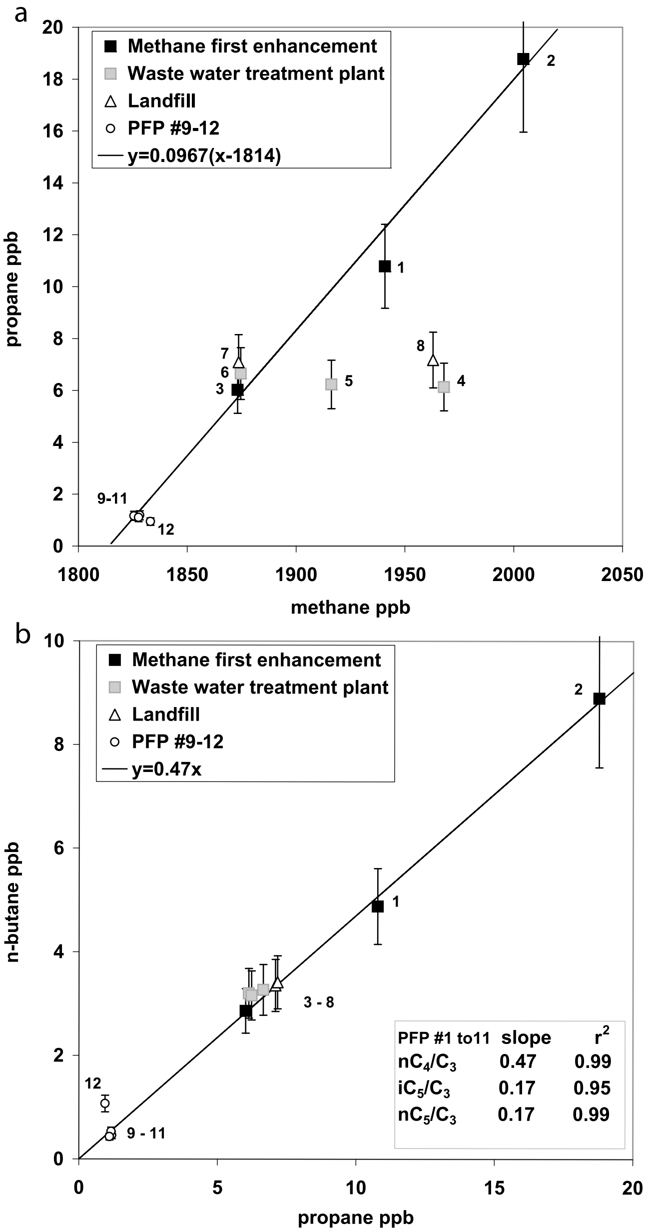

Figure 7. (a) Propane versus methane mixing ratios for air samples collected during Survey 9 on July 31, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 7a shows the correlation line for samples not impacted by local sources of methane (all flasks 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 ± 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 ± 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.

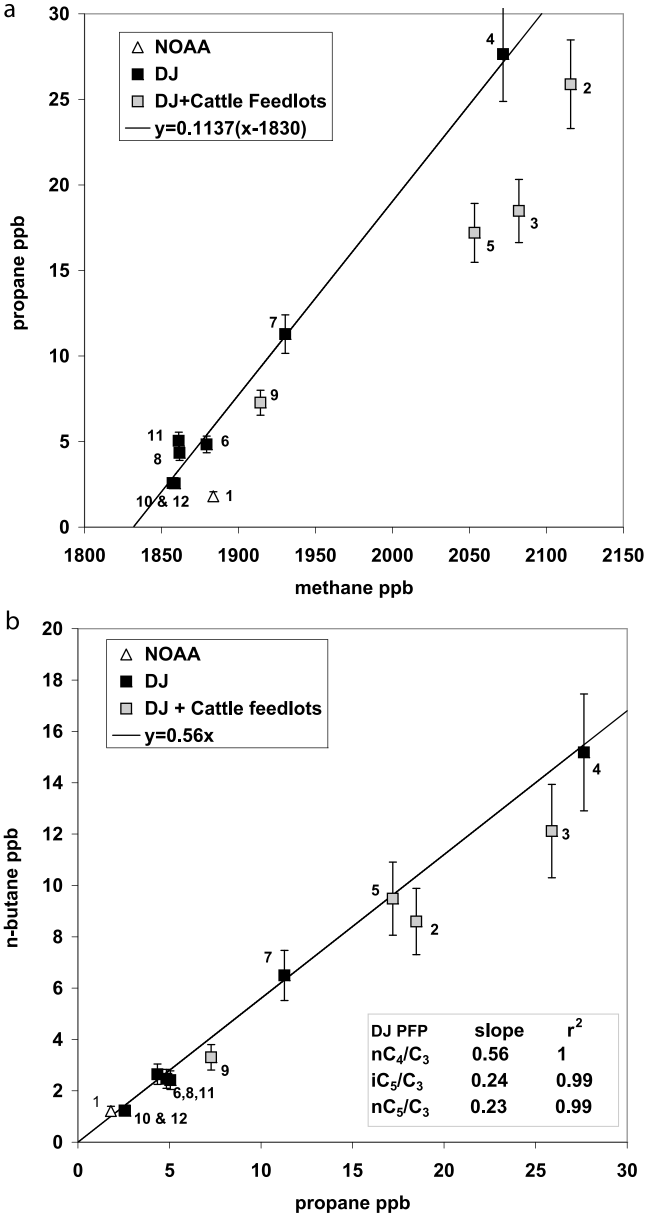

Figure 8. (a) Propane versus methane mixing ratios for air samples collected during Survey 6 on July 14, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 8a shows the correlation line for samples not impacted by local sources of methane (all flasks 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 ($\sim$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,

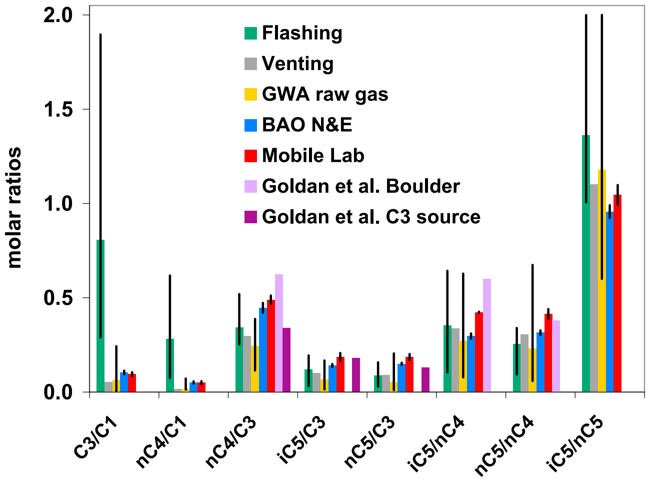

Figure 9. Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June–July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (gray) sources used by *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 $(y_m, y_p)_{\mathrm{tank}=1,16}$, 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)

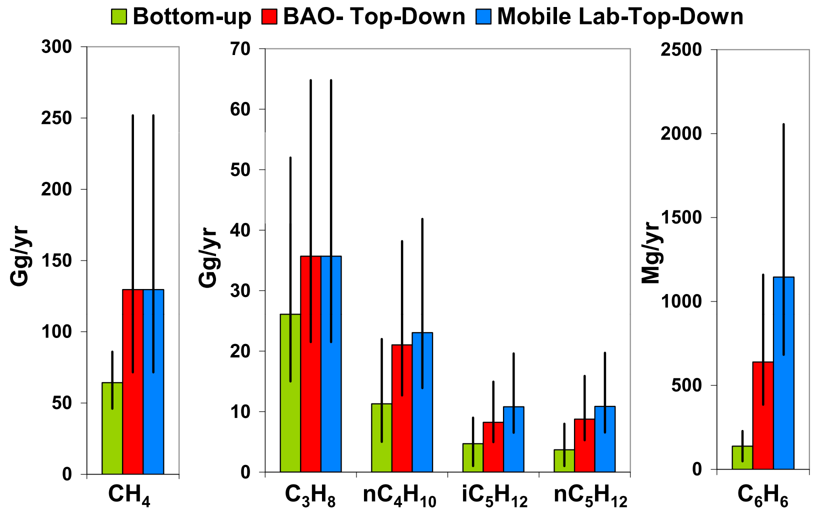

Figure 10. Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios 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.

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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.

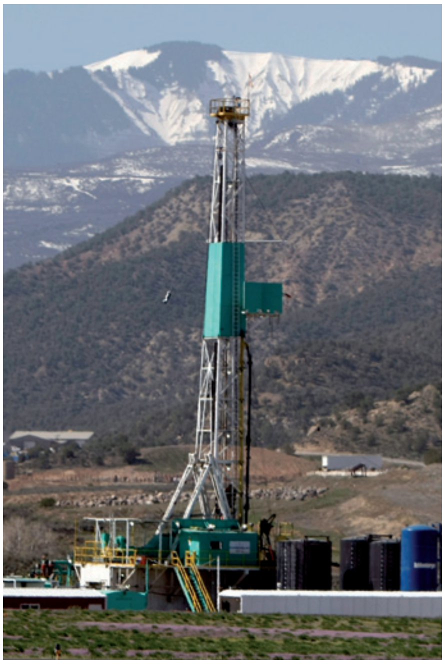
The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study[1] suggesting that up to 4% of the methane produced at a field near Denver was escaping into the 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.



L DAVID ZALUBOWSKI/AP

Natural-gas wells such as this one in Colorado are increasingly important to the US energy supply.

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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3. Pétron, G. *et al. J. Geophys. Res.* (in the press).
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Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources

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Abstract

Background: Technological advances (e.g. directional drilling, hydraulic fracturing), have led to increases in unconventional natural gas development (NGD), raising questions about health impacts.

Objectives: We estimated health risks for exposures to air emissions from a NGD project in Garfield County, Colorado with the objective of supporting risk prevention recommendations in a health impact assessment (HIA).

Methods: We used EPA guidance to estimate chronic and subchronic non-cancer hazard indices and cancer risks from exposure to hydrocarbons for two populations: (1) residents living > ½ mile from wells and (2) residents living ≤ ½ mile from wells.

Results: Residents living ≤ ½ mile from wells are at greater risk for health effects from NGD than are residents living > ½ mile from wells. Subchronic exposures to air pollutants during well completion activities present the greatest potential for health effects. The subchronic non-cancer hazard index (HI) of 5 for residents ≤ ½ mile from wells was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons. Chronic HIs were 1 and 0.4. for residents ≤ ½ mile from wells and > ½ mile from wells, respectively. Cumulative cancer risks were 10 in a million and 6 in a million for residents living ≤ ½ mile and > ½ mile from wells, respectively, with benzene as the major contributor to the risk.

Conclusions: Risk assessment can be used in HIAs to direct health risk prevention strategies. Risk management approaches should focus on reducing exposures to emissions during well completions. These preliminary results indicate that health effects resulting from air emissions during unconventional NGD warrant further study. Prospective studies should focus on health effects associated with air pollution.

Key Words: natural gas development; risk assessment; air pollution; hydrocarbon emissions

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The authors declare they have no competing financial interests.

Abbreviations[1]

1.0 Introduction

The United States (US) holds large reserves of unconventional natural gas resources in coalbeds, shale, and tight sands. Technological advances, such as directional drilling and hydraulic fracturing, have led to a rapid increase in the development of these resources. For example, shale gas production had an average annual growth rate of 48 percent over the 2006 to 2010 period and is projected to grow almost fourfold from 2009 to 2035 (US EIA 2011). The number of unconventional natural gas wells in the US rose from 18,485 in 2004 to 25,145 in 2007 and is expected to continue increasing through at least 2020 (Vidas and Hugman 2008). With this expansion, it is becoming increasingly common for unconventional natural gas development (NGD) to occur near where people live, work, and play. People living near these development sites are raising public health concerns, as rapid NGD exposes more people to various potential stressors (COGCC 2009a).

The process of unconventional NGD is typically divided into two phases: well development and production (EPA 2010a, US DOE 2009). Well development involves pad preparation, well drilling, and well completion. The well completion process has three primary stages: 1) completion transitions (concrete well plugs are installed in wells to separate fracturing stages and then drilled out to release gas for production); 2) hydraulic fracturing ("fracking": the high pressure injection of water, chemicals, and propants into the drilled well to release the

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[1] BTEX, benzene, toluene, ethylbenzene, and xylenes; COGCC, Colorardo Oil and Gas Conservation Commission; HAP, hazardous air pollutant; HI, hazard index; HIA, health impact assessment; HQ, hazard quotient; NATA, National Air Toxics Assessment; NGD, natural gas development

natural gas); and 3) flowback, the return of fracking and geologic fluids, liquid hydrocarbons ("condensate") and natural gas to the surface (EPA 2010a, US DOE 2009). Once development is complete, the "salable" gas is collected, processed, and distributed. While methane is the primary constituent of natural gas, it contains many other chemicals, including alkanes, benzene, and other aromatic hydrocarbons (TERC 2009).

As shown by ambient air studies in Colorado, Texas, and Wyoming, the NGD process results in direct and fugitive air emissions of a complex mixture of pollutants from the natural gas resource itself as well as diesel engines, tanks containing produced water, and on site materials used in production, such as drilling muds and fracking fluids (CDPHE 2009; Frazier 2009; Walther 2011; Zielinska et al. 2011). The specific contribution of each of these potential NGD sources has yet to be ascertained and pollutants such as petroleum hydrocarbons are likely to be emitted from several of these NGD sources. This complex mixture of chemicals and resultant secondary air pollutants, such as ozone, can be transported to nearby residences and population centers (Walther 2011, GCPH 2010).

Multiple studies on inhalation exposure to petroleum hydrocarbons in occupational settings as well as residences near refineries, oil spills and petrol stations indicate an increased risk of eye irritation and headaches, asthma symptoms, acute childhood leukemia, acute myelogenous leukemia, and multiple myeloma (Glass et al. 2003; Kirkeleit et al. 2008; Brosselin et al. 2009; Kim et al. 2009; White et al. 2009). Many of the petroleum hydrocarbons observed in these studies are present in and around NGD sites (TERC 2009). Some, such as benzene, ethylbenzene, toluene, and xylene (BTEX) have robust exposure and toxicity knowledge bases, while toxicity information for others, such as heptane, octane, and diethylbenzene, is more limited. Assessments in Colorado have concluded that ambient benzene levels demonstrate an increased potential risk of developing cancer as well as chronic and acute non-cancer health effects in areas of Garfield County Colorado where NGD is the only major industry other than agriculture (CDPHE 2007; Coons and Walker 2008;CDPHE 2010). Health effects associated with benzene include acute and chronic nonlymphocytic leukemia, acute myeloid leukemia, chronic lymphocytic leukemia, anemia, and other blood disorders and immunological effects. (ATSDR 2007, IRIS 2010). In addition, maternal exposure to ambient levels of benzene recently has been associated with an increase in birth prevalence of neural tube defects (Lupo 2010). Health effects of xylene exposure include eye, nose, and throat irritation, difficulty in breathing, impaired lung function, and nervous system impairment (ATSDR 2007b). In addition, inhalation of xylenes, benzene, and alkanes can adversely affect the nervous system (Carpenter et al. 1978; Nilsen et al. 1988; Galvin et al. 1999; ATSDR 2007a; ATSDR 2007b).

Previous assessments are limited in that they were not able to distinguish between risks from ambient air pollution and specific NGD stages, such as well completions or risks between residents living near wells and residents living further from wells. We were able to isolate risks to residents living near wells during the flowback stage of well completions by using air quality data collected at the perimeter of the wells while flowback was occurring.

Battlement Mesa (population ~ 5,000) located in rural Garfield County, Colorado is one community experiencing the rapid expansion of NGD in an unconventional tight sand resource. A NGD operator has proposed developing 200 gas wells on 9 well pads located as close as 500 feet from residences. Colorado Oil and Gas Commission (COGCC) rules allow natural gas wells to be placed as close as 150 feet from residences (COGCC 2009b). Because of community concerns, as described elsewhere, we conducted a health impact assessment (HIA) to assess how the project may impact public health (Witter et al. 2011), working with a range of stakeholders to identify the potential public health risks and benefits.

In this article, we illustrate how a risk assessment was used to support elements of the HIA process and inform risk prevention recommendations by estimating chronic and subchronic non-cancer hazard indices (HIs) and lifetime excess cancer risks due to NGD air emissions.

2.0 Methods

We used standard United States Environmental Protection Agency (EPA) methodology to estimate non-cancer HIs and excess lifetime cancer risks for exposures to hydrocarbons (US EPA 1989, US EPA 2004) using residential exposure scenarios developed for the NGD project. We used air toxics data collected in Garfield County from January 2008 to November 2010 as part of a special study of short term exposures as well as on-going ambient air monitoring program data to estimate subchronic and chronic exposures and health risks (Frazier 2009, GCPH 2009, GCPH 2010, GCPH 2011, Antero 2010).

2.1 Sample collection and analysis:

All samples were collected and analyzed according to published EPA methods. Analyses were conducted by EPA certified laboratories. The Garfield County Department of Public Health (GCPH) and Olsson Associates, Inc. (Olsson) collected ambient air samples into evacuated SUMMA® passivated stainless-steel canisters over 24-hour intervals. The GCPH collected the samples from a fixed monitoring station and along the perimeters of four well pads and shipped samples to Eastern Research Group for analysis of 78 hydrocarbons using EPA’s compendium method TO-12, Method for the Determination of Non-Methane Organic Compounds in Ambient Air Using Cyrogenic Preconcentration and Direct Flame Ionization Detection (US EPA 1999). Olsson collected samples along the perimeter of one well pad and shipped samples to Atmospheric Analysis and Consulting, Inc. for analysis of 56 hydrocarbons (a subset of the 78 hydrocarbons determined by Eastern Research Group) using method TO-12. Per method TO-12, a fixed volume of sample was cryogenically concentrated and then desorbed onto a gas chromatography column equipped with a flame ionization detector. Chemicals were identified by retention time and reported in a concentration of parts per billion carbon (ppbC). The ppbC values were converted to micrograms per cubic meter ($\mu g/m^3$) at 01.325 kilo Pascals and 298.15 Kelvin.

Two different sets of samples were collected from rural (population < 50,000) areas in western Garfield County over varying time periods. The main economy, aside from the NGD industry, of western Garfield County is agricultural. There is no other major industry.

2.1.1 NGD Area Samples

The GCPH collected ambient air samples every six days between January 2008 and November 2010 (163 samples) from a fixed monitoring station located in the midst of rural home sites and ranches and NGD, during both the well development and production. The site is located on top of a small hill and 4 miles upwind of other potential emission sources, such as a major highway (Interstate-70) and the town of Silt, CO (GCPH 2009, GCPH 2010, GCPH 2011).

2.1.2 Well Completion Samples

The GCPH collected 16 ambient air samples at each cardinal direction along 4well pad perimeters (130 to 500 feet from the well pad center) in rural Garfield County during well completion activities. The samples were collected on the perimeter of 4 well pads being developed by 4 different natural gas operators in summer 2008 (Frazier 2009). The GCPH worked closely with the NGD operators to ensure these air samples were collected during the period while at least one well was on uncontrolled (emissions not controlled) flowback into collection tanks vented directly to the air. The number of wells on each pad and other activities occurring on the pad were not documented. Samples were collected over 24 to 27-hour intervals, and samples included emissions from both uncontrolled flowback and diesel engines (i.e., from. trucks and generators supporting completion activities). In addition, the GCPH collected a background sample 0.33 to 1 mile from each well pad (Frazier 2009). The highest hydrocarbon levels corresponded to samples collected directly downwind of the tanks (Frazier 2009, Antero 2010). The lowest hydrocarbon levels corresponded either to background samples or samples collected upwind of the flowback tanks (Frazier 2009, Antero 2010).

Antero Resources Inc., a natural gas operator, contracted Olsson to collect eight 24-hour integrated ambient air samples at each cardinal direction at 350 and 500 feet from the well pad center during well completion activities conducted on one of their well pads in summer 2010 (Antero 2010). Of the 12 wells on this pad, 8 were producing salable natural gas; 1 had been drilled but not completed; 2 were being hydraulically fractured during daytime hours, with ensuing uncontrolled flowback during nighttime hours; and 1 was on uncontrolled flowback during nighttime hours.

All five well pads are located in areas with active gas production, approximately one mile from Interstate-70.

2.2 Data assessment

We evaluated outliers and compared distributions of chemical concentrations from NGD area and well completion samples using Q-Q plots and the Mann-Whitney U test, respectively, in EPA's ProUCL version 4.00.05 software (US EPA 2010b). The Mann-Whitney U test was used because the measurement data were not normally distributed. Distributions were considered as significantly different at an alpha of 0.05. Per EPA guidance, we assigned the exposure concentration as either the 95 percent upper confidence limit (UCL) of the mean concentration for compounds found in 10 or more samples or the maximum detected concentration for compounds found in more than 1 but fewer than 10 samples. This latter category included three compounds: 1,3-butadiene, 2,2,4-trimethylpentane, and styrene in the well completion samples. EPA's ProUCL software was used to select appropriate methods based on sample distributions and detection frequency for computing 95 percent UCLs of the mean concentration (US EPA 2010b).

2.3 Exposure assessment

Risks were estimated for two populations: (1) residents > ½ mile from wells; and (2) residents ≤½ mile from wells. We defined residents ≤ ½ mile from wells as living near wells, based on residents reporting odor complaints attributed to gas wells in the summer of 2010 (COGCC 2011).

Exposure scenarios were developed for chronic non-cancer HIs and cancer risks. For both populations, we assumed a 30-year project duration based on an estimated 5-year well development period for all well pads, followed by 20 to 30 years of production. We assumed a resident lives, works, and otherwise remains within the town 24 hours/day, 350 days/year and that lifetime of a resident is 70 years, based on standard EPA reasonable maximum exposure (RME) defaults (US EPA 1989).

2.3.1 Residents > ½ mile from well pads

As illustrated in Figure 1, data from the NGD area samples were used to estimate chronic and subchronic risks for residents > ½ mile from well development and production throughout the project. The exposure concentrations for this population were the 95 percent UCL on the mean concentration and median concentration from the 163 NGD samples.

2.3.2 Residents ≤ ½ mile from well pads

To evaluate subchronic non-cancer HIs from well completion emissions, we estimated that a resident lives ≤ ½ mile from two well pads resulting a 20- month exposure duration based on 2 weeks per well for completion and 20 wells per pad, assuming some overlap between activities. The subchronic exposure concentrations for this population were the 95 percent UCL on the mean concentration and the median concentration from the 24 well completion samples. To evaluate chronic risks to residents ≤ ½ mile from wells throughout the NGD project, we calculated a time-weighted exposure concentration (C_{S+c}) to account for exposure to emissions from well completions for 20-months followed by 340 months of exposure to emissions from the NGD area using the following formula:

$$C_{S+c} = (C_c \times ED_c/ED) + (C_S \times ED_S/ED)$$

where:

C_c = Chronic exposure point concentration (μg/m^3) based on the 95 percent UCL of the mean concentration or median concentration from the 163 NGD area samples

ED_c = Chronic exposure duration

C_S = Subchronic exposure point concentration (μg/m^3) based on the 95 percent UCL of the mean concentration or median concentration from the 24 well completion samples

ED_S = Subchronic exposure duration

ED = Total exposure duration

2.4 Toxicity assessment and risk characterization

For non-carcinogens, we expressed inhalation toxicity measurements as a reference concentration (RfC in units of μg/m^3 air). We used chronic RfCs to evaluate long-term exposures of 30 years and subchronic RfCs to evaluate subchronic exposures of 20-months. If a subchronic

RfC was not available, we used the chronic RfC. We obtained RfCs from (in order of preference) EPA's Integrated Risk Information System (IRIS) (U. S. EPA 2011), California Environmental Protection Agency (CalEPA) (CalEPA 2003), EPA's Provisional Peer-Reviewed Toxicity Values (ORNL 2009), and Health Effects Assessment Summary Tables (U.S. EPA 1997). We used surrogate RfCs according to EPA guidance for C_5 to C_{18} aliphatic and C_6 to C_{18} aromatic hydrocarbons which did not have a chemical-specific toxicity value (U.S. EPA 2009a). We derived semi-quantitative hazards, in terms of the hazard quotient (HQ), defined as the ratio between an estimated exposure concentration and RfC. We summed HQs for individual compounds to estimate the total cumulative HI. We then separated HQs specific to neurological, respiratory, hematological, and developmental effects and calculated a cumulative HI for each of these specific effects.

For carcinogens, we expressed inhalation toxicity measurements as inhalation unit risk (IUR) in units of risk per $\mu g/m^3$. We used IURs from EPA's IRIS (US EPA 2011) when available or the CalEPA (CalEPA 2003). The lifetime cancer risk for each compound was derived by multiplying estimated exposure concentration by the IUR. We summed cancer risks for individual compounds to estimate the cumulative cancer risk. Risks are expressed as excess cancers per 1 million population based on exposure over 30 years.

Toxicity values (i.e., RfCs or IURs) or a surrogate toxicity value were available for 45 out of 78 hydrocarbons measured. We performed a quantitative risk assessment for these hydrocarbons. The remaining 33 hydrocarbons were considered qualitatively in the risk assessment.

3.0 Results

3.1 Data assessment

Evaluation of potential outliers revealed no sampling, analytical, or other anomalies were associated with the outliers. In addition, removal of potential outliers from the NGD area samples did not change the final HIs and cancer risks. Potential outliers in the well completion samples were associated with samples collected downwind from flowback tanks and are representative of emissions during flowback. Therefore, no data was removed from either data set.

Descriptive statistics for concentrations of the hydrocarbons used in the quantitative risk assessment are presented in Table 1. A list of the hydrocarbons detected in the samples that were considered qualitatively in the risk assessment because toxicity values were not available is presented in Table 2. Descriptive statistics for all hydrocarbons are available in Supplemental Table 1. Two thirds more hydrocarbons were detected at a frequency of 100 percent in the well completion samples (38 hydrocarbons) than in the NGD area samples (23 hydrocarbons). Generally, the highest alkane and aromatic hydrocarbon median concentrations were observed in the well completion samples, while the highest median concentrations of several alkenes were observed in the NGD area samples. Median concentrations of benzene, ethylbenzene, toluene, and m-xylene/p-xlyene were 2.7, 4.5, 4.3, and 9 times higher in the well completion samples than in the NGD area samples, respectively. Wilcoxon-Mann-Whitney test results indicate that concentrations of hydrocarbons from well completion samples were significantly higher than concentrations from NGD area samples ($p<0.05$) with the exception of 1,2,3-trimethylbenzene, n-pentane, 1,3-butadiene, isopropylbenzene, n-propylbenzene, propylene, and styrene (Supplemental Table 2).

3.2 Non-cancer hazard indices

Table 3 presents chronic and subchronic RfCs used in calculating non-cancer HIs, as well critical effects and other effects. Chronic non-cancer HQ and HI estimates based on ambient air concentrations are presented in Table 4. The total chronic HIs based on the 95% UCL of the mean concentration were 0.4 for residents > ½ mile from wells and 1 for residents ≤ ½ mile from wells. Most of the chronic non-cancer hazard is attributed to neurological effects with neurological HIs of 0.3 for residents > ½ mile from wells and 0.9 for residents ≤ ½ mile from wells.

Total subchronic non-cancer HQs and HI estimates are presented in Table 5. The total subchronic HIs based on the 95% UCL of the mean concentration were 0.2 for residents > ½ mile from wells and 5 for residents ≤ ½ mile from wells. The subchronic non-cancer hazard for residents > ½ mile from wells is attributed mostly to respiratory effects (HI = 0.2), while the subchronic hazard for residents ≤ ½ mile from wells is attributed to neurological (HI = 4), respiratory (HI = 2), hematologic (HI = 3), and developmental (HI =1) effects.

For residents > ½ mile from wells, aliphatic hydrocarbons (51 percent), trimethylbenzenes (22 percent), and benzene (14 percent) are primary contributors to the chronic non-cancer HI. For residents ≤ ½ mile from wells, trimethylbenzenes (45 percent), aliphatic hydrocarbons (32 percent), and xylenes (17 percent) are primary contributors to the chronic non-cancer HI, and trimethylbenzenes (46 percent), aliphatic hydrocarbons (21 percent) and xylenes (15 percent) also are primary contributors to the subchronic HI.

3.3 Cancer Risks

Cancer risk estimates calculated based on measured ambient air concentrations are presented in Table 6. The cumulative cancer risks based on the 95% UCL of the mean concentration were 6 in a million for residents > ½ from wells and 10 in a million for residents ≤

½ mile from wells. Benzene (84 percent) and 1,3-butadiene (9 percent) were the primary contributors to cumulative cancer risk for residents > ½ mile from wells. Benzene (67 percent) and ethylbenzene (27 percent) were the primary contributors to cumulative cancer risk for residents ≤ ½ mile from wells.

4.0 Discussion

Our results show that the non-cancer HI from air emissions due to natural gas development is greater for residents living closer to wells. Our greatest HI corresponds to the relatively short-term (i.e., subchronic), but high emission, well completion period. This HI is driven principally by exposure to trimethylbenzenes, aliphatic hydrocarbons, and xylenes, all of which have neurological and/or respiratory effects. We also calculated higher cancer risks for residents living nearer to wells as compared to residents residing further from wells. Benzene is the major contributor to lifetime excess cancer risk for both scenarios. It also is notable that these increased risk metrics are seen in an air shed that has elevated ambient levels of several measured air toxics, such as benzene (CDPHE 2009, GCPH 2010).

4.1 Representation of Exposures from NGD

It is likely that NGD is the major source of the hydrocarbons observed in the NGD area samples used in this risk assessment. The NGD area monitoring site is located in the midst of multi-acre rural home sites and ranches. Natural gas is the only industry in the area other than agriculture. Furthermore, the site is at least 4 miles upwind from any other major emission source, including Interstate 70 and the town of Silt, Colorado. Interestingly, levels of benzene, m,p-xylene, and 1,3,5-trimethylbenzene measured at this rural monitoring site in 2009 were higher than levels measured at 27 out of 37 EPA air toxics monitoring sites where SNMOCs were measured, including urban sites such as Elizabeth, NJ, Dearborn, MI, and Tulsa, OK

(GCPH 2010, US EPA 2009b). In addition, the 2007 Garfield County emission inventory attributes the bulk of benzene, xylene, toluene, and ethylbenzene emissions in the county to NGD, with NGD point and non-point sources contributing five times more benzene than any other emission source, including on-road vehicles, wildfires, and wood burning. The emission inventory also indicates that NGD sources (e.g. condensate tanks, drill rigs, venting during completions, fugitive emissions from wells and pipes, and compressor engines) contributed ten times more VOC emissions than any source, other than biogenic sources (e.g plants, animals, marshes, and the earth) (CDPHE 2009).

Emissions from flowback operations, which may include emissions from various sources on the pads such as wells and diesel engines, are likely the major source of the hydrocarbons observed in the well completion samples. These samples were collected very near (130 to 500 feet from the center) well pads during uncontrolled flowback into tanks venting directly to the air. As for the NGD area samples, no sources other than those associated with NGD were in the vicinity of the sampling locations.

Subchronic health effects, such as headaches and throat and eye irritation reported by residents during well completion activities occurring in Garfield County, are consistent with known health effects of many of the hydrocarbons evaluated in this analysis (COGCC 2011; Witter et al. 2011). Inhalation of trimethylbenzenes and xylenes can irritate the respiratory system and mucous membranes with effects ranging from eye, nose, and throat irritation to difficulty in breathing and impaired lung function (ATSDR 2007a; ATSDR 2007b; US EPA 1994). Inhalation of trimethylbenzenes, xylenes, benzene, and alkanes can adversely affect the nervous system with effects ranging from dizziness, headaches, fatigue at lower exposures to numbness in the limbs, incoordination, tremors, temporary limb paralysis, and unconsciousness at higher exposures (Carpenter et al. 1978; Nilsen et al. 1988; US EPA 1994; Galvin et al. 1999; ATSDR 2007a; ATSDR 2007b).

4.2 Risk Assessment as a Tool for Health Impact Assessment

HIA is a policy tool used internationally that is being increasingly used in the United States to assess multiple complex hazards and exposures in communities. Comparison of risks between residents based on proximity to wells illustrates how the risk assessment process can be used to support the HIA process. An important component of the HIA process is to identify where and when public health is most likely to be impacted and to recommend mitigations to reduce or eliminate the potential impact (Collins and Koplan 2009). This risk assessment indicates that public health most likely would be impacted by well completion activities, particularly for residents living nearest the wells. Based on this information, suggested risk prevention strategies in the HIA are directed at minimizing exposures for those living closet to the well pads, especially during well completion activities when emissions are the highest. The HIA includes recommendations to (1) control and monitor emissions during completion transitions and flowback; (2) capture and reduce emissions through use of low or no emission flowback tanks; and (3) establish and maintain communications regarding well pad activities with the community (Witter et al 2011).

4.3 Comparisons to Other Risk Estimates

This risk assessment is one of the first studies in the peer-reviewed literature to provide a scientific perspective to the potential health risks associated with development of unconventional natural gas resources. Our results for chronic non-cancer HIs and cancer risks for residents > than ½ mile from wells are similar to those reported for NGD areas in the relatively few previous risk assessments in the non-peer reviewed literature that have addressed this issue

(CDPHE 2010, Coons and Walker 2008, CDPHE 2007, Walther 2011). Our risk assessment differs from these previous risk assessments in that it is the first to separately examine residential populations nearer versus further from wells and to report health impact of emissions resulting from well completions. It also adds information on exposure to air emissions from development of these resources. These data show that it is important to include air pollution in the national dialogue on unconventional NGD that, to date, has largely focused on water exposures to hydraulic fracturing chemicals.

4.4 Limitations

As with all risk assessments, scientific limitations may lead to an over- or underestimation of the actual risks. Factors that may lead to overestimation of risk include use of: 1) 95 percent UCL on the mean exposure concentrations; 2) maximum detected values for 1,3-butadiene, 2,2,4-trimethylpentane, and styrene because of a low number of detectable measurements; 3) default RME exposure assumptions, such as an exposure time of 24 hours per day and exposure frequency of 350 days per year; and 4) upper bound cancer risk and non-cancer toxicity values for some of our major risk drivers. The benzene IUR, for example, is based on the high end of a range of maximum likelihood values and includes uncertainty factors to account for limitations in the epidemiological studies for the dose-response and exposure data (US EPA 2011a). Similiarly, the xylene chronic RfC is adjusted by a factor of 300 to account for uncertainties in extrapolating from animal studies, variability of sensitivity in humans, and extrapolating from subchronic studies (US EPA 2011a). Our use of chronic RfCs values when subchronic RfCs were not available may also have overestimated 1,3-butadiene, n-propylbenzene, and propylene subchronic HQs. None of these three chemicals, however, were primary contributors to the subchronic HI, so their overall effect on the HI is relatively small.

Several factors may have lead to an underestimation of risk in our study results. We were not able to completely characterize exposures because several criteria or hazardous air pollutants directly associated with the NGD process via emissions from wells or equipment used to develop wells, including formaldehyde, acetaldehyde, crotonaldehyde, naphthalene, particulate matter, and polycyclic aromatic hydrocarbons, were not measured. No toxicity values appropriate for quantitative risk assessment were available for assessing the risk to several alkenes and low molecular weight alkanes (particularly $< C_5$ aliphatic hydrocarbons). While at low concentrations the toxicity of alkanes and alkenes is generally considered to be minimal (Sandmeyer, 1981), the maximum concentrations of several low molecular weight alkanes measured in the well completion samples exceeded the 200 - 1000μg/m^3 range of the RfCs for the three alkanes with toxicity values: n-hexane, n-pentane, and n-nonane (US EPA 2011a, ORNL 2009). We did not consider health effects from acute (i.e., less than one hour) exposures to peak hydrocarbon emissions because there were not appropriate measurements. Previous risk assessments have estimated an acute HQ of 6 from benzene in grab samples collected when residents noticed odors they attributed to NGD (CDPHE 2007). We did not include ozone or other potentially relevant exposure pathways such as ingestion of water and inhalation of dust in this risk assessment because of a lack of available data. Elevated concentrations of ozone precursors (specifically, VOCs and nitrogen oxides) have been observed in Garfield County's NGD area and the 8-hr average ozone concentration has periodically approached the 75 ppb National Ambient Air Quality Standard (NAAQS) (CDPHE 2009, GCPH 2010).

This risk assessment also was limited by the spatial and temporal scope of available monitoring data. For the estimated chronic exposure, we used 3 years of monitoring data to estimate exposures over a 30 year exposure period and a relatively small database of 24 samples collected at varying distances up to 500 feet from a well head (which also were used to estimate shorter-term non-cancer hazard index). Our estimated 20-month subchronic exposure was limited to samples collected in the summer, which may have not have captured temporal variation in well completion emissions. Our ½ mile cut point for defining the two different exposed populations in our exposure scenarios was based on complaint reports from residents living within ½ mile of existing NGD, which were the only data available. The actual distance at which residents may experience greater exposures from air emissions may be less than or greater than a ½ mile, depending on dispersion and local topography and meteorology. This lack of spatially and temporally appropriate data increases the uncertainty associated with the results.

Lastly, this risk assessment was limited in that appropriate data were not available for apportionment to specific sources within NGD (e.g diesel emissions, the natural gas resource itself, emissions from tanks, etc.). This increases the uncertainty in the potential effectiveness of risk mitigation options.

These limitations and uncertainties in our risk assessment highlight the preliminary nature of our results. However, there is more certainty in the comparison of the risks between the populations and in the comparison of subchronic to chronic exposures because the limitations and uncertainties similarly affected the risk estimates.

4.5 Next Steps

Further studies are warranted, in order to reduce the uncertainties in the health effects of exposures to NGD air emissions, to better direct efforts to prevent exposures, and thus address the limitations of this risk assessment. Next steps should include the modeling of short- and longer-term exposures as well as collection of area, residential, and personal exposure data, particularly for peak short-term emissions. Furthermore, studies should examine the toxicity of hydrocarbons, such as alkanes, including health effects of mixtures of HAPs and other air pollutants associated with NGD. Emissions from specific emission sources should be characterized and include development of dispersion profiles of HAPs. This emissions data, when coupled with information on local meteorological conditions and topography, can help provide guidance on minimum distances needed to protect occupant health in nearby homes, schools, and businesses. Studies that incorporate all relevant pathways and exposure scenarios, including occupational exposures, are needed to better understand the impacts of NGD of unconventional resources, such as tight sands and shale, on public health. Prospective medical monitoring and surveillance for potential air pollution-related health effects is needed for populations living in areas near the development of unconventional natural gas resources.

5.0 Conclusions

Risk assessment can be used as a tool in HIAs to identify where and when public health is most likely to be impacted and to inform risk prevention strategies directed towards efficient reduction of negative health impacts. These preliminary results indicate that health effects resulting from air emissions during development of unconventional natural gas resources are most likely to occur in residents living nearest to the well pads and warrant further study. Risk prevention efforts should be directed towards reducing air emission exposures for persons living and working near wells during well completions.

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Figure 1: Relationship between completion samples and natural gas development area samples and residents living ≤ ½ mile and > ½ mile from wells.

[a]Time weighted average based on 20-month contribution from well completion samples and 340- month contribution from natural gas development samples.

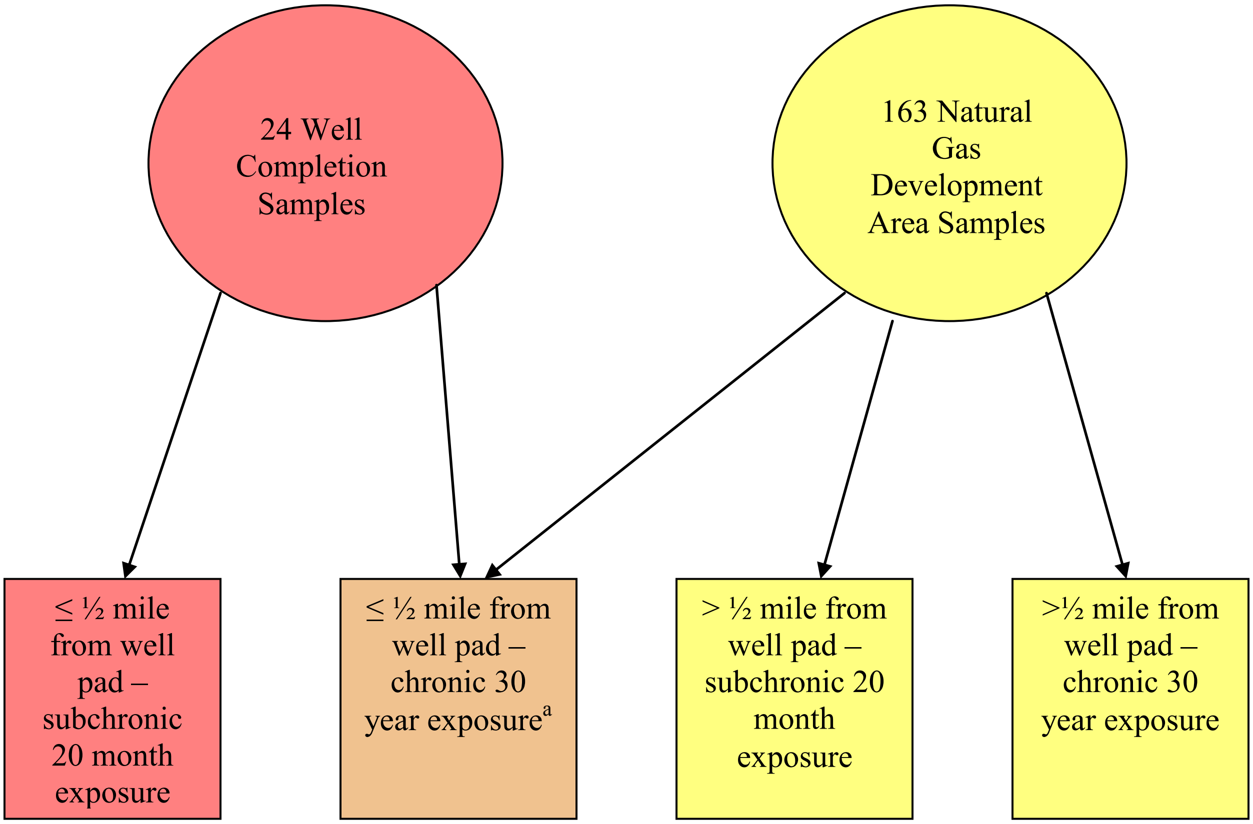
24 Well Completion Samples
163 Natural Gas Development Area Samples
≤ ½ mile from well pad – subchronic 20 month exposure
≤ ½ mile from well pad – chronic 30 year exposure[a]
> ½ mile from well pad – subchronic 20 month exposure
>½ mile from well pad – chronic 30 year exposure

Table 1: Descriptive statistics for hydrocarbon concentrations with toxicity values in 24-hour integrated samples collected in NGD area and samples collected during well completions

	NGD Area Sample Results[a]							Well Completion Sample Results[b]						
Hydrocarbon (μg/m^3)	No.	% > MDL	Med	SD	95% UCL[c]	Min	Max	No.	% > MDL	Med	SD	95% UCL[c]	Min	Max
1,2,3-Trimethylbenzene	163	39	0.11	0.095	0.099	0.022	0.85	24	83	0.84	2.3	3.2	0.055	12
1,2,4-Trimethylbenzene	163	96	0.18	0.34	0.31	0.063	3.1	24	100	1.7	17	21	0.44	83
1,3,5-Trimethylbenzene	163	83	0.12	0.13	0.175	0.024	1.2	24	100	1.3	16	19.5	0.33	78
1,3-Butadiene	163	7	0.11	0.020	0.0465	0.025	0.15	16	56	0.11	0.021	NC	0.068	0.17
Benzene	163	100	0.95	1.3	1.7	0.096	14	24	100	2.6	14	20	0.94	69
Cyclohexane	163	100	2.1	8.3	6.2	0.11	105	24	100	5.3	43	58	2.21	200
Ethylbenzene	163	95	0.17	0.73	0.415	0.056	8.1	24	100	0.77	47	54	0.25	230
Isopropylbenzene	163	38	0.15	0.053	0.074	0.020	0.33	24	67	0.33	1.0	1.0	0.0	4.8
Methylcyclohexane	163	100	3.7	4.0	6.3	0.15	24	24	100	14	149	190	3.1	720
m-Xylene/p-Xylene	163	100	0.87	1.2	1.3	0.16	9.9	24	100	7.8	194	240	2.0	880
n-Hexane	163	100	4.0	4.2	6.7	0.13	25	24	100	7.7	57	80	1.7	255
n-Nonane	163	99	0.44	0.49	0.66	0.064	3.1	24	100	3.6	61	76	1.2	300
n-Pentane	163	100	9.1	9.8	14	0.23	62	24	100	11	156	210	3.9	550
n-Propylbenzene	163	66	0.10	0.068	0.10	0.032	0.71	24	88	0.64	2.4	3.3	0.098	12
o-Xylene	163	97	0.22	0.33	0.33	0.064	3.6	24	100	1.2	40	48.5	0.38	190
Propylene	163	100	0.34	0.23	0.40	0.11	2.5	24	100	0.41	0.34	0.60	0.16	1.9
Styrene	163	15	0.15	0.26	0.13	0.017	3.4	24	21	0.13	1.2	NC	0.23	5.9
Toluene	163	100	1.8	6.2	4.8	0.11	79	24	100	7.8	67	92	2.7	320
Aliphatic hydrocarbons $C_5 – C_8$[d]	163	NC	29	NA	44	1.7	220	24	NC	56	NA	780	24	2700
Aliphatic hydrocarbons $C_9 – C_{18}$[e]	163	NC	1.3	NA	14	0.18	400	24	NC	7.9	NA	100	1.4	390
Aromatic hydrocarbons $C_9 – C_{18}$[f]	163	NC	0.57	NA	0.695	0.17	5.6	24	NC	3.7	NA	27	0.71	120

Abbreviations: Max, maximum detected concentration; Med, median; Min, minimum detected concentration; NGD, natural gas development; NC, not calculated; No., number of samples; SD, standard deviation; %>MDL, percent greater than method detection limit; μg/m^3 micrograms per cubic meter; 95% UCL 95 percent upper confidence limit on the mean

[a] Samples collected at one site every 6 six days between 2008 and 2010.

[b] Samples collected at four separate sites in summer 2008 and one site in summer 2010.

[c] Calculated using EPA's ProUCL version 4.00.05 software (U. S. EPA 2010)

[d] Sum of 2,2,2-trimethylpentane, 2,2,4-trimethylpentane, 2,2-dimethylbutane, 2,3,4-trimethylpentane, 2,3-dimethylbutane, 2,3-dimethylpentane, 2,4-dimethylpentane, 2-methylheptane, 2-methylhexane, 2-methylpentane, 3-methylheptane, 3-methylhexane, 3-methylpentane, cyclopentane, isopentane, methylcyclopentane, n-heptane, n-octane

[e] Sum of n-decane, n-dodecane, n-tridecane, n-undecane

[f] Sum of m-diethylbenzene, m-ethyltoluene, o-ethyltoluene, p-diethylbenzene, p-ethyltoluene

Table 2: Detection frequencies of hydrocarbons without toxicity values detected in NGD area or well completion samples.

Hydrocarbon	NGD Area Sample[a] Detection Frequency (%)	Well Completion Sample[b] Detection Frequency (%)
1-Dodecene	36	81
1-Heptene	94	100
1-Hexene	63	79
1-Nonene	52	94
1-Octene	29	75
1-Pentene	98	79
1-Tridecene	7	38
1-Undecene	28	81
2-Ethyl-1-butene	1	0
2-Methyl-1-butene	29	44
2-Methyl-1-pentene	1	6
2-Methyl-2-butene	36	69
3-Methyl-1-butene	6	6
4-Methyl-1-pentene	16	69
Acetylene	100	92
a-Pinene	63	100
b-Pinene	10	44
cis-2-Butene	58	75
cis-2-Hexene	13	81
cis-2-Pentene	38	54
Cyclopentene	44	94
Ethane	100	100
Ethylene	100	100
Isobutane	100	100
Isobutene/1-Butene	73	44
Isoprene	71	96
n-Butane	98	100
Propane	100	100
Propyne	1	0
trans-2-Butene	80	75
trans-2-Hexene	1	6
trans-2-Pentene	55	83

Abbreviations: NGD, natural gas development

[a] Samples collected at one site every 6 six days between 2008 and 2010.

[b] Samples collected at four separate sites in summer 2008 and one site in summer 2010.

Table 3: Chronic and subchronic reference concentrations, critical effects, and major effects for hydrocarbons in quantitative risk assessment

Hydrocarbon	Chronic		Subchronic		Critical Effect/ Target Organ	Other Effects
	RfC ($\mu g/m^3$)	Source	RfC ($\mu g/m^3$)	Source		
1,2,3-Trimethylbenzene	5.00E+00	PPTRV	5.00E+01	PPTRV	neurological	respiratory, hematological
1,3,5-Trimethylbenzene	6.00E+00	PPTRV	1.00E+01	PPTRV	neurological	hematological
Isopropylbenzene	4.00E+02	IRIS	9.00E+01	HEAST	renal	neurological, respiratory
n-Hexane	7.00E+02	IRIS	2.00E+03	PPTRV	neurological	-
n-Nonane	2.00E+02	PPTRV	2.00E+03	PPTRV	neurological	respiratory
n-Pentane	1.00E+03	PPTRV	1.00E+04	PPTRV	neurological	-
Styrene	1.00E+03	IRIS	3.00E+03	HEAST	neurological	-
Toluene	5.00E+03	IRIS	5.00E+03	PPTRV	neurological	developmental, respiratory
Xylenes, total	1.00E+02	IRIS	4.00E+02	PPTRV	neurological	developmental, respiratory
n-propylbenzene	1.00E+03	PPTRV	1.00E+03	Chronic RfC PPTRV	developmental	Neurological
1,2,4-Trimethylbenzene	7.00E+00	PPTRV	7.00E+01	PPTRV	decrease in blood clotting time	neurological, respiratory
1,3-Butadiene	2.00E+00	IRIS	2.00E+00	Chronic RfC IRIS	reproductive	neurological, respiratory
Propylene	3.00E+03	CalEPA	1.00E+03	Chronic RfC CalEPA	respiratory	-
Benzene	3.00E+01	ATSDR	8.00E+01	PPTRV	decreased lymphocyte count	neurological, developmental, reproductive
Ethylbenzene	1.00E+03	ATSDR	9.00E+03	PPTRV	auditory	neurological, respiratory, renal
Cyclohexane	6.00E+03	IRIS	1.80E+04	PPTRV	developmental	neurological
Methylcyclohexane	3.00E+03	HEAST	3.00E+03	HEAST	renal	-
Aliphatic hydrocarbons $C_5 – C_8$[a]	6E+02	PPTRV	2.7E+04	PPTRV	neurological	-
Aliphatic hydrocarbons $C_9 – C_{18}$	1E+02	PPTRV	1E+02	PPTRV	respiratory	-
Aromatic hydrocarbons $C_9 – C_{18}$[b]	1E+02	PPTRV	1E+03	PPRTV	decreased maternal body weight	respiratory

Abbreviations: 95%UCL, 95 percent upper confidence limit; CalEPA, California Environmental Protection Agency; HEAST, EPA Health Effects Assessment Summary Tables 1997; HQ, hazard quotient; IRIS, Integrated Risk Information System; Max, maximum; PPTRV, EPA Provisional Peer-Reviewed Toxicity Value; RfC, reference concentration; $\mu g/m^3$, micrograms per cubic meter. Data from CalEPA 2011; IRIS (US EPA 2011a); ORNL 2011.

[a] Based on PPTRV for commercial hexane.

[b] Based on PPTRV for high flash naphtha.

Table 4: Chronic hazard quotients and hazard indices for residents living > ½ mile from wells and residents living ≤ ½ mile from wells.

	> ½ mile		≤ ½ mile	
Hydrocarbon	Chronic HQ based on median Concentration	Chronic HQ based on 95% UCL of mean concentration	Chronic HQ based on median Concentration	Chronic HQ based on 95% UCL of mean concentration
1,2,3-Trimethylbenzene	2.09E-02	1.90E-02	2.87E-02	5.21E-02
1,2,4-Trimethylbenzene	2.51E-02	4.22E-02	3.64E-02	2.01E-01
1,3,5-Trimethylbenzene	1.96E-02	2.80E-02	3.00E-02	1.99E-01
1,3-Butadiene	5.05E-02	2.23E-02	5.05E-02	2.25E-02
Benzene	3.03E-02	5.40E-02	3.32E-02	8.70E-02
Cyclohexane	3.40E-04	9.98E-04	3.67E-04	1.46E-03
Ethylbenzene	1.63E-04	3.98E-04	1.95E-04	3.23E-03
Isopropylbenzene	3.68E-04	1.78E-04	3.90E-04	3.05E-04
Methylcyclohexane	1.18E-03	2.00E-03	1.36E-03	5.32E-03
n-Hexane	5.49E-03	9.23E-03	5.76E-03	1.47E-02
n-Nonane	2.11E-03	3.14E-03	2.95E-03	2.31E-02
n-Pentane	8.71E-03	1.32E-02	8.79E-03	2.39E-02
n-propylbenzene	9.95E-05	9.59E-05	1.28E-04	2.64E-04
Propylene	1.09E-04	1.27E-04	1.10E-04	1.30E-04
Styrene	1.43E-04	1.25E-04	1.42E-04	4.32E-04
Toluene	3.40E-04	9.28E-04	4.06E-04	1.86E-03
Xylenes, total	1.16E-02	1.57E-02	1.54E-02	1.71E-01
Aliphatic hydrocarbons $C_5 – C_8$	4.63E-02	7.02E-02	4.87E-02	1.36E-01
Aliphatic hydrocarbons $C_9 – C_{18}$	1.22E-02	1.35E-01	1.58E-02	1.83E-01
Aromatic hydrocarbons $C_9 – C_{18}$	5.44E-03	6.67E-03	7.12E-03	2.04E-02
Total Hazard Index	2E-01	4E-01	3E-01	1E+00
Neuorological EffectsHazard Index[a]	2E-01	3E-01	3E-01	9E-01
Respiratory Effects Hazard Index[b]	1E-01	2E-02	2E-02	7E-01
Hematogical Effects Hazard Index[c]	1E-01	1E-01	1E-01	5E-01
Developmental Effects Hazard Index[d]	4E-02	7E-02	5E-02	3E-01

Abbreviations: 95%UCL, 95 percent upper confidence limit; HQ, hazard quotient;

[a] Sum of HQs for hydrocarbons with neurological effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3,5-Trimethylbenzene, 1,3-butadiene, benzene, cyclohexane, ethylbenzene, isopropylbenzene, n-hexane, n-nonane, n-pentane, n-propylbenzene, styrene, toluene, xylenes, aliphatic C_5-C_8 hydrocarbons.

[b] Sum of HQs for hydrocarbons with respiratory effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3-butadiene, ethylbenzene, isopropylbenzene, n-nonane, propylene, toluene, xylenes, aliphatic C_9-C_{18} hydrocarbons, aromatic C_9-C_{18} hydrocarbons

[c] Sum of HQs for hydrocarbons with hematological effects: 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, benzene

[d] Sum of HQs for hydrocarbons with developmental effects: benzene, cyclohexane, toluene, and xylenes

Table 5: Subchronic hazard quotients and hazard indices residents living > ½ mile from wells and residents living ≤ ½ mile from wells.

	> ½ mile		≤ ½ mile	
Hydrocarbon (µg/m^3)	Subchronic HQ based on median concentration	Subchronic HQ based on 95% UCL of mean concentration	Subchronic HQ based on median concentration	Subchronic HQ based on 95% UCL of mean concentration
1,2,3-Trimethylbenzene	2.09E-03	1.90E-03	1.67E-02	6.40E-02
1,2,4-Trimethylbenzene	2.51E-03	4.22E-03	2.38E-02	3.02E-01
1,3,5-Trimethylbenzene	1.18E-02	1.68E-02	1.29E-01	1.95E+00
1,3-Butadiene	5.04E-02	2.23E-02	5.25E-02	8.30E-02
Benzene	1.14E-02	2.02E-02	3.25E-02	2.55E-01
Cyclohexane	1.13E-04	3.33E-04	2.93E-04	3.24E-03
Ethylbenzene	1.81E-05	4.42E-05	8.56E-05	5.96E-03
Isopropylbenzene	1.63E-03	7.92E-04	3.62E-03	1.14E-02
Methylcyclohexane	1.18E-03	2.01E-03	4.67E-03	6.47E-02
n-Hexane	1.92E-03	3.23E-03	3.86E-03	3.98E-02
n-Nonane	2.11E-04	3.14E-04	1.80E-03	3.78E-02
n-Pentane	8.71E-04	1.32E-03	1.05E-03	2.13E-02
n-propylbenzene	9.95E-05	9.57E-05	6.36E-04	3.26E-03
Propylene	1.43E-04	3.80E-04	4.12E-04	6.02E-04
Styrene	5.68E-04	4.16E-05	4.00E-06	1.97E-03
Toluene	4.18E-05	9.28E-04	2.46E-04	1.84E-02
Xylenes, total	2.91E-03	3.93E-03	2.05E-02	7.21E-01
Aliphatic hydrocarbons $C_5 – C_8$	1.07E-03	1.63E-03	2.07E-03	2.89E-02
Aliphatic hydrocarbons $C_9 – C_{18}$	1.3E-02	1.41E-01	7.9E-02	1.03E-00
Aromatic hydrocarbons $C_9 – C_{18}$	6.00E-04	6.95E-04	3.7E-03	2.64E-02
Total Hazard Index	1E-01	2E-01	4E-01	5E+00
Neurological EffectsHazard Index[a]	9E-02	8E-02	3E-01	4E+00
Respiratory Effects Hazard Index[b]	7E-02	2E-01	2E-01	2E+00
Hematogical Effects Hazard Index[c]	3E-02	4E-02	2E-01	3E+00
Developmental Effects Hazard Index[d]	1E-02	3E-02	5E-02	1E+00

Abbreviations: 95%UCL, 95 percent upper confidence limit; HQ, hazard quotient;

[a] Sum of HQs for hydrocarbons with neurological effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3,5-Trimethylbenzene, 1,3-butadiene, benzene, cyclohexane, ethylbenzene, isopropylbenzene, n-hexane, n-nonane, n-pentane, n-propylbenzene, styrene, toluene, xylenes, aliphatic C_5-C_8 hydrocarbons.

[b] Sum of HQs for hydrocarbons with respiratory effects: 1,2,3-Trimethylbenzene, 1,2,4-Trimethylbenzene, 1,3-butadiene, ethylbenzene, isopropylbenzene, n-nonane, propylene, toluene, xylenes, aliphatic C_9-C_{18} hydrocarbons, aromatic C_9-C_{18} hydrocarbons

[c] Sum of HQs for hydrocarbons with hematological effects: 1,2,3-trimethylbenzene, 1,2,4-trimethylbenzene, 1,3,5-trimethylbenzene, benzene

[d] Sum of HQs for hydrocarbons with developmental effects: benzene, cyclohexane, toluene, and xylenes

Table 6: Excess cancer risks for residents living > ½ mile from wells and residents living ≤ ½ mile from wells

	WOE				> ½ mile		≤ ½ mile	
Hydrocarbon	IRIS	IARC	Unit Risk $(\mu g/m^3)$	Source	Cancer risk based on median concentration	Cancer risk based on 95% UCL of mean concentration	Cancer risk based on median concentration	Cancer risk based on 95% UCL of mean concentration
1,3-Butadiene	B2	1	3.00E-05	IRIS	1.30E-06	5.73E-07	1.30E-06	6.54E-07
Benzene	A	1	7.80E-06	IRIS	3.03E-06	5.40E-06	3.33E-06	8.74E-06
Ethylbenzene	NC	2B	2.50E-06	CalEPA	1.75E-07	4.26E-07	2.09E-07	3.48E-06
Styrene	NC	2B	5.00E-07	CEP	3.10E-08	2.70E-08	3.00E-08	9.30E-08
Cumulative cancer risk					5E-06	6-06	5E-06	1E-05

Abbreviations: 95%UCL, 95 percent upper confidence limit; CalEPA, California Environmental Protection Agency; CEP, (Cadwell et al. 1998); IARC, International Agency for Research on Cancer; IRIS, Integrated Risk Information System; Max, maximum; NC, not calculated; WOE, weight of evidence; $\mu g/m^3$, micrograms per cubic meter. Data from CalEPA 2011; IRIS (US EPA 2011).

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0505; FRL–9448–6]

RIN 2060–AP76

Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action announces how the EPA proposes to address the reviews of the new source performance standards for volatile organic compound and sulfur dioxide emissions from natural gas processing plants. We are proposing to add to the source category list any oil and gas operation not covered by the current listing. This action also includes proposed amendments to the existing new source performance standards for volatile organic compounds from natural gas processing plants and proposed standards for operations that are not covered by the existing new source performance standards. In addition, this action proposes how the EPA will address the residual risk and technology review conducted for the oil and natural gas production and natural gas transmission and storage national emission standards for hazardous air pollutants. This action further proposes standards for emission sources within these two source categories that are not currently addressed, as well as amendments to improve aspects of these national emission standards for hazardous air pollutants related to applicability and implementation. Finally, this action addresses provisions in these new source performance standards and national emission standards for hazardous air pollutants related to emissions during periods of startup, shutdown and malfunction.

DATES: Comments must be received on or before October 24, 2011.

Public Hearing. Three public hearings will be held to provide the public an opportunity to provide comments on this proposed rulemaking. One will be held in the Dallas, Texas area, one in Pittsburgh, Pennsylvania, and one in Denver, Colorado, on dates to be announced in a separate document. Each hearing will convene at 10 a.m. local time. For additional information on the public hearings and requesting to speak, see the **SUPPLEMENTARY INFORMATION** section of this preamble.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov:* Follow the instructions for submitting comments.
- *Agency Web site: http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the Air and Radiation Docket Web site.
- *E-mail: a-and-r-docket@epa.gov.* Include Docket ID Number EPA–HQ–OAR–2010–0505 in the subject line of the message.
- *Facsimile:* (202) 566–9744.
- *Mail:* Attention Docket ID Number EPA–HQ–OAR–2010–0505, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for the EPA, 725 17th Street, NW., Washington, DC 20503.
- *Hand Delivery:* United States Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004, Attention Docket ID Number EPA–HQ–OAR–2010–0505. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to the EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* For additional instructions on submitting comments, go to section II.C of the **SUPPLEMENTARY INFORMATION** section of this preamble.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Bruce Moore, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 685–3200; e-mail address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION:

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Preamble Acronyms and Abbreviations

Several acronyms and terms used to describe industrial processes, data inventories and risk modeling are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ACGIH	American Conference of Governmental Industrial Hygienists
ADAF	Age-Dependent Adjustment Factors
AEGL	Acute Exposure Guideline Levels
AERMOD	The air dispersion model used by the HEM–3 model
API	American Petroleum Institute
BACT	Best Available Control Technology
BID	Background Information Document
BPD	Barrels Per Day
BSER	Best System of Emission Reduction
BTEX	Benzene, Ethylbenzene, Toluene and Xylene
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
CBI	Confidential Business Information
CEM	Continuous Emissions Monitoring
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CIIT	Chemical Industry Institute of Toxicology
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DOE	Department of Energy
ECHO	Enforcement and Compliance History Online
e-GGRT	Electronic Greenhouse Gas Reporting Tool
EJ	Environmental Justice
EPA	Environmental Protection Agency
ERPG	Emergency Response Planning Guidelines
ERT	Electronic Reporting Tool
GCG	Gas Condensate Glycol
GHG	Greenhouse Gas
GOR	Gas to Oil Ratio
GWP	Global Warming Potential
HAP	Hazardous Air Pollutants
HEM–3	Human Exposure Model, version 3
HI	Hazard Index
HP	Horsepower
HQ	Hazard Quotient
H_2S	Hydrogen Sulfide
ICR	Information Collection Request
IPCC	Intergovernmental Panel on Climate Change
IRIS	Integrated Risk Information System
km	Kilometer
kW	Kilowatts
LAER	Lowest Achievable Emission Rate
lb	Pounds
LDAR	Leak Detection and Repair
MACT	Maximum Achievable Control Technology
MACT	Code Code within the NEI used to identify processes included in a source category
Mcf	Thousand Cubic Feet
Mg/yr	Megagrams per year
MIR	Maximum Individual Risk
MIRR	Monitoring, Inspection, Recordkeeping and Reporting
$MMtCO_2e$	Million Metric Tons of Carbon Dioxide Equivalents
NAAQS	National Ambient Air Quality Standards
NAC/AEGL	National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances
NAICS	North American Industry Classification System
NAS	National Academy of Sciences
NATA	National Air Toxics Assessment
NEI	National Emissions Inventory
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NIOSH	National Institutes for Occupational Safety and Health
NO_X	Oxides of Nitrogen
NRC	National Research Council
NSPS	New Source Performance Standards
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget
PB–HAP	Hazardous air pollutants known to be persistent and bio-accumulative in the environment
PFE	Potential for Flash Emissions
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter (2.5 microns and less)
POM	Polycyclic Organic Matter
PPM	Parts Per Million
PPMV	Parts Per Million by Volume
PSIG	Pounds per square inch gauge
PTE	Potential to Emit
QA	Quality Assurance
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
REC	Reduced Emissions Completions
REL	CalEPA Reference Exposure Level
RFA	Regulatory Flexibility Act
RfC	Reference Concentration
RfD	Reference Dose
RIA	Regulatory Impact Analysis
RICE	Reciprocating Internal Combustion Engines
RTR	Residual Risk and Technology Review
SAB	Science Advisory Board
SBREFA	Small Business Regulatory Enforcement Fairness Act
SCC	Source Classification Codes
SCFH	Standard Cubic Feet Per Hour
SCFM	Standard Cubic Feet Per Minute
SCM	Standard Cubic Meters
SCMD	Standard Cubic Meters Per Day
SCOT	Shell Claus Offgas Treatment
SIP	State Implementation Plan
SISNOSE	Significant Economic Impact on a Substantial Number of Small Entities
S/L/T	State and Local and Tribal Agencies
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown and Malfunction
STEL	Short-term Exposure Limit
TLV	Threshold Limit Value
TOSHI	Target Organ-Specific Hazard Index
TPY	Tons per Year
TRIM	Total Risk Integrated Modeling System
TRIM.FaTE	A spatially explicit, compartmental mass balance model that

describes the movement and transformation of pollutants over time, through a user-defined, bounded system that includes both biotic and abiotic compartments
TSD Technical Support Document
UF Uncertainty Factor
UMRA Unfunded Mandates Reform Act
URE Unit Risk Estimate
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Does this action apply to me?

The regulated industrial source categories that are the subject of this proposal are listed in Table 1 of this preamble. These standards and any changes considered in this rulemaking would be directly applicable to sources as a Federal program. Thus, Federal, state, local and tribal government entities are not affected by this proposed action.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Category	NAICS code[1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in the regulations. If you have any questions regarding the applicability of this action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this proposal will also be available on the EPA's Web site. Following signature by the EPA Administrator, a copy of this proposed action will be posted on the EPA's Web site at the following address: *http://www.epa.gov/airquality/oilandgas.*

Additional information is available on the EPA's Residual Risk and Technology Review (RTR) Web site at *http://www.epa.gov/ttn/atw/rrisk/oarpg.html.* This information includes the most recent version of the rule, source category descriptions, detailed emissions and other data that were used as inputs to the risk assessments.

C. What should I consider as I prepare my comments for the EPA?

Submitting CBI. Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD ROM that you mail to the EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. If you submit a CD ROM or disk that does not contain CBI, mark the outside of the disk or CD ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, Attention Docket ID Number EPA–HQ–OAR–2010–0505.

D. When will a public hearing occur?

We will hold three public hearings, one in the Dallas, Texas area, one in Pittsburgh, Pennsylvania, and one in Denver, Colorado. If you are interested in attending or speaking at one of the public hearings, contact Ms. Joan Rogers at (919) 541–4487 by September 6, 2011. Details on the public hearings will be provided in a separate notice and we will specify the time and date of the public hearings on *http://www.epa.gov/airquality/oilandgas.* If no one requests to speak at one of the public hearings by September 6, 2011, then that public hearing will be cancelled without further notice.

III. Background Information

A. What are standards of performance and NSPS?

1. What is the statutory authority for standards of performance and NSPS?

Section 111 of the Clean Air Act (CAA) requires the EPA Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the ''best system of emission reduction'' (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' In this notice, we refer to this level of control as the BSER. In determining BSER, we typically conduct a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. Next, for each control system identified, we evaluate its costs, secondary air benefits (or disbenefits) resulting from energy requirements and nonair quality impacts such as solid waste generation. Based on our evaluation, we would determine BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (*i.e.,* a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, an NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

2. What is the regulatory history regarding performance standards for the oil and natural gas sector?

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations.

B. What are NESHAP?

1. What is the statutory authority for NESHAP?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, after the EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) of the CAA calls for us to promulgate national emission standards for hazardous air pollutants (NESHAP) for those sources. ''Major sources'' are those that emit or have the potential to emit (PTE) 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. For major sources, these technology-based standards must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements and nonair quality health and environmental impacts) and are commonly referred to as maximum achievable control technology (MACT) standards.

MACT standards are to reflect application of measures, processes, methods, systems or techniques, including, but not limited to, measures which, (1) reduce the volume of or eliminate pollutants through process changes, substitution of materials or other modifications, (2) enclose systems or processes to eliminate emissions, (3) capture or treat pollutants when released from a process, stack, storage or fugitive emissions point, (4) are design, equipment, work practice or operational standards (including requirements for operator training or certification) or (5) are a combination of the above. CAA section 112(d)(2)(A)–(E). The MACT standard may take the form of a design, equipment, work practice or operational standard where the EPA first determines either that, (1) a pollutant cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant or that any requirement for or use of such a conveyance would be inconsistent with law or (2) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations. CAA sections 112(h)(1)–(2).

The MACT ''floor'' is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3), and may not be based on cost considerations. For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. The MACT floors for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any nonair quality health and environmental impacts and energy requirements.

The EPA is then required to review these technology-based standards and to revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years, under CAA section 112(d)(6). In conducting this review, the EPA is not obliged to completely recalculate the prior MACT determination. *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008).

The second stage in standard-setting focuses on reducing any remaining ''residual'' risk according to CAA section 112(f). This provision requires, first, that the EPA prepare a *Report to Congress* discussing (among other things) methods of calculating risk posed (or potentially posed) by sources after implementation of the MACT standards, the public health significance of those risks, and the EPA's recommendations as to legislation regarding such remaining risk. The EPA prepared and submitted this report (*Residual Risk Report to Congress,* EPA–453/R–99–001) in March 1999. Congress did not act in response to the report, thereby triggering the EPA's obligation under CAA section 112(f)(2) to analyze and address residual risk.

CAA section 112(f)(2) requires us to determine for source categories subject to MACT standards, whether the emissions standards provide an ample margin of safety to protect public health. If the MACT standards for HAP ''classified as a known, probable, or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than 1-in-1 million,'' the EPA must promulgate residual risk standards for the source category (or subcategory), as necessary, to provide an ample margin of safety to protect public health. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. *NRDC* v. *EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008). (''If EPA determines that the existing technology-based standards provide an ''ample margin of safety,'' then the Agency is free to readopt those standards during the residual risk rulemaking.'') The EPA must also adopt more stringent standards, if necessary, to prevent an adverse environmental effect,[1] but must consider cost, energy, safety and other relevant factors in doing so.

Section 112(f)(2) of the CAA expressly preserves our use of a two-step process for developing standards to address any residual risk and our interpretation of ''ample margin of safety'' developed in the *National Emission Standards for Hazardous Air Pollutants: Benzene Emissions from Maleic Anhydride Plants, Ethylbenzene/Styrene Plants, Benzene Storage Vessels, Benzene Equipment Leaks, and Coke By-Product Recovery Plants (Benzene NESHAP)* (54 FR 38044, September 14, 1989). The first step in this process is the determination of acceptable risk. The second step provides for an ample margin of safety to protect public health, which is the level at which the standards are set (unless a more stringent standard is required to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect).

The terms ''individual most exposed,'' ''acceptable level,'' and ''ample margin of safety'' are not specifically defined in the CAA. However, CAA section 112(f)(2)(B) preserves the interpretation set out in the Benzene NESHAP, and the United States Court of Appeals for the District of Columbia Circuit in *NRDC* v. *EPA,* 529 F.3d 1077, concluded that the EPA's interpretation of subsection 112(f)(2) is a reasonable one. See *NRDC* v. *EPA,* 529 F.3d at 1083 (D.C. Cir., ''[S]ubsection 112(f)(2)(B) expressly incorporates EPA's interpretation of the Clean Air Act from the Benzene standard, complete with a citation to the **Federal Register**''). (D.C. Cir. 2008). See also, *A Legislative History of the Clean Air Act Amendments of 1990,* volume 1, p. 877 (Senate debate on Conference Report). We notified Congress in the *Residual Risk Report to Congress* that we intended to use the Benzene NESHAP approach in making CAA section 112(f) residual risk determinations (EPA–453/R–99–001, p. ES–11).

In the Benzene NESHAP, we stated as an overall objective:

> * * * in protecting public health with an ample margin of safety, we strive to provide maximum feasible protection against risks to health from hazardous air pollutants by, (1) protecting the greatest number of persons possible to an individual lifetime risk level no higher than approximately 1-in-1 million; and (2) limiting to no higher than approximately 1-in-10 thousand [*i.e.,* 100-in-1 million] the estimated risk that a person living near a facility would have if he or she were exposed to the maximum pollutant concentrations for 70 years.

The Agency also stated that, ''The EPA also considers incidence (the number of persons estimated to suffer cancer or other serious health effects as a result of exposure to a pollutant) to be an important measure of the health risk to the exposed population. Incidence measures the extent of health risk to the exposed population as a whole, by providing an estimate of the occurrence of cancer or other serious health effects in the exposed population.'' The Agency went on to conclude that ''estimated incidence would be weighed along with other health risk information in judging acceptability.'' As explained more fully in our *Residual Risk Report to Congress,* the EPA does not define ''rigid line[s] of acceptability,'' but considers rather broad objectives to be weighed with a series of other health measures and factors (EPA–453/R–99–001, p. ES–11). The determination of what represents an ''acceptable'' risk is based on a judgment of ''what risks are acceptable in the world in which we live'' (*Residual Risk Report to Congress,* p. 178, quoting the Vinyl Chloride decision at 824 F.2d 1165) recognizing that our world is not risk-free.

In the Benzene NESHAP, we stated that ''EPA will generally presume that if the risk to [the maximum exposed] individual is no higher than approximately 1-in-10 thousand, that risk level is considered acceptable.'' 54 FR 38045. We discussed the maximum individual lifetime cancer risk (or maximum individual risk (MIR)) as being ''the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years.'' *Id.* We explained that this measure of risk ''is an estimate of the upper bound of risk based on conservative assumptions, such as continuous exposure for 24 hours per day for 70 years.'' *Id.* We acknowledge that maximum individual lifetime cancer risk ''does not necessarily reflect the true risk, but displays a conservative risk level which is an upper-bound that is unlikely to be exceeded.'' *Id.*

Understanding that there are both benefits and limitations to using maximum individual lifetime cancer risk as a metric for determining acceptability, we acknowledged in the 1989 Benzene NESHAP that ''consideration of maximum individual risk * * * must take into account the strengths and weaknesses of this measure of risk.'' *Id.* Consequently, the presumptive risk level of 100-in-1 million (1-in-10 thousand) provides a benchmark for judging the acceptability of maximum individual lifetime cancer risk, but does not constitute a rigid line for making that determination.

The Agency also explained in the 1989 Benzene NESHAP the following: ''In establishing a presumption for MIR, rather than a rigid line for acceptability, the Agency intends to weigh it with a series of other health measures and factors. These include the overall incidence of cancer or other serious health effects within the exposed population, the numbers of persons exposed within each individual lifetime risk range and associated incidence within, typically, a 50-kilometer (km) exposure radius around facilities, the science policy assumptions and estimation uncertainties associated with the risk measures, weight of the scientific evidence for human health effects, other quantified or unquantified health effects, effects due to co-location of facilities and co-emission of pollutants.'' *Id.*

In some cases, these health measures and factors taken together may provide a more realistic description of the magnitude of risk in the exposed population than that provided by maximum individual lifetime cancer risk alone. As explained in the Benzene NESHAP, ''[e]ven though the risks judged ''acceptable'' by the EPA in the first step of the Vinyl Chloride inquiry are already low, the second step of the inquiry, determining an ''ample margin of safety,'' again includes consideration of all of the health factors, and whether to reduce the risks even further.'' In the ample margin of safety decision process, the Agency again considers all of the health risks and other health information considered in the first step. Beyond that information, additional factors relating to the appropriate level

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[1] ''Adverse environmental effect'' is defined in CAA section 112(a)(7) as any significant and widespread adverse effect, which may be reasonably anticipated to wildlife, aquatic life or natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental qualities over broad areas.

of control will also be considered, including costs and economic impacts of controls, technological feasibility, uncertainties and any other relevant factors. Considering all of these factors, the Agency will establish the standard at a level that provides an ample margin of safety to protect the public health, as required by CAA section 112(f). 54 FR 38046.

2. How do we consider the risk results in making decisions?

As discussed in the previous section of this preamble, we apply a two-step process for developing standards to address residual risk. In the first step, the EPA determines if risks are acceptable. This determination ''considers all health information, including risk estimation uncertainty, and includes a presumptive limit on maximum individual lifetime [cancer] risk (MIR)[2] of approximately 1-in-10 thousand [*i.e.,* 100-in-1 million].'' 54 FR 38045. In the second step of the process, the EPA sets the standard at a level that provides an ample margin of safety ''in consideration of all health information, including the number of persons at risk levels higher than approximately 1-in-1 million, as well as other relevant factors, including costs and economic impacts, technological feasibility, and other factors relevant to each particular decision.'' *Id.*

In past residual risk determinations, the EPA presented a number of human health risk metrics associated with emissions from the category under review, including: The MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer hazard index (HI); and the maximum acute noncancer hazard. In estimating risks, the EPA considered source categories under review that are located near each other and that affect the same population. The EPA provided estimates of the expected difference in actual emissions from the source category under review and emissions allowed pursuant to the source category MACT standard. The EPA also discussed and considered risk estimation uncertainties. The EPA is providing this same type of information in support of these actions.

The Agency acknowledges that the Benzene NESHAP provides flexibility regarding what factors the EPA might consider in making our determinations and how they might be weighed for each source category. In responding to comment on our policy under the Benzene NESHAP, the EPA explained that: ''The policy chosen by the Administrator permits consideration of multiple measures of health risk. Not only can the MIR figure be considered, but also incidence, the presence of noncancer health effects, and the uncertainties of the risk estimates. In this way, the effect on the most exposed individuals can be reviewed as well as the impact on the general public. These factors can then be weighed in each individual case. This approach complies with the Vinyl Chloride mandate that the Administrator ascertain an acceptable level of risk to the public by employing [her] expertise to assess available data. It also complies with the Congressional intent behind the CAA, which did not exclude the use of any particular measure of public health risk from the EPA's consideration with respect to CAA section 112 regulations, and, thereby, implicitly permits consideration of any and all measures of health risk which the Administrator, in [her] judgment, believes are appropriate to determining what will 'protect the public health.' ''

For example, the level of the MIR is only one factor to be weighed in determining acceptability of risks. The Benzene NESHAP explains ''an MIR of approximately 1-in-10 thousand should ordinarily be the upper end of the range of acceptability. As risks increase above this benchmark, they become presumptively less acceptable under CAA section 112, and would be weighed with the other health risk measures and information in making an overall judgment on acceptability. Or, the Agency may find, in a particular case, that a risk that includes MIR less than the presumptively acceptable level is unacceptable in the light of other health risk factors.'' Similarly, with regard to the ample margin of safety analysis, the Benzene NESHAP states that: ''EPA believes the relative weight of the many factors that can be considered in selecting an ample margin of safety can only be determined for each specific source category. This occurs mainly because technological and economic factors (along with the health-related factors) vary from source category to source category.''

3. What is the regulatory history regarding NESHAP for the oil and natural gas sector?

On July 16, 1992 (57 FR 31576), the EPA published a list of major and area sources for which NESHAP are to be published (*i.e.,* the source category list). Oil and natural gas production facilities were listed as a category of major sources. On February 12, 1998 (63 FR 7155), the EPA amended the source category list to add Natural Gas Transmission and Storage as a major source category.

On June 17, 1999 (64 FR 32610), the EPA promulgated MACT standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage major source categories. The Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH) contains standards for HAP emissions from glycol dehydration process vents, storage vessels and natural gas processing plant equipment leaks. The Natural Gas Transmission and Storage NESHAP (40 CFR part 63, subpart HHH) contains standards for glycol dehydration process vents.

In addition to these NESHAP for major sources, the EPA also promulgated NESHAP for the Oil and Natural Gas Production area source category on January 3, 2007 (72 FR 26). These area source standards, which are based on generally available control technology, are also contained in 40 CFR part 63, subpart HH. This proposed action does not impact these area source standards.

C. What litigation is related to this proposed action?

On January 14, 2009, pursuant to section 304(a)(2) of the CAA, WildEarth Guardians and the San Juan Citizens Alliance filed a Complaint alleging that the EPA failed to meet its obligations under CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) to take actions relative to the review/revision of the NSPS and the NESHAP with respect to the Oil and Natural Gas Production source category. On February 4, 2010, the Court entered a consent decree requiring the EPA to sign by July 28, 2011,[3] proposed standards and/or determinations not to issue standards pursuant to CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) and to take final action by February 28, 2012.

D. What is a sector-based approach?

Sector-based approaches are based on integrated assessments that consider multiple pollutants in a comprehensive and coordinated manner to manage emissions and CAA requirements. One of the many ways we can address sector-based approaches is by reviewing multiple regulatory programs together whenever possible, consistent with all

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[2] Although defined as ''maximum individual risk,'' MIR refers only to cancer risk. MIR, one metric for assessing cancer risk, is the estimated risk were an individual exposed to the maximum level of a pollutant for a lifetime.

[3] On April 27, 2011, pursuant to paragraph 10(a) of the Consent Decree, the parties filed with the Court a written stipulation that changes the proposal date from January 31, 2011, to July 28, 2011, and the final action date from November 30, 2011, to February 28, 2012.

applicable legal requirements. This approach essentially expands the technical analyses on costs and benefits of particular technologies, to consider the interactions of rules that regulate sources. The benefit of multi-pollutant and sector-based analyses and approaches includes the ability to identify optimum strategies, considering feasibility, cost impacts and benefits across the different pollutant types while streamlining administrative and compliance complexities and reducing conflicting and redundant requirements, resulting in added certainty and easier implementation of control strategies for the sector under consideration. In order to benefit from a sector-based approach for the oil and gas industry, the EPA analyzed how the NSPS and NESHAP under consideration relate to each other and other regulatory requirements currently under review for oil and gas facilities. In this analysis, we looked at how the different control requirements that result from these requirements interact, including the different regulatory deadlines and control equipment requirements that result, the different reporting and recordkeeping requirements and opportunities for states to account for reductions resulting from this rulemaking in their State Implementation Plans (SIP). The requirements analyzed affect criteria pollutant, HAP and methane emissions from oil and natural gas processes and cover the NSPS and NESHAP reviews. As a result of the sector-based approach, this rulemaking will reduce conflicting and redundant requirements. Also, the sector-based approach facilitated the streamlining of monitoring, recordkeeping and reporting requirements, thus, reducing administrative and compliance complexities associated with complying with multiple regulations. In addition, the sector-based approach promotes a comprehensive control strategy that maximizes the co-control of multiple regulated pollutants while obtaining emission reductions as co-benefits.

IV. Oil and Natural Gas Sector

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) Oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and ''Christmas tree'' piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include the well drilling, completion and workover processes and includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the ''pads'' where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have ''associated'' natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. We consider the oil refinery sector separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced ''pipeline quality'' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the ''citygate.'' Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide (H_2S) and sulfur dioxide (SO_2) are emitted from production and processing operations that handle and treat ''sour gas.'' Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

V. Summary of Proposed Decisions and Actions

Pursuant to CAA sections 111(b), 112(d)(2), 112(d)(6) and 112(f), we are proposing to revise the NSPS and NESHAP relative to oil and gas to include the standards and requirements summarized in this section. More details of the rationale for these proposed standards and requirements are provided in sections VI and VII of this preamble. In addition, as part of these rationale discussions, we solicit public comment and data relevant to several issues. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

A. What are the proposed revisions to the NSPS?

We reviewed the two NSPS that apply to the oil and natural gas industry. Based on our review, we believe that the requirements at 40 CFR part 60, subpart KKK, should be updated to reflect requirements in 40 CFR part 60, subpart VVa for controlling VOC equipment leaks at processing plants. We also believe that the requirements at 40 CFR part 60, subpart LLL, for controlling SO_2 emissions from natural gas processing plants should be strengthened for facilities with the highest sulfur feed rates and the highest H_2S concentrations. For a more detailed discussion, please see section VI.B.1 of this preamble.

In addition, there are significant VOC emissions from oil and natural gas operations that are not covered by the two existing NSPS, including other emissions at processing plants and emissions from upstream production, as well as transmission and storage facilities. In the 1984 notice that listed source categories (including Oil and Natural Gas) for promulgation of NSPS, we noted that there were discrepancies between the source category names on the list and those in the background document, and we clarified our intent to address all sources under an industry heading at the same time. See 44 FR 49222, 49224–49225.[4] We, therefore, believe that the currently listed Oil and Natural Gas source category covers all operations in this industry (*i.e.,* production, processing, transmission, storage and distribution). To the extent there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category, pursuant to CAA section 111(b), we hereby modify the category list to include all operations in the oil and natural gas sector. Section 111(b) of the CAA gives the EPA broad authority and discretion to list and establish NSPS for a category that, in the Administrator's judgment, causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Pursuant to CAA section 111(b), we are modifying the source category list to include any oil and gas operation not covered by the current listing and evaluating emissions from all oil and gas operations at the same time.

We are also proposing standards for several new oil and natural gas affected facilities. The proposed standards would apply to affected facilities that commence construction, reconstruction or modification after August 23, 2011. These standards, which include requirements for VOC, would be contained in a new subpart, 40 CFR part 60, subpart OOOO. Subpart OOOO would incorporate 40 CFR part 60, subpart KKK and 40 CFR part 60, subpart LLL, thereby having in this one subpart, all standards that are applicable to the new and modified affected facilities described above. We also propose to amend the title of subparts KKK and LLL, accordingly, to apply only to affected facilities already subject to those subparts. Those operations would not become subject to subpart OOOO unless they triggered applicability based on new or modified affected facilities under subpart OOOO.

We are proposing operational standards for completions of hydraulically fractured gas wells. Based on our review, we identified two subcategories of fractured gas wells for which well completions are conducted. For non-exploratory and non-delineation wells, the proposed operational standards would require reduced emission completion (REC), commonly referred to as ''green completion,'' in combination with pit-flaring of gas not suitable for entering the gathering line. For exploratory and delineation wells (these wells generally are not in close proximity to a gathering line), we proposed an operational standard that would require pit flaring. Well completions subject to the standards would be limited to gas well completions following hydraulic fracturing operations. These completions include those conducted at newly drilled and fractured wells, as well as completions conducted following refracturing operations at various times over the life of the well. We have determined that a completion associated with refracturing performed at an existing well (*i.e.,* a well existing prior to August 23, 2011) is considered a modification under CAA section 111(a), because physical change occurs to the existing well resulting in emissions increase during the refracturing and completion operation. A detailed discussion of this determination is presented in the Technical Support Document (TSD) in the docket. Therefore, the proposed standards would apply to completions at new gas wells that are fractured or

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[4] The Notice further states that ''The Administrator may also concurrently develop standards for sources which are not on the priority list.'' 44 FR at 49225.

refractured along with completions associated with fracturing or refracturing of existing gas wells. The modification determination and resultant applicability of NSPS to the completion operation following fracturing or refracturing of existing gas wells (*i.e.,* wells existing before August 23, 2011 would be limited strictly to the wellhead, well bore, casing and tubing, and any conveyance through which gas is vented to the atmosphere and not be extended beyond the wellhead to other ancillary components that may be at the well site such as existing storage vessels, process vessels, separators, dehydrators or any other components or apparatus.

We are also proposing VOC standards to reduce emissions from gas-driven pneumatic devices. We are proposing that each pneumatic device is an affected facility. Accordingly, the proposed standards would apply to each newly installed pneumatic device (including replacement of an existing device). At gas processing plants, we are proposing a zero emission limit for each individual pneumatic controller. The proposed emission standards would reflect the emission level achievable from the use of non-gas-driven pneumatic controllers. At other locations, we are proposing a bleed limit of 6 standard cubic feet of gas per hour for an individual pneumatic controller, which would reflect the emission level achievable from the use of low bleed gas-driven pneumatic controllers. In both cases, the standards provide exemptions for certain applications based on functional considerations.

In addition, the proposed rule would require measures to reduce VOC emissions from centrifugal and reciprocating compressors. As explained in more detail below in section VI.B.4, we are proposing equipment standards for centrifugal compressors. The proposed standards would require the use of dry seal systems. However, we are aware that some owners and operators may need to use centrifugal compressors with wet seals, and we are soliciting comment on the suitability of a compliance option allowing the use of wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device as an acceptable alternative to installing dry seals.

Our review of reciprocating compressors found that piston rod packing wear produces fugitive emissions that cannot be captured and conveyed to a control device. As a result, we are proposing operational standards for reciprocating compressors, such that the proposed rule would require replacement of the rod packing based on hours of usage. The owner or operator of a reciprocating compressor affected facility would be required to monitor the duration (in hours) that the compressor is operated. When the hours of operation reaches 26,000 hours, the owner or operator would be required to change the rod packing immediately. However, to avoid unscheduled shutdowns when 26,000 hours is reached, owners and operators could track hours of operation such that packing replacement could be coordinated with planned maintenance shutdowns before hours of operation reached 26,000. Some operators may prefer to replace the rod packing on a fixed schedule to ensure that the hours of operation would not reach 26,000 hours. We solicit comment on the appropriateness of a fixed replacement frequency and other considerations that would be associated with regular replacement.

We are also proposing VOC standards for new or modified storage vessels. The proposed rule, which would apply to individual vessels, would require that vessels meeting certain specifications achieve at least 95-percent reduction in VOC emissions. Requirements would apply to vessels with a throughput of 1 barrel of condensate per day or 20 barrels of crude oil per day. These thresholds are equivalent to VOC emissions of about 6 tpy.

For gas processing plants, we are updating the requirements for leak detection and repair (LDAR) to reflect procedures and leak thresholds established by 40 CFR 60, subpart VVa. The existing NSPS requires 40 CFR part 60, subpart VV procedures and thresholds.

For 40 CFR part 60, subpart LLL, which regulates SO_2 emissions from natural gas processing plants, we determined that affected facilities with sulfur feed rate of at least 5 long tons per day or H_2S concentration in the acid gas stream of at least 50 percent can achieve up to 99.9-percent SO_2 control, which is greater than the existing standard. Therefore, we are proposing revision to the performance standards in subpart LLL as a result of this review. For a more detailed discussion of this proposed determination, please see section VI.B.1 of this preamble.

We are proposing to address compliance requirements for periods of startup, shutdown and malfunction (SSM) for 40 CFR part 60, subpart OOOO. The SSM changes are discussed in detail in section VI.B.5 below. In addition, we are proposing to incorporate the requirements in 40 CFR part 60, subpart KKK and 40 CFR part 60, subpart LLL into the new subpart OOOO so that all requirements applicable to the new and modified facilities would be in one subpart. This would simplify and streamline compliance efforts on the part of the oil and natural gas industry and could minimize duplication of notification, recordkeeping and reporting.

B. What are the proposed decisions and actions related to the NESHAP?

This section summarizes the results of our RTR for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories and our proposed decisions concerning these two 1999 NESHAP.

1. Addressing Unregulated Emissions Sources

Pursuant to CAA sections 112(d)(2) and (3), we are proposing MACT standards for subcategories of glycol dehydrators for which standards were not previously developed (hereinafter referred to as the ‘‘small dehydrators’’). In the Oil and Natural Gas Production source category, the subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 0.9 megagrams per year (Mg/yr). In the Natural Gas Transmission and Storage source category, the subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 283,000 scmd or actual average benzene emissions less than 0.9 Mg/yr.

The proposed MACT standards for the subcategory of small dehydrators at oil and gas production facilities would require that existing affected sources meet a unit-specific BTEX limit of 1.10×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and that new affected sources meet a BTEX limit of 4.66×10^{-6} grams BTEX/scm-ppmv. At natural gas transmission and storage affected sources, the proposed MACT standard for the subcategory of small dehydrators would require that existing affected sources meet a unit-specific BTEX emission limit of 6.42×10^{-5} grams BTEX/scm-ppmv and that new affected sources meet a BTEX limit of 1.10×10^{-5} grams BTEX/scm-ppmv.

We are also proposing MACT standards for storage vessels that are currently not regulated under the Oil and Natural Gas Production NESHAP. The current MACT standards apply only to storage vessels with the potential for flash emissions (PFE). As explained in section VII, the original MACT analysis accounted for all storage vessels. We are, therefore, proposing to apply the current MACT standards of 95-percent emission reduction to every storage vessel at major source oil and natural gas production facilities. In conjunction with this change, we are proposing to amend the definition of associated equipment to exclude all storage vessels, and not just those with the PFE, from being considered ''associated equipment.'' This means that emissions from all storage vessels, and not just those from storage vessels with the PFE, are to be included in the major source determination.

2. What are the proposed decisions and actions related to the risk review?

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we find that the current levels of emissions allowed by the MACT reflect acceptable levels of risk; however, the level of emissions allowed by the alternative compliance option for glycol dehydrator MACT (*i.e.,* the option of reducing benzene emissions to less than 0.9 Mg/yr in lieu of the MACT standard of 95-percent control) reflects an unacceptable level of risk. We are, therefore, proposing to eliminate the 0.9 Mg/yr alternative compliance option.

In addition, we are proposing that the MACT for these two oil and gas source categories, as revised per above, provide an ample margin of safety to protect public health and prevent adverse environmental effects.

3. What are the proposed decisions and actions related to the technology reviews of the existing NESHAP?

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we are proposing no revisions to the existing NESHAP pursuant to section 112(d)(6) of the CAA.

4. What other actions are we proposing?

We are proposing an alternative performance test for non-flare, combustion control devices. This test is to be conducted by the combustion control device manufacturer to demonstrate the destruction efficiency achieved by a specific model of combustion control device. This would allow a source to purchase a performance tested device for installation at their site without being required to conduct a site-specific performance test. A definition for ''flare'' is being proposed in the NESHAP to clarify which combustion control devices fall under the manufacturers' performance testing alternative, and to clarify which devices must be performance tested.

We are also proposing to: Revise the parametric monitoring calibration provisions; require periodic performance testing where applicable; remove the allowance of a design analysis for all control devices other than condensers; remove the requirement for a minimum residence time for an enclosed combustion device; and add recordkeeping and reporting requirements to document carbon replacement intervals. These changes are being proposed to bring the NESHAP up-to-date based on what we have learned regarding control devices and compliance since the original promulgation date.

In addition, we are proposing the elimination of the SSM exemption in the Oil and Natural Gas Production and the Natural Gas Transmission and Storage NESHAP. As discussed in more detail below in section VII, consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2010), the EPA is proposing that the established standards in these two NESHAP apply at all times. We are proposing to revise Table 2 to both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH to indicate that certain 40 CFR part 63 general provisions relative to SSM do not apply, including: 40 CFR 63.6 (e)(1)(i)[5] and (ii), 40 CFR 63.6(e)(3) (SSM plan requirement), 40 CFR 63.6(f)(1); 40 CFR 63.7(e)(1), 40 CFR 63.8(c)(1)(i) and (iii), and the last sentence of 40 CFR 63.8(d)(3); 40 CFR 63.10(b)(2)(i),(ii), (iv) and (v); 40 CFR 63.10(c)(10), (11) and (15); and 40 CFR 63.10(d)(5). We are also proposing to: (1) Revise 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i) regarding operation of the control device to be consistent with the SSM compliance requirements; and (2) revise the SSM-associated reporting and recordkeeping requirements in 40 CFR 63.774, 40 CFR 63.775, 40 CFR 63.1284 and 40 CFR 63.1285 to require reporting and recordkeeping for periods of malfunction. In addition, as explained below, we are proposing to add an affirmative defense to civil penalties for exceedances of emission limits caused by malfunctions, as well as criteria for establishing the affirmative defense.

The EPA has attempted to ensure that we have neither overlooked nor failed to propose to remove from the existing text any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption, nor included any such provisions in the proposed new regulatory language. We are specifically seeking comment on whether there are any such provisions that we have inadvertently overlooked or incorporated.

We are also revising the applicability provisions of 40 CFR part 63, subpart HH to clarify requirements regarding PTE determination and the scope of a facility subject to subpart HH. Lastly, we are proposing several editorial corrections and plain language revisions to improve these rules.

C. What are the proposed notification, recordkeeping and reporting requirements for this proposed action?

1. What are the proposed notification, recordkeeping and reporting requirements for the proposed NSPS?

The proposed 40 CFR part 60, subpart OOOO includes new requirements for several operations for which there are no existing Federal standards. Most notably, as discussed in sections V.A and VI.B of this preamble, the proposed NSPS will cover completions and recompletions of hydraulically fractured gas wells. We estimate that over 20,000 completions and recompletions annually will be subject to the proposed requirements. Given the number of these operations, we believe that notification and reporting must be streamlined to the extent possible to minimize undue burden on owners and operators, as well as state, local and tribal agencies. In section V.D of this preamble, we discuss some innovative implementation approaches being considered and seek comment on these and other potential methods of streamlining notification and reporting for well completions covered by the proposed rule.

Owners or operators are required to submit initial notifications and annual reports, and to retain records to assist in documenting that they are complying with the provisions of the NSPS. These notification, recordkeeping and reporting activities include both requirements of the 40 CFR part 60 General Provisions, as well as requirements specific to 40 CFR part 60, subpart OOOO.

Owners or operators of affected facilities (except for pneumatic controller and gas wellhead affected

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[5] 40 CFR 63.6(e)(1)(i) requires owners or operators to act according to the general duty to ''operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.'' This general duty to minimize is included in our proposed standard at 40 CFR 63.783(b)(1).

sources) must submit an initial notification within 1 year after becoming subject to 40 CFR part 60, subpart OOOO or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later. For pneumatic controllers, owners and operators are not required to submit an initial notification, but instead are required to report the installation of these affected facilities in their facility's annual report. Owners or operators of wellhead affected facilities (well completions) would also be required to submit a 30-day advance notification of each well completion subject to the NSPS. In addition, annual reports are due 1 year after initial startup date for your affected facility or 1 year after the date of publication of the final rule in the **Federal Register**, whichever is later. The notification and annual reports must include information on all affected facilities owned or operated that were new, modified or reconstructed sources during the reporting period. A single report may be submitted covering multiple affected facilities, provided that the report contains all the information required by 40 CFR 60.5420(b). This information includes general information on the facility (*i.e.*, company name and address, etc.), as well as information specific to individual affected facilities.

For wellhead affected facilities, this information includes details of each well completion during the period, including duration of periods of gas recovery, flaring and venting. For centrifugal compressor affected facilities, information includes documentation that the compressor is fitted with dry seals. For reciprocating compressors, information includes the cumulative hours of operation of each compressor and records of rod packing replacement.

Information for pneumatic device affected facilities includes location and manufacturer specifications of each pneumatic controller installed during the period and documentation that supports any exemption claimed allowing use of high bleed controllers. For controllers installed at gas processing plants, the owner or operator would document the use of non-gas driven devices. For controllers installed in locations other than at gas processing plants, owners or operators would provide manufacturer's specifications that document bleed rate not exceeding 6 cubic feet per hour.

For storage vessel affected facilities, required report information includes information that documents control device compliance, if applicable. For vessels with throughputs below 1 barrel of condensate per day and 21 barrels of crude oil per day, required information also includes calculations or other documentation of the throughput. For onshore gas processing plants, semi-annual reports are required, and include information on number of pressure relief devices, number of pressure relief devices for which leaks were detected and pressure relief devices for which leaks were not repaired, as required in 40 CFR 60.5396 of subpart OOOO.

Records must be retained for 5 years and generally consist of the same information required in the initial notification and annual and semiannual reports.

2. What are the proposed amendments to notification, recordkeeping and reporting requirements for the NESHAP?

We are proposing to revise certain recordkeeping requirements of 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH. Specifically, we are proposing that facilities using carbon adsorbers as a control device keep records of their carbon replacement schedule and records for each carbon replacement. In addition, owners and operators are required to keep records of the occurrence and duration of each malfunction or operation of the air pollution control equipment and monitoring equipment.

In addition, in conjunction with the proposed MACT standards for small glycol dehydration units and storage vessels that do not have the PFE in the proposed amendment to 40 CFR part 63, subpart HH, we are proposing that owners and operators of affected small glycol dehydration units and storage vessels submit an initial notification within 1 year after becoming subject to subpart HH or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later.

Similarly, in conjunction with the proposed MACT standards for small glycol dehydration units in the proposed 40 CFR part 63, subpart HHH amendments, we are proposing that owners and operators of small glycol dehydration units submit an initial notification within 1 year after becoming subject to subpart HHH or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later. Affected sources under either 40 CFR part 63, subpart HH or subpart HHH that plan to be area sources by the compliance dates will be required to submit a notification describing their schedule for the actions planned to achieve area source status.

The proposed amendments to the NESHAP also include additional requirements for the contents of the periodic reports. For both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, we are proposing that the periodic reports also include periodic test results and information regarding any carbon replacement events that occurred during the reporting period.

3. *How is information submitted using the Electronic Reporting Tool (ERT)?*

Performance test data are an important source of information that the EPA uses in compliance determinations, developing and reviewing standards, emission factor development, annual emission rate determinations and other purposes. In these activities, the EPA has found it ineffective and time consuming, not only for owners and operators, but also for regulatory agencies, to locate, collect and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

Through this proposal, the EPA is taking a step to increase the ease and efficiency of data submittal and improve data accessibility. Specifically, the EPA is proposing that owners and operators of oil and natural gas sector facilities submit electronic copies of required performance test reports to the EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

As proposed above, data entry would be through an electronic emissions test report structure called the *Electronic Reporting Tool* (ERT). The ERT will be able to transmit the electronic report through the EPA's Central Data Exchange network for storage in the WebFIRE database making submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

The proposal to submit performance test data electronically to the EPA would apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at *http://*

www.epa.gov/ttn/chief/ert/ert_tool.html. We believe that industry would benefit from this proposed approach to electronic data submittal. Having these data, the EPA would be able to develop improved emission factors, make fewer information requests, and promulgate better regulations.

One major advantage of the proposed submittal of performance test data through the ERT is a standardized method to compile and store much of the documentation required to be reported by this rule. Another advantage is that the ERT clearly states testing information that would be required. Another important benefit of submitting these data to the EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When the EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. This would result in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and the EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local and tribal agencies could also benefit from more streamlined and accurate review of electronic data submitted to them. The ERT would allow for an electronic review process rather than a manual data assessment making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the proposed data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA would be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, in addition to supporting regulation development, control strategy development and other air pollution control activities having an electronic database populated with performance test data would save industry, state, local, tribal agencies and the EPA significant time, money and effort while also improving the quality of emission inventories and, as a result, air quality regulations.

D. What are the innovative compliance approaches being considered?

Given the potential number and diversity of sources affected by this action, we are exploring optional approaches to provide the regulated community, the regulators and the public a more effective mechanism that maximizes compliance and transparency while minimizing burden.

Under a traditional approach, owners or operators would provide notifications and keep records of information required by the NSPS. In addition, they would certify compliance with the NSPS as part of a required annual report that would include compliance-related information, such as details of each well completion event and information documenting compliance with other requirements of the NSPS. The EPA, state or local agency would then physically inspect the affected facilities and/or audit the records retained by the owner or operator. As an alternative to the traditional approach, we are seeking an innovative way to provide for more transparency to the public and less burden on the regulatory agencies and owners and operators, especially as it relates to modification of existing sources through recompletions of hydraulically fractured gas wells. These innovative approaches would provide compliance assurance in light of the absence of requirements for CAA title V permitting of non-major sources.

Section V.E of this preamble discusses permitting implications associated with the NSPS and presents a proposed rationale for exempting non-major sources subject to the NSPS from title V permitting requirements. As discussed in sections V.A, V.C and VI.B of this preamble, the proposed NSPS will cover completions and recompletions of hydraulically fractured gas wells. We estimate that over 20,000 completions and recompletions annually will be subject to the proposed requirements. As a result, we believe that notification and reporting associated with well completions must be streamlined to the extent possible to minimize undue burden on owners and operators, as well as state, local and tribal agencies. Though the requirements being proposed here are based on the traditional approach to compliance and do not include specific regulatory provisions for innovative compliance tools, we have included discussions below that describe how some of these optional tools could work, and we will consider providing for such options in the final action. Further, we request comments and suggestions on all aspects of the innovative compliance approaches discussed below and how they may be implemented appropriately. We are seeking comment regarding the scope of application of one or more of these approaches, *i.e.,* which provisions of the standards being proposed here would be suitable for specific compliance approaches, and whether the approaches should be alternatives to the requirements in the regulations.

The guiding principles we are following in considering these approaches to compliance are: (1) Simplicity and ease of understanding and implementation; (2) transparency and public accessibility; (3) electronic implementation where appropriate; and (4) encouragement of compliance by making compliance easier than noncompliance. Below are some tools that, when used in tandem with emissions limits and operational standards, the Agency believes could both assure compliance and transparency, while minimizing burden on affected sources and regulatory agencies.

1. Registration of Wells and Advance Notification of Planned Completions

Although the proposed NSPS will not require approval to drill or complete wells, it is important that regulatory agencies know when completions of hydraulically fractured wells are to be performed. Notification should occur sufficiently in advance to allow for inspections or audits to certify or verify that the operator will have in place and use the appropriate controls during the completion. To that end, the proposed NSPS requires a 30-day advance notification of each completion or recompletion of a hydraulically fractured gas well. The advance notification would require that owners or operators provide the anticipated date of the completion, the geographic coordinates of the well and identifying information concerning the owner or operator and responsible company official. We believe this notification requirement serves as the registration requirement and could be streamlined through optional electronic reporting with web-based public access or other methods. We seek comment on potential methodologies that would minimize burden on operators, while providing timely and useful information for regulators and the public. We also solicit comment on provisions for a follow-up notification one or two days before an impending completion via telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance. However, we would expect an owner or operator to provide the follow-up notification only in cases where the completion date was expected to deviate from the original date provided. We ask for suggestions regarding how much advance notification is needed and the most effective method of providing sufficient and accurate advance notification of well completions.

2. Third Party Verification

To complement the annual compliance certification required under the proposed NSPS, we are considering and seeking comment on the potential use of third party verification to assure compliance. Since the emission sources in the oil and natural gas sector, especially well completions, are widely geographically dispersed (often in very remote locations), compliance assurance can be very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers. Additionally, we believe that verification of the data collection, compilation and calculations by an independent and impartial third party could facilitate the demonstration of compliance for the public. Verification of emissions data can also be beneficial to owners and operators by providing certainty of compliance status.

As mentioned above, notification and reporting requirements associated with well completions are likely applications for third party verification used in tandem with the required annual compliance certification. The third party verification program could be used in a variety of ways to ease regulatory burden on the owners and operators and to leverage compliance assurance efforts of the EPA and state, local and tribal agencies. The third party agent could serve as a clearinghouse for notifications, records and annual compliance certifications submitted by owners and operators. This would provide online access to completion information by regulatory agencies and the public. Having notifications submitted to the clearinghouse would relieve state, local and tribal agencies of the burden of receiving thousands of paper or e-mail well completion notifications each year, yet still provide them quick access to the information. Using a third party agent, it is possible that notifications of well completions could be submitted with an advance period much less than 30 days that could make a 2 day follow-up notification unnecessary. The clearinghouse could also house information on past completions and copies of compliance certifications. We seek comment on whether annual reports for well completions would be needed if a suitable third party verification program was in place and already housed that same information. We also solicit comment on the range of potential activities the third party verification program could handle with regard to well completions.

In this proposed action, there are also provisions for applying third party verification to the required electronic reporting using the ERT (see section V.C.3 above for a discussion of the ERT). As stated above, all sources must use the ERT to submit all performance test reports (required in 40 CFR parts 60, 61 and 63) to the EPA. There is an option in the ERT for state, local and tribal agencies to review and verify that the information submitted to the EPA is truthful, accurate and complete. Third party verifiers could be contractors or other personnel familiar with oil and natural gas exploration and production. We are seeking comment on appropriate third party reviewers and qualifications and registration requirements under such a program. We want to state clearly here that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and the EPA.

Potential issues with third party verification include costs incurred by industry and approval of third party verifiers. The cost of third party verification would be borne by the affected industries. We are seeking comment on whether third party verification paid for by industry would result in impartial, accurate and complete data information. The EPA, working with state, local and tribal agencies and industry, would expect to develop guidance for third party verifiers. We are seeking comment on whether or not the EPA should approve third party verifiers.

3. Electronic Reporting Using Existing Mechanisms

The proposed 40 CFR part 60, subpart OOOO and final Greenhouse Gas (GHG) Mandatory Reporting Rule, 40 CFR part 98, subpart W, provide details on flare and vented emission sources and how to estimate their emissions. We solicit comment on requiring sources to electronically submit their emissions data for the oil and gas rules proposed here. The EPA's *Electronic Greenhouse Gas Reporting Tool* (e-GGRT) for 40 CFR part 98, subpart W, while used to report emissions at the emissions source level (*e.g.,* well completions, well unloading, compressors, gas plant leaks, etc.), will aggregate emissions at the basin level for e-reporting purposes. As a result, it may be difficult to merge reporting under NSPS subpart OOOO with GHG Reporting Rule subpart W methane reporting, especially if manual reporting is used. However, since the operator would have these emissions details at the individual well level (because that will be how they would develop their basin-wide estimates), we do not believe it would be a significant burden to require owners or operators to report the data they already have for subpart W in an ERT for NSPS and NESHAP compliance purposes. However, if the e-GGRT is not structured to provide for reporting of other pollutants besides GHG (*e.g.,* VOC and HAP), then there may be some modification of the database required to accommodate the other pollutants.

4. Provisions for Encouraging Innovative Technology

The oil and natural gas industry has a long history of innovation in developing new exploration and production methods, along with techniques to minimize product losses and reduce adverse environmental impacts. These efforts are often undertaken with tremendous amounts of research, including pilot applications at operating facilities in the field. Absent regulation, these developmental activities, some of which ultimately are not successful, can proceed without risk of violation of any standards. However, as more emission sources in this source category are covered by regulation, as in the case of the action being proposed here, there likely will be situations where innovation and development of new control techniques potentially could be stifled by risk of violation.

We believe it is important to facilitate, not hinder, innovation and continued development of new technology that can result in enhanced environmental performance of facilities and sources affected by the EPA's regulations. However, any approaches to accommodate technology development must be designed and implemented in accordance with the CAA and other statutes. We seek comment on approaches that may be suitable for allowing temporary field testing of technology in development. These approaches could include not only established procedures under the CAA and its implementing regulations, but new ways to apply or interpret these provisions to avoid impeding innovation while remaining environmentally responsible and legal.

E. How does the NSPS relate to permitting of sources?

1. How does this action affect permitting requirements?

The proposed rules do not change the Federal requirements for determining whether oil and gas sources are major sources for purposes of nonattainment major New Source Review (NSR), prevention of significant deterioration, CAA title V, or HAP major sources pursuant to CAA section 112. Specifically, if an owner or operator is not currently required to get a major NSR or title V permit for oil and gas sources, including well completions, it would not be required to get a major NSR or title V permit as a result of these proposed standards. EPA-approved state and local major source permitting programs would not be affected. That is, state and local agencies with EPA-approved programs will still make case-by-case major source determinations for purposes of major NSR and title V, relying on the regulatory criteria, as explained in the McCarthy Memo.[6] Consistent with the McCarthy Memo, whether or not a permitting authority should aggregate two or more pollutant-emitting activities into a single major stationary source for purposes of NSR and title V remains a case-by-case decision in which permitting authorities retain the discretion to consider the factors relevant to the specific circumstances of the permitted activities.

In addition, the proposed standards would not change the requirements for determining whether oil and gas sources are subject to minor NSR. Nor would the proposed standards affect existing EPA-approved state and local minor NSR rules, as well as policies and practices implementing those rules. Many state and local agencies have already adopted minor NSR permitting programs that provide for control of emissions from relatively small emission sources, including various pieces of equipment used in oil and gas fields. State and local agencies would be able to continue to use any EPA-approved General Permits, Permits by Rule, and other similar streamlining mechanisms to permit oil and gas sources such as wells. We recently promulgated the final Tribal Minor NSR rules for use in issuing minor issue permits on tribal lands, where many oil and gas sources are located.

The proposed standards will lead to better control of and reduced emissions from oil and gas production, gas processing and transmission and storage, including wells. In some instances, we anticipate that complying with the NSPS would reduce emissions from these smaller sources to below the minor source applicability thresholds. In those cases, sources that would otherwise have been subject to minor NSR would not need to get minor NSR permits as a result of being subject to the NSPS. Accordingly, the number of minor NSR permits, as well as the Agency resources needed to issue them, would be reduced.

We expect the emission reductions achieved from the proposed standards to significantly improve ozone nonattainment problems in areas where oil and gas production occurs. Strategies for attaining and maintaining the national ambient air quality standards (NAAQS) are a function of SIP (or, in some instances, Federal Implementation Plans and Tribal Implementation Plans) pursuant to CAA section 110. In developing plans to attain and maintain the NAAQS, EPA works with state, local or Tribal agencies to account for growth and develop overall control strategies that address existing and expected emissions. The reductions achieved by the standards will make it easier for state and local agencies to plan for and to attain and maintain the ozone NAAQS.

2. How does this action affect applicability of CAA title V?

Under section 502(a) of the CAA, the EPA may exempt one or more non-major sources[7] subject to CAA section 111 (NSPS) standards from the requirements of title V if the EPA finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such sources. The EPA determine whether to exempt a non-major source from title V at the time we issue the relevant CAA section 111 standards (40 CFR 70.3(b)(2)). We are proposing in this action to exempt from the requirements of title V non-major sources that would be subject to the proposed NSPS for well completions, pneumatic devices, compressors, and/or storage vessels. These non-major sources (hereinafter referred to as the ''oil and gas NSPS non-major sources'') would not be required to obtain title V permits solely as a result of being subject to one or more of the proposed NSPS identified above (hereinafter referred to as the ''proposed NSPS''); however, if they were otherwise required to obtain title V permits, such requirement(s) would not be affected by the proposed exemption.

Consistent with the statute, the EPA believes that compliance with title V permitting is ''unnecessarily burdensome'' for the oil and gas NSPS non-major sources. The EPA's inquiry into whether this criterion was satisfied is based primarily upon consideration of the following four factors: (1) Whether title V would result in significant improvements to the compliance requirements that we are proposing for the oil and gas NSPS affected non-major sources; (2) whether title V permitting would impose a significant burden on these non-major sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies; (3) whether the costs of title V permitting for these non-major sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources; and (4) whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed Oil and Natural Gas NSPS without relying on title V permits. Not all of the four factors must weigh in favor of an exemption. See 70 FR 75320, 75323 (Title V Exemption Rule). Instead, the factors are to be considered in combination and the EPA determines whether the factors, taken together, support an exemption from title V for the oil and gas non-major sources. Additionally, consistent with the guidance provided by the legislative history of CAA section 502(a),[8] we considered whether exempting the Oil and Natural Gas NSPS non-major sources would adversely affect public health, welfare or the environment. The first factor is whether title V would result in significant improvements to the compliance requirements in the proposed NSPS. A finding that title V would not result in significant improvements to the compliance requirements in the proposed NSPS would support a conclusion that title V permitting is ''unnecessary'' for non-

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[6] *Withdrawal of Source Determinations for Oil and Gas Industries,* September 22, 2009. This memo continues to articulate the Agency's interpretation for major NSR and title V permitting of oil and gas sources.

[7] CAA section 502(a) prohibits title V exemption for any major source, which is defined in CAA section 501(2) and 40 CFR 70.2.

[8] The legislative history of section 502(a) suggests that EPA should not grant title V exemptions where doing so would adversely affect public health, welfare or the environment. (See Chafee-Baucus Statement of Senate Managers, Environment and Natural Resources Policy Division 1990 CAA Leg. Hist. 905, Compiled November 1993.)

major sources subject to the Oil and Natural Gas Production NSPS.

One way that title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with permit terms and conditions reflecting the emission limitations and control technology requirements imposed in the standard. See 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1). The ''periodic monitoring'' provisions of 40 CFR 70.6(a)(3)(i)(B) and 40 CFR 71.6(a)(3)(i)(B) require new monitoring to be added to the permit when the underlying standard does not already require ''periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring).'' In addition, title V imposes a number of recordkeeping and reporting requirements that may be important for assuring compliance. These include requirements for a monitoring report at least every 6 months, prompt reports of deviations, and an annual compliance certification. See 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3), 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1), and 40 CFR 70.6(c)(5) and 40 CFR 71.6(c)(5). To determine whether title V permits would add significant compliance requirements to the proposed NSPS, we compared the title V monitoring, recordkeeping and reporting requirements mentioned above to those requirements proposed for the Oil and Natural Gas NSPS affected facilities.

For wellhead affected facilities (well completions), the proposed NSPS would require (1) 30-day advance notification of each well completion to be performed; (2) noninstrumental monitoring, which is achieved through documentation and recordkeeping of procedures followed during each completion, including total duration of the completion event, amount of time gas is recovered using reduced emission completion techniques, amount of time gas is combusted, amount of time gas is vented to the atmosphere and justification for periods when gas is combusted or vented rather than being recovered; (3) reports of cases where well completions were not performed in compliance with the NSPS; (4) annual reports that document all completions performed during the reporting period (a single report may be used to document multiple completions conducted by a single owner or operator during the reporting period); and (5) annual compliance certifications submitted with the annual report.

These monitoring, recordkeeping and reporting requirements in the proposed NSPS for well completions are sufficient to ensure that the Administrator, the state, local and tribal agencies and the public are aware of completion events before they are performed to provide opportunity for inspection. Sufficient documentation would also be required to be retained and reported to the Administrator to assure compliance with the NSPS for well completions. In light of the above, we have determined that additional monitoring through title V is not needed and that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed requirements for well completions.

With respect to storage vessels, the proposed NSPS would require 95-percent control of VOC emissions. The proposed standard could be met by a vapor recovery unit, a flare control device or other control device. The proposed NSPS would require an initial performance test followed by continuous monitoring of the control device used to meet the 95-percent control. We believe that the monitoring requirements described above are sufficient to assure compliance with the proposed NSPS for storage vessels and, therefore, additional monitoring through title V is not needed. In addition to monitoring, as part of the first factor, we have considered the extent to which title V could potentially enhance compliance through recordkeeping or reporting requirements. The proposed NSPS would require (1) construction, startup and modification notifications, as required by 40 CFR 60.7(a); and (2) annual reports that identify all storage vessel affected facilities of the owner or operator and documentation of periods of non-compliance. The proposed NSPS would also require records documenting liquid throughput of condensate or crude oil (to determine applicability), as provided for in the proposed rule. Recordkeeping would also include records of the initial performance test and other information that document compliance with applicable emission limit. These requirements are similar to those under title V. In light of the above, we believe that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed NSPS for storage vessels.

For pneumatic controllers, centrifugal compressors and reciprocating compressors, the proposed NSPS are in the form of operational, work practice or equipment standards.[9] For each of these affected facilities, the proposed NSPS would require: (1) Construction, startup and modification notifications, as required by 40 CFR 60.7(a); (2) annual reports; (3) for each pneumatic controller installed or modified (including replacement of an existing controller), records of location and date of installation and documentation that each controller emits no more than the applicable emission limit or is exempt (with rationale for the exemption); (4) for each centrifugal compressor, records that document that each new or modified compressor is equipped with dry seals; and (5) for each new or modified reciprocating compressor, records of rod packing replacement, including elapsed operating hours since the previous rod packing installation.

For these other affected sources described above, the proposed NSPS provide monitoring in the form of recordkeeping (as described above) that would assure compliance with the proposed operational, work practice or equipment standards. Monitoring by means other than recordkeeping would not be practical or appropriate for these standards. Records are required to ensure that these standards and practices are followed. We believe that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed NSPS for pneumatic controllers and compressors.

We acknowledge that title V might provide for additional compliance requirements for these non-major sources, but we have determined, as explained above, that the monitoring, recordkeeping and reporting requirements in this proposed NSPS are sufficient to assure compliance with the proposed standards for well completions, storage vessels, pneumatic controllers and compressors. Further, given the nature of some of the operations and the types of the requirements at issue, the additional compliance requirements under title V would not significantly improve the compliance requirements in this proposed NSPS. For instance, well completions occur over a very short period (generally 3 to 10 days), and the proposed NSPS for pneumatic controllers and centrifugal compressors can be met by simply installing the equipment that meet the proposed emission limit; therefore, the semi-annual reporting requirement under title V would not improve compliance with

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[9] The proposed numeric standards for pneumatic controllers reflect the use of specific equipment (either non-gas driven device or low-bleed device).

these proposed NSPS and, in fact, may seem inappropriate for such short term operations.

For the reasons stated above, we believe that title V would not result in significant improvements to the compliance requirements that are provided in this proposed NSPS. Therefore, the first factor supports a conclusion that title V permitting is ''unnecessary'' for non-major sources subject to the Oil and Natural Gas NSPS.

The second factor we considered is whether title V permitting would impose significant burdens on the oil and natural gas NSPS non-major sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies. Subjecting any source to title V permitting imposes certain burdens and costs that do not exist outside of the title V program. EPA estimated that the average cost of obtaining and complying with a title V permit was $65,700 per source for a 5-year permit period, including fees. See Information Collection Request (ICR) for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07. EPA does not have specific estimates for the burdens and costs of permitting the oil and gas NSPS non-major sources; however, there are certain activities associated with the 40 CFR part 70 and 40 CFR part 71 rules. These activities are mandatory and impose burdens on any facility subject to title V. They include reading and understanding permit program regulations; obtaining and understanding permit application forms; answering follow-up questions from permitting authorities after the application is submitted; reviewing and understanding the permit; collecting records; preparing and submitting monitoring reports; preparing and submitting prompt deviation reports, as defined by the state, which may include a combination of written, verbal and other communication methods; collecting information, preparing and submitting the annual compliance certification; preparing applications for permit revisions every 5 years; and, as needed, preparing and submitting applications for permit revisions. In addition, although not required by the permit rules, many sources obtain the contractual services of consultants to help them understand and meet the permitting program's requirements. The ICR for 40 CFR part 70 provides additional information on the overall burdens and costs, as well as the relative burdens of each activity described here. Also, for a more comprehensive list of requirements imposed on 40 CFR part 70 sources (hence, burden on sources), see the requirements of 40 CFR 70.3, 40 CFR 70.5, 40 CFR 70.6, and 40 CFR 70.7. The activities described above, which are quite extensive and time consuming, would be a significant burden on the non-major sources that would be subject to the proposed NSPS, in particular for well completion and/or pneumatic devices, considering the short duration of a well completion and the one time equipment installation of a pneumatic controller for meeting the proposed NSPS. Furthermore, some of the non-major sources that would be subject to the proposed NSPS may be small entities that may lack the technical resources and, therefore, need assistance from the permitting authorities to comply with the title V permitting requirements. Based on our projections, over 20,000 well completions (for both new hydraulically fractured gas wells and for existing gas wells that are subsequently fractured or re-fractured) will be performed each year. For pneumatic controller affected facilities, we estimate that approximately 14,000 new controllers would be subject to the NSPS each year. Our estimated numbers of affected facilities that would be subject to the proposed NSPS for storage vessels and compressors are smaller (around 500 compressors and 300 storage vessels). Although we do not know the total number of non-major sources that would be subject to the proposed NSPS, based on the estimated numbers of affected facilities, we anticipate a significant increase in the number of permit applications that permitting authorities would have to process each year. This significant burden on the permitting authorities raises a concern with the potential difficulty or delay that the small entities may face in obtaining sufficient assistance from the permitting authorities.

The third factor we considered is whether the costs of title V permitting for these area sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources. We concluded, in considering the first factor, that the monitoring, recordkeeping and reporting requirements in this proposed NSPS assure compliance with the proposed standards, that title V would not result in significant improvement to these compliance requirements and, that, in some instances, certain title V compliance requirements may not be appropriate. In addition, as discussed above in our consideration of the second factor, we have concerns with the potential burdens that title V may impose on these sources. In addition, below in our consideration of the fourth factor, we find that there are adequate implementation and enforcement programs in place to assure compliance with the proposed NSPS. In light of the above, we find that the costs of title V permitting are not justified for the sources we propose to exempt. Accordingly, the third factor supports title V exemption for the oil and gas NSPS non-major sources.

The fourth factor we considered is whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed NSPS for oil and gas sources without relying on title V permits. The CAA provides States the opportunity to take delegation of NSPS. Before the EPA will delegate the program, the EPA will evaluate the state programs to ensure that states have adequate capability to enforce the CAA section 111 regulations and provide assurances that they will enforce the NSPS. In addition, EPA retains authority to enforce this NSPS anytime under CAA sections 111, 113 and 114. Accordingly, we can enforce the monitoring, recordkeeping and reporting requirements, which, as discussed under the first factor, are adequate to assure compliance with this NSPS. Also, states and the EPA often conduct voluntary compliance assistance, outreach and education programs (compliance assistance programs), which are not required by statute. We determined that these additional programs will supplement and enhance the success of compliance with these proposed standards. We believe that the statutory requirements for implementation and enforcement of this NSPS by the delegated states, the EPA and the additional assistance programs described above together are sufficient to assure compliance with these proposed standards without relying on title V permitting.

Our balance of the four factors strongly supports a finding that title V is unnecessarily burdensome for the oil and gas non-major sources. While title V might add additional compliance requirements if imposed, we believe that there would not be significant improvements to the compliance requirements in this proposed rule because the proposed rule requirements are specifically designed to assure compliance with the proposed NSPS and, as explained above, some of the title V requirements may not be appropriate for certain operations and/or proposed standards. We are also concerned with the potential burden that title V may impose on some of these sources. In light of little or no potential gain in compliance if title V were required, we do not believe that the costs of title V permitting is justified in this case. Finally, there are adequate implementation and enforcement programs in place to assure compliance with these proposed standards. Thus, we propose that title V permitting is ''unnecessarily burdensome'' for the oil and gas non-major sources.

In addition to evaluating whether compliance with title V requirements is ''unnecessarily burdensome,'' EPA also considered, consistent with guidance provided by the legislative history of section 502(a), whether exempting oil and gas NSPS non-major sources from title V requirements would adversely affect public health, welfare or the environment. The title V permit program does not impose new substantive air quality control requirements on sources, but instead requires that certain procedural measures be followed, particularly with respect to determining compliance with applicable requirements. As stated in our consideration of factor one, title V would not lead to significant improvements in the compliance requirements for the proposed NSPS. For the reason stated above, we believe that exempting these non-major sources from title V permitting requirements would not adversely affect public health, welfare or the environment.

On the contrary, we are concerned that requiring title V in this case could potentially adversely affect public health, welfare or the environment. As mentioned above, we anticipate a significant increase in the number of permit applications that permitting authorities would have to process each year. Depending on the number of non-major sources that would be subject to this rule, requiring permits for those sources, at least in the first few years of implementation, could potentially adversely affect public health, welfare or the environment by shifting state agencies resources away from assuring compliance for major sources (which cannot be exempt from title V) to issuing new permits for these non-major sources, potentially reducing overall air program effectiveness.

Based on the above analysis, we conclude that title V permitting would be ''unnecessarily burdensome'' for oil and gas NSPS non-major sources. We are, therefore, proposing that these non-major sources be exempt from title V permitting requirements.

VI. Rationale for Proposed Action for NSPS

A. What did we evaluate relative to NSPS?

As noted above, there are two existing NSPS that address emissions from the Oil and Natural Gas source category. These NSPS are relatively narrow in scope, as they address emissions only at natural gas processing plants. Specifically, 40 CFR part 60, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants and 40 CFR part 60, subpart LLL addresses SO_2 emissions from natural gas processing plants.

CAA section 111(b)(1)(B) requires the EPA to review and revise, if appropriate, NSPS standards. Accordingly, we evaluated whether the existing NSPS reflect the BSER for the emission sources that they address. This review was conducted by examining currently used, new and emerging control systems and assessing whether they represent advances in emission reduction techniques from those upon which the existing NSPS are based, including advances in LDAR approaches and SO_2 control at natural gas processing plants. For each new or emerging control option identified, we then evaluated emission reductions, costs, energy requirements and non-air quality impacts, such as solid waste generation.

In this package, we have also evaluated whether there were additional pollutants emitted by facilities in the Oil and Natural Gas source category that warrant regulation and for which we have adequate information to promulgate standards of performance. Finally, we have identified additional processes in the Oil and Natural Gas source category for which it may be appropriate to develop performance standards. This would include processes that emit the currently regulated pollutants, VOC and SO_2, as well as any additional pollutants for which we determined regulation to be appropriate.

B. What are the results of our evaluations and proposed actions relative to NSPS?

1. Do the existing NSPS reflect the BSER for sources covered?

Consistent with our obligations under CAA section 111(b), we evaluated whether the control options reflected in the current NSPS for the Oil and Natural Gas source category still represent BSER. To evaluate the BSER options for equipment leaks, we reviewed EPA's current LDAR programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, we reviewed the LDAR requirements in 40 CFR part 60, subpart VVa. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. We also reviewed options based on optical gas imaging.

As mentioned above, the currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. We recognize that there have been advancements in the use of optical gas imaging to detect leaks from these same types of components. These instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In our review, we evaluated 4 options in considering BSER for VOC equipment leaks at natural gas processing plants. One option we evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, we estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, we also analyzed separately the individual types of components (valves, connectors, pressure relief devices and open-ended lines) to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are included in the TSD in the docket. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option we evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (*i.e.,* the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). We had previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on that emission reduction level, we determined the cost effectiveness of this option to be $6,462 per ton of VOC reduction. This analysis is based on the facility purchasing an optical gas imaging system costing $85,000. However, we identified at least one manufacturer who rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 checks is $4,638 per ton of VOC reduction.[10] A third option we evaluated consisted of monthly optical gas imaging without an annual Method 21 check. We estimated the annual cost of the monthly optical gas imaging LDAR program to be $76,581, based on camera purchase, or $51,999, based on camera rental. However, because we were unable to estimate the VOC emissions achieved by an optical imaging program alone, we were unable to estimate the cost effectiveness of this option.

Finally, we evaluated a fourth option similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, we estimated the annual cost to be $43,851, based on camera purchase, or $18,479, based on camera rental.

We request comment on the applicability of an LDAR program based solely on the use of optical gas imaging. Of most use to us would be information on the effectiveness of this and, potentially, other advanced measurement technologies, to detect and repair small leaks on the same order or smaller than specified in the 40 CFR part 60, subpart VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording and repair practices.

Because we could not estimate the cost effectiveness of options 3 and 4, we could not identify either of these two options as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 have achieved equivalent VOC reduction and are both cost effective, we believe that both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR. Therefore, we propose that the NSPS for equipment leaks of VOC at gas processing plants be revised to require compliance with the subpart VVa equipment leak requirements.

For 40 CFR part 60, subpart LLL, we reviewed control systems for SO_2 emissions from sweetening units located at natural gas processing plants, including those followed by a sulfur recovery unit. Subpart LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (*i.e.,* H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

We evaluated process modifications and tail gas treatment options when we proposed 40 CFR part 60, subpart LLL. 49 FR 2656, 2659–2660 (1984). As we explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated. As shown in the original evaluation, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics. 49 FR 2656, 2663–2664 (1984). The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, we performed a search of the RBLC database and state regulations. No state regulations identified had emission limitations more stringent than 40 CFR part 60, subpart LLL. However, the RBLC database search identified two entries with SO_2 emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tail-gas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a sulfur feed rate of 280 long tons per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed

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[10] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, we reevaluated the original data. Based on the available cost information, it appears that a 99.9-percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on our review, we are proposing that the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and an H_2S content equal to or greater than 50 percent be raised to 99.9 percent. We are not proposing to make changes to the equations.

Our search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, we are not proposing any changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.

2. What pollutants are being evaluated in this Oil and Natural Gas NSPS package?

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. As discussed elsewhere in this notice, there are NESHAP that address air toxics from the oil and natural gas sector.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990–2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 $MMtCO_2e$ (million metric tons of CO_2-equivalents (CO_2e)).[11] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory). This adjustment would increase the 2009 Inventory estimate by 76.74 $MMtCO_2e$. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 $MMtCO_2e$. Although this proposed rule does not include standards for regulating the GHG emissions discussed above, we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_X) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_X emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_X emissions would be pit flaring of VOC emissions from well completions during periods where REC is not feasible, as would be required under our proposed operational standards for wellhead affected facilities. As discussed below in section VI.B.4 (well completion), pit flaring is the only way we identified of controlling VOC emissions during these periods. Because there is no way of directly measuring the NO_X produced, nor is there any way of applying controls other than minimizing flaring, we propose to allow flaring only when REC is not feasible. We have included our estimates of NO_X formation from pit flaring in our discussion of secondary impacts in section VI.B.4.

3. What emission sources are being evaluated in this Oil and Natural Gas NSPS package?

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where we would expect SO_2 to be emitted directly, although H_2S contained in sour gas, when oxidized in the atmosphere or combusted in boilers and heaters in the field, forms SO_2 as a product of oxidation. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (*i.e.,* they have a heat input of less than 10 million British Thermal Units per hour). However, we may consider addressing them as part of a future sector-based strategy for the oil and natural gas sector.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. As explained above in section V.A, pursuant to CAA section 111(b), to the extent necessary, we are modifying the listed category to include all segments of the oil and natural gas industry for regulation. We are also proposing VOC standards to cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions, pneumatic controllers, compressors and storage vessels.

We believe that produced water ponds are also a potentially significant source of emissions, but we have only limited information. We, therefore, solicit comments on produced water ponds, particularly in the following subject areas:

(a) We are requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation.

(b) We are requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content.

(c) We solicit information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those

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[11] U.S. EPA. *Inventory of U.S. Greenhouse Gas Inventory and Sinks.* 1990–2009. *http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_ExecutiveSummary.pdf.*

warrant control and, if so, how controls should be developed.

(d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. We are seeking information on these considerations as well.

(e) We are also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints.

(f) Finally, we solicit information on separator technologies that are able to improve the oil-water separation efficiency.

4. What are the rationales for the proposed NSPS?

We have provided below our rationales for the proposed BSER determinations and performance standards for a number of VOC emission sources in the Oil and Natural Gas source category that are not covered by the existing NSPS. Our general process for evaluating systems of emission reduction for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, nonair environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent BSER based on the information we considered.

We identified the control options discussed in this package through our review of relevant state and local requirements and mitigation measures developed and reported by the EPA's Natural Gas STAR program. The EPA's Natural Gas STAR program has worked with industry partners since 1993 to identify cost effective measures to reduce emissions of methane and other pollutants from natural gas operations. We relied heavily on this wealth of information in conducting this review. We also identified state regulations, primarily in Colorado and Wyoming, which require mitigation measures for some emission sources in the Oil and Natural Gas source category.

a. NSPS for Well Completions

Well completion activities are a significant source of VOC emissions, which occur when natural gas and non-methane hydrocarbons are vented to the atmosphere during flowback of a hydraulically fractured gas well. Flowback emissions are short-term in nature and occur over a period of several days following fracturing of a new well or refracturing of an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Well recompletions may also include hydraulic fracturing. Hydraulic fracturing is one technique for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Wells that are fractured generally have great amounts of emissions because of the extended length of the flowback period required to purge the well of the fluids and sand that are associated with the fracturing operation. Along with the fluids and sand from the fracturing operation, the 3- to 10-day flowback period also results in emissions of natural gas and VOC that would not occur in large quantities at oil wells or at natural gas wells that are not fractured. Thus, we estimate that gas well completions involving hydraulic fracturing vent substantially more VOC, approximately 200 times more, than completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled well completion emissions for a hydraulically fractured gas well are approximately 23 tons of VOC, where emissions for a conventional gas well completion are around 0.12 tons VOC. These estimates are explained in detail in the TSD available in the docket. Based on our review, we believe that emissions from recompletions of previously completed wells that are fractured or refractured to stimulate production or to begin production from a new production horizon are of similar magnitude and composition as emissions from completions of new wells that have been hydraulically fractured.

EPA has based the NSPS impacts analysis on best available emission data. However, we recognize that there is uncertainty associated with our estimates. For both new completions and recompletions, there are a variety of factors that will determine the length of the flowback period and actual volume of emissions such as the number of zones, depth, pressure of the reservoir, gas composition, etc. This variability means there will be some wells which emit more than the estimated emission factor and some wells that emit less.

During our review, we examined information from the Natural Gas STAR program and the Colorado and Wyoming state rules covering well completions. We identified two subcategories of fractured gas wells: (1) Non-exploratory and non-delineation wells; and (2) exploratory and delineation wells. An exploratory well is the first well drilled to determine the presence of a producing reservoir and the well's commercial viability. A delineation well is a well drilled to determine the boundary of a field or producing reservoir. Because exploratory and delineation wells are generally isolated from existing producing wells, there are no gathering lines available for collection of gas recovered during completion operations. In contrast, non-exploratory and non-delineation wells are located where existing, producing wells are connected to gathering lines and are, therefore, able to be connected to a gathering line to collect recovered salable natural gas product that would otherwise be vented to the atmosphere or combusted.

For subcategory 1, we identified ''green'' completion, which we refer to as REC, as an option for reducing VOC emissions during well completions. REC are performed by separating the flowback water, sand, hydrocarbon condensate and natural gas to reduce the portion of natural gas and VOC vented to the atmosphere, while maximizing recovery of salable natural gas and VOC condensate. In some cases, for a portion of the completion operation, such as when CO_2 or nitrogen is injected with the fracture water, initial gas produced is not of suitable quality to introduce into the gathering line due to CO_2 or nitrogen content or other undesirable characteristic. In such cases, for a portion of the flowback period, gas cannot be recovered, but must be either vented or combusted. In practice, REC are often combined with combustion to minimize the amount of gas and condensate being vented. This combustion process is rather crude, consisting of a horizontal pipe downstream of the REC equipment, fitted with a continuous ignition source and discharging over a pit near the wellhead. Because of the nature of the flowback (*i.e.,* with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a traditional flare control device or other control device, such as a vapor recovery unit, is not feasible. These control devices are not designed to accommodate the multiphase flow consisting of water, sand and hydrocarbon liquids, along with the gas and vapor being controlled. Although ''pit flaring'' does not employ a traditional flare control device, and is not capable of being tested or monitored for efficiency due to the multiphase slug flow and intermittent nature of the discharge of gas, water and sand over the pit, it does provide a means of minimizing vented gas and is preferable to venting. Because of the rather large exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (*e.g.,* dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to pit flare unrecoverable gas safely in every case. In some cases, pit flaring may be prohibited by local ordinance.

Equipment required to conduct REC may include tankage, special gas-liquid-sand separator traps and gas dehydration. Equipment costs associated with REC will vary from well to well. Typical well completions last between 3 and 10 days and costs of performing REC are projected to be between $700 and $6,500 per day, including a cost of approximately $3,523 per completion event for the pit flaring equipment. However, there are savings associated with the use of REC because the gas recovered can be incorporated into the production stream and sold. In fact, we estimate that REC will result in an overall net cost savings in many cases.

The emission reductions for a hydraulically fractured well are estimated to be around 22 tons of VOC. Based on an average incremental cost of $33,237 per completion, the cost effectiveness of REC, without considering any cost savings, is around $1,516 per ton of VOC (which we have previously found to be cost effective on average). When the value of the gas recovered (approximately 150 tons of methane per completion) is considered, the cost effectiveness is estimated as an average net savings of $99 per ton VOC reduced, using standard discount rates. We believe that these costs are very reasonable, given the emission reduction that would be achieved. Aside from the potential hazards associated with pit flaring, in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with REC combined with combustion. However, pit flaring would produce NO_X emissions. Because we believe that these emissions cannot be controlled or measured directly due to the open combustion process characteristic of pit flaring, we used published emission factors (EPA Emission Guidelines AP–42) to estimate the NO_X emissions for purposes of assessing secondary impacts. For category 1 well completions, we estimated that 0.02 tons of NO_X are produced per event. This is based on the assumption that 5 percent of the flowback gas is combusted by the combustion device. The 1.2 tons of VOC controlled during the pit flaring portion of category 1 well completions is approximately 57 times greater than the NO_X produced by pit flaring. Thus, we believe that the benefit of the VOC reduction far outweighs the secondary impact of NO_X formation during pit flaring.

We believe that, based on the analysis above, REC in combination with combustion is BSER for subcategory 1 wells. We considered setting a numerical performance standard for subcategory 1 wells. However, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged over the pit along with water and sand in multiphase slug flow. Therefore, we believe it is not feasible to set a numerical performance standard. Pursuant to section 111(h)(2) of the CAA, we are proposing an operational standard for subcategory 1 wells that would require a combination of REC and pit flaring to minimize venting of gas and condensate vapors to the atmosphere, with provisions for venting in lieu of pit flaring for situations in which pit flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or CO_2. The proposed operational standard would be accompanied by requirements for documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion.

We recognize that there is heterogeneity in well operations and costs, and that while RECs may be cost-effective on average, they may not be for all operators. Nonetheless, EPA is proposing to require an operational standard rather than a performance-based standard (*e.g.,* requiring that some percentage of emissions be flared or captured), because we believe there are no feasible ways for operators to measure emissions with enough certainty to demonstrate compliance with a performance-based standard for REC in combination with pit flaring. The EPA requests comment on this and seeks input on whether alternative approaches to requiring REC for all operators with access to pipelines may exist that would allow operators to meet a performance-based standard if they can demonstrate that an REC is not cost effective.

We have discussed above certain situations where unrecoverable gas would be vented because pit flaring would present a fire hazard or is infeasible because gas is noncombustible due to high concentrations of nitrogen or CO_2. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible, and potential criteria that would support venting in lieu of pit flaring. In addition, we learned that coalbed methane reservoirs may have low pressure, which would present a technical barrier for performing a REC because the well pressure may not be substantial enough to overcome gathering line pressure. In addition, we identified that coalbed methane wells often have low to almost no VOC emissions, even following the hydraulic fracturing process. We solicit comment on criteria and thresholds that could be used to exempt some well completion operations occurring in coalbed methane reservoirs from the requirements for subcategory 1 wells.

Of the 25,000 new and modified fractured gas wells completed each year, we estimate that approximately 3,000 to 4,000 currently employ reduced emission completion. We expect this number to increase to over 21,000 REC annually as operators comply with the proposed NSPS. We estimate that approximately 9,300 new wells and 12,000 existing wells will be fractured or refractured annually that would be subject to subcategory 1 requirements under the NSPS. We believe that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, energy availability could be affected if a shortage of REC equipment was allowed to cause delays in well completions. We request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of REC by the effective date of the NSPS. We also request specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of REC performed annually.

In the event that public comments indicate that available equipment would likely be insufficient to accommodate the increase in number of REC performed, we are considering phasing in requirements for well completions that would achieve an overall comparable level of environmental benefit. For example, operators performing completions of fractured or refractured existing wells (*i.e.,* modified wells) could be allowed to control emissions through pit flaring instead of REC for some period of time. After some date certain, all modified wells would be subject to REC. We solicit comment on the phasing of requirements for REC along with suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS, while also achieving a comparable level of reduced emissions to the air.

Although we have determined that, on average, reduced emission completions are cost effective, well and reservoir characteristics could vary, such that some REC are more cost effective than others. Unlike most stationary source controls, REC equipment is used only for a 3 to 10 day period. Our review found that most operators contract with service companies to perform REC rather than purchase the equipment themselves, which was reflected in our economic analysis. It is also possible that the contracting costs of supplying and operating REC equipment may rise in the short term with the increased demand for those services. We request comment and any available technical information to judge whether our assumption of $33,237 per well completion for this service given the projected number of wells in 2015 subject to this requirement is accurate.

We believe that the proposed rule regulates only significant emission sources for which controls are cost-effective. Nevertheless, we solicit comment and supporting data on appropriate thresholds (*e.g.,* pressure, flowrate) that we should consider in specifying which well completions are subject to the REC requirements for subcategory 1 wells. Comments specifying thresholds should include an analysis of why sources below these thresholds are not cost effective to control.

In addition, there may be economic, technical or other opportunities or barriers associated with performing cost effective REC that we have not identified in our review. For example, some small regulated entities may have an increased source of revenue due to the captured product. On the other hand, some small regulated entities may have less access to REC than larger regulated entities might have. We request information on such opportunities and barriers that we should consider and suggestions for how we may take them into account in structuring the NSPS.

The second subcategory of fractured gas wells includes exploratory wells or delineation wells. Because these types of wells generally are not in proximity to existing gathering lines, REC is not an option, since there is no infrastructure in place to get the recovered gas to market or further processing. For these wells, the only potential control option we were able to identify is pit flaring, described above. As explained above, because of the slug flow nature of the flowback gas, water and sand, control by a traditional flare control device or other control devices, such as vapor recovery units, is infeasible, which leaves pit flaring as the only practicable control system for subcategory 2 wells. As also discussed above, open pit flaring can present a fire hazard or other undesirable impacts in some situations. Aside from the potential hazards associated with pit flaring, in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with pit flaring. However, pit flaring would produce NO_X emissions. As in the case of category 1 wells, we believe that these emissions cannot be controlled or measured directly due to the open combustion process characteristic of pit flaring. We again used published emission factors to estimate the NO_X emissions for purposes of assessing secondary impacts. For category 2 well completions, we estimated that 0.32 tons of NO_X are produced as secondary emissions per completion event. This is based on the assumption that 95 percent of flowback gas is combusted by the combustion device. The 22 tons of VOC reduced during the pit flaring used to control category 2 well completions is approximately 69 times greater than the NO_X produced. Thus, we believe that the benefit of the VOC reduction far outweighs the secondary impact of NO_X formation during pit flaring.

In light of the above, we propose to determine that BSER for subcategory 2 wells would be pit flaring. As we explained above, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged during flowback mixed with water and sand in multiphase slug flow. It is, therefore, not feasible to set a numerical performance standard.

Pursuant to CAA section 111(h)(2), we are proposing an operational standard for subcategory 2 wells that requires minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of pit flaring, with provisions for venting in lieu of pit flaring for situations in which flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or carbon dioxide.

Consistent with requirements for subcategory 1 wells, owners or operators of subcategory 2 wells would be required to document completions and provide justification for periods when gas was vented in lieu of combustion. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible and potential criteria that would support venting in lieu of pit flaring.

For controlling completion emissions at oil wells and conventional (non-fractured) gas wells, we have identified and evaluated the following control options: REC in conjunction with pit flaring and pit flaring alone. Due to the low uncontrolled VOC emissions of approximately 0.007 ton per completion and, therefore, low potential emission reductions from these events, the cost per ton of reduction based on REC would be extremely high (over $700,000 per ton of VOC reduced). We evaluated the use of pit flaring alone as a system for controlling emissions from oil wells and conventional gas wells and determined that the cost cost-effectiveness would be approximately $520,000 per ton for oil wells and approximately $32,000 per ton for conventional gas wells. In light of the high cost per ton of VOC reduction, we do not consider either of these control options to be BSER for oil wells and conventional wells.

We propose that fracturing (or refracturing) and completion of an existing well (*i.e.,* a well existing prior to August 23, 2011) is considered a modification under CAA section 111(a), because physical change occurs to the existing well, which includes the wellbore, casing and tubing, resulting in an emissions increase during the completion operation. The physical change, in this case, would be caused by the reperforation of the casing and tubing, along with the refracturing of the wellbore. The increased VOC emissions would occur during the flowback period following the fracturing or refracturing operation. Therefore, the proposed standards for category 1 and category 2 wells would apply to completions at existing fractured or refractured wells.

EPA seeks comment on the 10 percent per year rate of refracturing for natural gas wells assumed in the impacts analysis found in the TSD. EPA has received anecdotal information suggesting that refracturing could be occurring much less frequently, while others suggest that the percent of wells refractured in a given year could be greater. We seek comment and comprehensive data and information on the rate of refracturing and key factors that influence or determine refracturing frequency.

In addition to well completions, we considered VOC emissions occurring at the wellhead affected facility during subsequent day-to-day operations during well production. As discussed below in section VI.B.1.e, VOC emissions from wellheads are very small during production and account for about 2.6 tons VOC per year. We are not aware of any cost effective controls that can be used to address these relatively small emissions.

b. NSPS for Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure differential and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate. In these ''gas-driven'' pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. The rate at which this release occurs is referred to as the device bleed rate. Bleed rates are dependent on the design of the device. Similar designs will have similar steady-state rates when operated under similar conditions. Gas-driven pneumatic controllers are typically characterized as ''high-bleed'' or ''low-bleed,'' where a high-bleed device releases more than 6 standard cubic feet per hour (scfh) of gas, with 18 scfh bleed rate being what we used in our analyses below. There are three basic designs: (1) Continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure and gas is vented at a steady-state rate; (2) actuating/intermittent devices (high or low-bleed) perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic devices.

For an average high-bleed pneumatic controller located in production (where the content of VOC in the raw product stream is relatively high), the difference in VOC emissions between a high-bleed controller and a low-bleed controller is around 1.8 tpy. For the transmission and storage segment (where the content of VOC in the pipeline quality gas is relatively low), the difference in VOC emissions between a high-bleed controller and a low-bleed controller is around 0.89 tpy. We have developed projections that estimate that approximately 13,600 new gas-driven units in the production segment and 67 new gas-driven units in the transmission and storage segment will be installed each year, including replacement of old units. Not all pneumatic controllers are gas driven. These ''non-gas driven'' pneumatic controllers use sources of power other than pressurized natural gas, such as compressed ''instrument air.'' Because these devices are not gas driven, they do not release natural gas or VOC emissions, but they do have energy impacts because electrical power is required to drive the instrument air compressor system. Electrical service of at least 13.3 kilowatts (kW) is required to power a 10 horsepower (hp) instrument air compressor, which is a relatively small capacity compressor. At sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices can be used. During our review, we determined that gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that approximately half of existing gas processing plants are using non-gas driven devices.

For devices at gas processing plants, we evaluated the use of non-gas driven controllers and low-bleed controllers as options for reducing VOC emissions, with high-bleed controllers being the baseline. As mentioned above, non-gas driven devices themselves have zero emissions, but they do have energy impacts because electrical power is required to drive the instrument air compressor system. In our cost analysis, we determined that the annualized cost of installing and operating a fully redundant 10 hp (13.3 kW) instrument air system (systems generally are designed with redundancy to allow for system maintenance and failure without loss of air pressure), including duplicate compressors, air tanks and dryers, would be $11,090. A system of this size is capable of serving 15 control loops and reducing VOC emissions by 4.2 tpy, for a cost effectiveness of $2,659 per ton of VOC reduced. If the savings of the salable natural gas that would have been emitted is considered, the value of the gas not emitted would help offset the cost for this control, bringing the cost per ton of VOC down to $1,824.

We also evaluated the use of low-bleed controllers in place of high-bleed controllers at processing plants. We evaluated the impact of bleeding 6 standard cubic feet of natural gas per hour, which is the maximum bleed rate from low-bleed controllers, according to manufacturers of these devices. We chose natural gas as a surrogate for VOC, because manufacturers' technical specifications for pneumatic controllers are stated in terms of natural gas bleed rate rather than VOC. The capital cost difference between a new high-bleed controller and a new low-bleed controller is estimated to be $165. Without taking into account the savings due to the natural gas losses avoided, the annual costs are estimated to be around $23 per year, which is a cost of $13 per ton of VOC reduced for the production segment. If the savings of the salable natural gas that would have been emitted is considered, there is a net savings of $1,519 per ton of VOC reduced.

Although the non-gas-driven controller system is more expensive than the low-bleed controller system, it is still reasonably cost-effective. Furthermore, the non-gas-driven controller system achieves a 100-percent VOC reduction in contrast to a 66-percent reduction achieved by a low-bleed controller. Moreover, we believe the collateral emissions from electrical power generation needed to run the compressor are very low. Finally, non-gas-driven pneumatic controllers avoid potentially explosive concentrations of natural gas which can occur as a result of normal bleeding from groups of gas-driven pneumatic controllers located in close proximity, as they often are at gas processing plants. Based on our review described above, we believe that a non-gas-driven controller is BSER for reducing VOC emissions from pneumatic devices at gas processing plants. Accordingly, the proposed standard for pneumatic devices at gas processing plants is a zero VOC emission limit.

For the production (other than processing plants) and transmission and storage segments, where electrical service sufficient to power an instrument air system is likely unavailable and, therefore, only gas-driven devices can be used, we evaluated the use of low-bleed controllers in place of high-bleed controllers. Just as in our analysis of low-bleed controllers as an option for gas processing plants, we evaluated the impact of bleeding 6 standard cubic feet per minute (scfm) of natural gas per hour contrasted with 18 scfm from a high-bleed unit. Again, the capital cost difference between a new high-bleed controller and a new low-bleed controller is estimated to be $165. Without taking into account the savings due to the natural gas losses avoided, the annual costs are estimated to be around $23 per year, which is a cost of $13 per ton of VOC reduced for the production segment. If the savings of the salable natural gas that would have been emitted is considered, there is a net savings for this control. In the transmission and storage segment, where the VOC content of the vented gas is much lower than in the production segment, the cost effectiveness of a low-bleed pneumatic device is estimated to be around $262 per ton of VOC reduced. However, there are no potential offsetting savings to be realized in the transmission and storage segment, since the operators of transmission and storage stations typically do not own the gas they are handling. Based on our evaluation of the emissions and costs, we believe that low-bleed controllers represent BSER for pneumatic controllers in the production (other than processing plants) and transmission and storage segments. Therefore, for pneumatic devices at these locations, we propose a natural gas bleed rate limit of 6.0 scfh to reflect the VOC limit with the use of a low-bleed controller.

There may be situations where high-bleed controllers and the attendant gas bleed rate greater than 6 cubic feet per hour, are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. For such situations, we have provided in the proposed rule an exemption where pneumatic controllers meeting the emission standards discussed above would pose a functional limitation due to their actuation response time or other operating characteristics. We are requesting comments on whether there are other situations that should be considered for this exemption. If you provide such comment, please specify the criteria for such situations that would help assure that only appropriate exemptions are claimed.

The proposed standards would apply to installation of a new pneumatic device (including replacing an existing device with a new device). We consider that a pneumatic device, an apparatus, is an affected facility and each installation is construction subject to the proposed NSPS. See definitions of ‘‘affected facility’’ and ‘‘construction’’ at 40 CFR 60.2.

c. NSPS for Compressors

There are many locations throughout the oil and natural gas sector where compression of natural gas is required to move it along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses the natural gas for transit through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compressor does not require the use of any of the natural gas from the pipeline, but it does require a substantial source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline. Both centrifugal and reciprocating compressors are sources of VOC emissions and were evaluated for coverage under the NSPS.

Centrifugal Compressors. Centrifugal compressors require seals around the rotating shaft to minimize gas leakage and fugitive VOC emissions from where the shaft exits the compressor casing. There are two types of seal systems: Wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere. Degassing of the seal oil emits an average of 47.7 scfm of gas, depending on the operating pressure of the compressor. An uncontrolled wet seal system can emit, on average, approximately 20.5 tpy of VOC during the venting process (production segment) or about 3.5 tpy (transmission and storage segment). We identified two potential control techniques for reducing emissions from degassing of wet seal systems: (1) Routing the gas back to a low pressure fuel stream to be combusted as fuel gas and (2) routing the gas to a flare. We know only of anecdotal, undocumented information on routing of the gas back to a fuel stream and, therefore, were unable to assess costs and cost effectiveness of the first option. Although we do not have specific examples of routing emissions from wet seal degassing to a flare, we were able to estimate the cost, emission reductions and cost effectiveness of the second option using uncontrolled wet seals as a baseline.

Based on the average uncontrolled emissions of wet seal systems discussed above and a flare efficiency of 95 percent, we determined that VOC emission reductions from a wet seal system would be an average of 19.5 tpy (production segment) or 3.3 tpy (transmission and storage segment). Using an annualized cost of flare installation and operation of $103,373, we estimated the incremental cost effectiveness of this option (from uncontrolled wet seals to controlled wet seals using a flare) to be approximately $5,300/ton and $31,000/ton for the production segment and transmission and storage segment, respectively. With this option, there would be secondary air impacts from combustion. However we did not identify any nonair quality or energy impacts associated with this control technique.

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Fugitive emissions occur from dry seals around the compressor shaft. Based on manufacturer studies and engineering design estimates, fugitive emissions from dry seal systems are approximately 6 scfm of gas, depending on the operating pressure of the compressor. A dry seal system can have fugitive emissions of, on average, approximately 2.6 tpy of VOC (production segment) or about 0.4 tpy (transmission and storage segment). We did not identify any control device suitable to capture and control the fugitive emissions from dry seals around the compressor shaft.

Using uncontrolled wet seals as a baseline, we evaluated the reductions and incremental cost effectiveness of dry seal systems. Based on the average fugitive emissions, we determined that VOC emission reductions achieved by dry seal systems compared to uncontrolled wet seal systems would be 18 tpy (production segment) and 3.1 tpy (transmission and storage segment). Combined with an annualized cost of dry seal systems of $10,678, the incremental cost effectiveness compared to uncontrolled wet seal systems would be $595/ton and $3,495/ton for the production segment and transmission and storage segment, respectively. We identified neither nonair quality nor any energy impacts associated with this option.

In performing our analysis, we estimated the incremental cost of a dry seal compressor over that of an equivalent wet seal compressor to be $75,000. This value was obtained from a vendor who represents a large share of the market for centrifugal compressors. However, this number likely represents a conservatively high value because wet seal units have a significant amount of ancillary equipment, namely the seal oil system and, thus, additional capital expenses. Dry seal systems have some ancillary equipment (the seal gas filtration system), but the costs are less than the wet seal oil system. We were not able to directly confirm this assumption with the vendor, however, a search of product literature showed that seal oil systems and seal gas filtration systems are typically listed separate from the basic compressor package. Using available data on the cost of this equipment, it is very likely that the cost of purchasing a dry seal compressor may actually be lower that a wet seal compressor. We seek comment on available cost data of a dry seal versus wet seal compressor, including all ancillary equipment costs.

In light of the above analyses, we propose to determine that dry seal systems are BSER for reducing VOC emissions from centrifugal compressors. We evaluated the possibility of setting a performance standard that reflects the emission limitation achievable through the use of a dry seal system. However, as mentioned above, VOC from centrifugal compressors with dry seals are fugitive emissions from around the compressor shafts. There is no device to capture and control these fugitive emissions, nor can reliable measurement of these emissions be conducted due to difficulty in accessing the leakage area and danger of contacting the shaft rotating at approximately 30,000 revolutions per minute. This not only poses a likely hazard that would destroy test equipment on contact, it poses a safety hazard to personnel, as well. Therefore, pursuant to section 111(h)(2) of the CAA, we are proposing an equipment standard that would require the use of dry seals to limit the VOC emissions from new centrifugal compressors. We consider that a centrifugal compressor, an apparatus, is an affected facility and each installation is construction subject to the proposed NSPS. See definitions of ‘‘affected facility’’ and ‘‘construction’’ at 40 CFR 60.2. Accordingly, the proposed standard would apply to installation of new centrifugal compressors at new locations, as well as replacement of old compressors.

Although we are proposing to determine dry seal systems to be BSER for centrifugal compressors, we are soliciting comments on the emission reduction potential, cost and any limitations for the option of routing the gas back to a low pressure fuel stream to be combusted as fuel gas. In addition, we solicit comments on whether there are situations or applications where wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate.

Reciprocating Compressors. Reciprocating compressors in the natural gas industry leak natural gas fugitive VOC during normal operation. The highest volumes of gas loss and fugitive VOC emissions are associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the high pressure gas in the compressor cylinder from leaking, while allowing the rod to move freely. This leakage rate is dependent on a variety of factors, including physical size of the compressor piston rod, operating speed and operating pressure. Under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh. Higher leak rates are a consequence of fit, alignment of the packing parts and wear.

We evaluated the possibility of reducing VOC emissions from reciprocal compressors through a control device. However, VOC from reciprocating compressors are fugitive emissions from around the compressor shafts. Although it is possible to construct an enclosure around the rod packing area and vent the emissions outside for safety purposes, connection to a closed vent system and control device would create back pressure on the leaking gas. This back pressure would cause the leaked gas instead to be forced inside the crankcase of the engine, which would dilute lubricating oil, causing premature failure of engine bearings, pose an explosion hazard and eventually be vented from the crankcase breather, defeating the purpose of a control device.

As mentioned above, as packing wears and deteriorates, leak rates can increase. We, therefore, evaluate replacement of compressor rod packing systems as an option for reducing VOC emissions. Conventional bronze-metallic packing rings wear out and need to be replaced every 3 to 5 years, depending on the compressor's rate of usage (*i.e.,* the percentage of time that a compressor is in pressurized mode).

Based on industry experience in the Natural Gas STAR program and other sources, we evaluated the rod packing replacement costs for reciprocating compressors at different segments of this industry. Usage rates vary by segment. Usage rates for compressors at wellheads, gathering/boosting stations, processing plants, transmission stations and storage facilities are 100, 79, 90, 79 and 68 percent, respectively. Reciprocating compressors at wellheads are small and operate at lower pressures, which limit VOC emissions from these sources. Due to the low VOC emissions from these compressors, about 0.044 tpy, combined with an annual cost of approximately $3,700, the cost per ton of VOC reduction is rather high. We estimated that the cost effectiveness of controlling wellhead compressors is over $84,000 per ton of VOC reduced, which we believe to be too high and, therefore, not reasonable. Because the cost effectiveness of replacing packing wellhead compressor rod systems is not reasonable, and absent other emission reduction measures, we did not find a BSER for reducing VOC emissions from reciprocal compressors at wellheads.

For reciprocating compressors located at other oil and gas operations, we estimated that the cost effectiveness of controlling compressor VOC emissions by rod packing replacement would be $870 per ton of VOC for reciprocating compressors at gathering and boosting stations, $270 per ton of VOC for reciprocating compressors at processing stations, $2,800 per ton of VOC for reciprocating compressors at transmission stations and $3,700 per ton of VOC for reciprocating compressors at underground storage facilities. We consider these costs to be reasonable. We did not identify any nonair quality health or environmental impacts or energy impacts associated with rod packing replacement. In light of the above, we propose to determine that such control is the BSER for reducing

VOC emission from compressors at these other oil and gas operations.

Because VOC emitted from reciprocal compressors are fugitive emissions, there is no device to capture and control the emissions. Therefore, pursuant to section 111(h) of the CAA, we are proposing an operational standard. Based on industry experience reported to the Natural Gas STAR program, we determined that packing rods should be replaced every 3 years of operation. However, to account for segments of the industry in which reciprocating compressors operate in pressurized mode a fraction of the calendar year (ranging from approximately 68 percent up to approximately 90 percent), the proposed rule expresses the replacement requirement in terms of hours of operation rather than on a calendar year basis. One year of continuous operation would be 8,760 hours. Three years of continuous operation would be 26,280 hours, or rounded to the nearest thousand, 26,000 hours. Accordingly, the proposed rule would require the replacement of the rod packing every 26,000 hours of operation. The owner or operator would be required to monitor the hours of operation beginning with the installation of the reciprocating compressor affected facility. Cumulative hours of operation would be reported each year in the facility's annual report. Once the hours of operation reached 26,000 hours, the owner or operator would be required to change the rod packing immediately, although unexpected shutdowns could be avoided by tracking hours of operation and planning for packing replacement at scheduled maintenance shutdowns before the hours of operation reached 26,000.

Some industry partners of the Natural Gas STAR program currently conduct periodic testing to determine the leakage rates that would identify economically beneficial replacement of rod packing based on natural gas savings. Therefore, we are soliciting comments on incorporating a method similar to that in the Natural Gas STAR's Lessons Learned document entitled, *Reducing Methane Emissions from Compressor Rod Packing Systems* (*http://www.epa.gov/gasstar/documents/ll_rodpack.pdf*), to be incorporated in the NSPS. We are soliciting comments on how to determine a suitable leak threshold above which rod packing replacement would be cost effective for VOC emission reduction. We are also soliciting comment on the appropriate replacement frequency and other considerations that would be associated with regular replacement periods.

d. NSPS for Storage Vessels

Crude oil, condensate and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located as part of a tank battery. A tank battery refers to the collection of process equipment used to separate, treat and store crude oil, condensate, natural gas and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells.

Emissions from storage vessels are a result of working, breathing and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing dissolved gases and a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid also influences the amount of flash emissions. The amount of liquid entering the tank during a given time, commonly known as throughput, also affects the emission rate, with higher throughput tanks having higher annual emissions, given that other parameters are the same.

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks. The other option would be to route the emissions from the tanks to a flare control device. These devices could be ''candlestick'' flares that are found at gas processing plants or other larger facilities or enclosed combustors which are commonly found at smaller field facilities. We estimated the total annual cost for a VRU to be approximately $18,900/yr and for a flare to be approximately $8,900/yr. Cost effectiveness of these control options depend on the amount of vapor produced by the storage vessels being controlled. A VRU has a potential advantage over flaring, in that it recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold, as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts that flaring does, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: Availability of electrical service sufficient to power the VRU; fluctuations in vapor loading caused by surges in throughput and flash emissions from the tank; potential for drawing air into condensate tanks causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

Like a VRU, a flare control device can also achieve a control efficiency of 95 percent. There are no technical limitations on the use of flares to control vapors from condensate and crude oil tanks. However, flaring has a secondary impact from emissions of NO_X and other pollutants. In light of the technical limitations with the use of a VRU, we are unable to conclude that a VRU is better than flaring. We, therefore, propose to determine that both a VRU and flare are BSER for reducing VOC emission from storage vessels. We propose an NSPS of 95-percent reduction for storage vessels to reflect the level of emission reduction achievable by VRU and flares.

VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (*i.e.,* its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. We do not believe that it is cost effective to control these vessels. We believe it is important to control tanks with significant VOC emissions under the proposed NSPS.

In our analysis, we evaluated storage tanks with varying condensate or crude oil throughput. We used emission factors developed for the Texas Environmental Research Consortium in a study that evaluated VOC emissions from crude oil and condensate storage tanks by performing direct measurements. The study found that the average VOC emission factor for crude oil storage tanks was 1.6 pounds (lb) VOC per barrel of crude oil throughput. The average VOC emission factor for condensate tanks was determined to be 33.3 lb VOC per barrel of condensate throughput. Applying these emission factors and evaluating condensate throughput rates of 0.5, 1, 2 and 5 barrels per day (bpd), we determined that VOC emissions at these condensate throughput rates would be approximately 3, 6, 12 and 30 tpy, respectively. Similarly, we evaluated crude oil throughput rates of 1, 5, 20 and 50 bpd. Based on the Texas study, these crude oil throughput rates would result in VOC emissions of 0.3, 1.5, 5.8 and 14.6 tpy, respectively. We believe that it is important to control tanks with significant VOC emissions. Furthermore, we believe it would be easier and less costly for owners and operators to determine applicability by using a throughput threshold instead of an emissions threshold. As a result of the above analyses, we believe that storage vessels with at least 1 bpd of condensate or 20 bpd of crude oil should be controlled. These throughput rates are equivalent to VOC emissions of approximately 6 tpy. Based on an estimated annual cost of $18,900 for the control device, controlling storage vessels with these condensate or crude oil throughputs would result in a cost effectiveness of $3,150 per ton of VOC reduced.

Based on our evaluation, we propose to determine that both a VRU and flare are BSER for reducing VOC emission from storage vessels with throughput of at least 1 barrel of condensate per day or 20 barrels of crude oil per day. We propose an NSPS of 95-percent reduction for these storage vessels to reflect the level of emission reduction achievable by VRU and flare control devices.

For storage vessels below the throughput levels described above (''small throughput tanks''), for which we do not consider flares or VRU to be cost effective controls, we evaluated other measures to reduce VOC emissions. Standard practices for such tanks include requiring a cover that is well designed, maintained in good condition and kept closed. Crude oil and condensate storage tanks in the oil and natural gas sector are designed to operate at or just slightly above or below atmospheric pressure. Accordingly, they are provided with vents to prevent tank destruction under rapid pressure increases due to flash emissions conditions. Studies by the Natural Gas STAR program and by others have shown that working losses (*i.e.,* those emissions absent flash emission conditions) are very low, approaching zero. During times of flash emissions, tanks are designed such that the flash emissions are released through a vent on the fixed roof of the tank when pressure reaches just a few ounces to prevent pressure buildup and resulting tank damage. At those times, vapor readily escapes through the vent to protect the tank. Tests have shown that open hatches or leaking hatch gaskets have little effect on emissions from uncontrolled tanks due to the functioning roof vent. However, in the case of controlled tanks, the control requirements include provisions for maintaining integrity of the closed vent system that conveys emissions to the control device, including hatches and other tank openings. As a result, hatches are required to be kept closed and gaskets kept in good repair to meet control requirements of controlled storage vessels. Because the measures we evaluated, including maintenance of hatch integrity, do not provide appreciable emission reductions for storage vessels with throughputs under 1 barrel of condensate per day and 21 barrels of crude oil per day, we believe that the control options we evaluated do not reflect BSER for the small throughput tanks and we are not proposing standards for these tanks.

As discussed in section VII of this preamble, we are proposing to amend the NESHAP for oil and natural gas production facilities at 40 CFR part 63, subpart HH to require that all storage vessels at production facilities reduce HAP emissions by 95 percent. Because the controls used to achieve the 95-percent HAP reduction are the same as the proposed BSER for VOC reduction for storage vessels (*i.e.,* VRU and flare), sources that are achieving the 95-percent HAP reduction would also be meeting the proposed NSPS of 95-percent VOC reduction. In light of the above, and to avoid duplicate monitoring, recordkeeping and reporting, we propose that storage vessels subject to the requirements of subpart HH are exempt from the proposed NSPS for storage vessel in 40 CFR part 60, subpart OOOO.

e. NSPS for VOC Equipment Leaks

Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps and other components within an oil and gas production, processing and transmission facility, equipment leak volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption and transmission stations tend to have a large number of components. Equipment leaks from processing plants are addressed in our review of 40 CFR part 60, subpart KKK, which is discussed above in section VI.B.1.

In addition to gas processing plants, these types of equipment also exist at oil and gas production sites and gas transmission and storage facilities. While the number of components at individual transmission and storage facilities is relatively smaller than at processing plants, collectively, there are many components that can result in significant emissions.

Therefore, we evaluated applying NSPS for equipment leaks to facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant, transmission pipeline or distribution pipeline. Production facilities can vary significantly in the operations performed and the processes, all of which impact the number of components and potential emissions from leaking equipment and, thus, impact the annual costs related to implementing a LDAR program. We used data collected by the Gas Research Institute to develop model production facilities. Baseline emissions, along with emission reductions and costs of regulatory alternatives, were estimated using these model production facilities. We considered production facilities where separation, storage, compression and other processes occur. These facilities may not have a wellhead on-site, but would be associated with a wellhead. We also evaluated gathering and boosting facilities, where gas and/or oil are collected from a number of wells, then processed and transported downstream to processing plants or transmission stations. We evaluated the impacts at these production facilities with varying number of operations and equipment. We also developed a model plant for the transmission and storage segment using data from the Gas

Research Institute. Details of these evaluations may be found in the TSD in the docket.

For an average production site at or associated with a wellhead, we estimated annual VOC emissions from equipment leaks of around 2.6 tpy. For an average gathering/boosting facility, we estimated the annual VOC emissions from equipment leaks to be around 9.8 tpy. The average transmission and storage facility emits 2.7 tpy of VOC.

For facilities in each non-gas processing plant segment, we evaluated the same four options as we did for gas processing plants in section VI.B.1 above. These four options are as follows: (1) 40 CFR part 60, subpart VVa-level LDAR (which is based on conducting Method 21 monthly, defining ''leak'' at 500 ppm threshold, and adding connectors to the VV list of components to be monitored); (2) monthly optical gas imaging with annual Method 21 check (the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)); (3) monthly optical gas imaging alone; and (4) annual optical gas imaging alone.

For option 1, we evaluated subpart VVa-LDAR as a whole. We also analyzed separately the individual types of components (valves, connectors, pressure relief devices and open-ended lines). Detailed discussions of these component by component analyses are included in the TSD in the docket.

Based on our evaluation, subpart VVa-level LDAR (Option 1) results in more VOC reduction than the subpart VV-level LDAR currently required for gas processing plants, because more leaks are found based on the lower definition of ''leak'' under subpart VVa (10,000 ppm for subpart VV and 500 ppm for subpart VVa). In addition, our evaluation shows that the cost per ton of VOC reduced for subpart VVa level controls is less than the cost per ton of VOC reduced for the less stringent subpart VV level of control. Although the cost of repairing more leaks is higher, the increased VOC control afforded by subpart VVa level controls more than offsets the increased costs.

For the subpart VVa level of control at the average production site associated with a wellhead, average facility-wide cost-effectiveness would be $16,084 per ton of VOC. Component-specific cost-effectiveness ranged from $15,063 per ton of VOC (for valves) to $211,992 per ton of VOC (for pressure relief devices), with connectors and open-ended lines being $74,283 and $180,537 per ton of VOC, respectively. We also looked at component costs for a modified subpart VVa level of control with less frequent monitoring for valves and connectors at production sites associated with a wellhead.[12] The cost-effectiveness for valves was calculated to be $17,828 per ton of VOC by reducing the monitoring frequency from monthly to annually. The cost-effectiveness for connectors was calculated to be $87,277 per ton of VOC by reducing the monitoring frequency from every 4 years to every 8 years after the initial compliance period.

We performed a similar facility-wide and component-specific analysis of option 1 LDAR for gathering and boosting stations. For the subpart VVa level of control at the average gathering and boosting station, facility-wide cost-effectiveness was estimated to be $9,344 per ton of VOC. Component-specific cost-effectiveness ranged from $6,079 per ton of VOC (for valves) to $77,310 per ton of VOC (for open-ended lines), with connectors and pressure relief devices being $23,603 and $72,523 per ton, respectively. For the modified subpart VVa level of control at gathering and boosting stations, cost-effectiveness ranged from $5,221 per ton of VOC (for valves) to $77,310 per ton of VOC (for open-ended lines), with connectors and pressure relief devices being $27,274 and $72,523 per ton, respectively. The modified subpart VVa level controls were more cost-effective than the subpart VVa level controls for valves, but not for connectors. This is due to the low cost of monitoring connectors and the low VOC emissions from leaking connectors.

We also performed a similar analysis of option 1 subpart VVa-level LDAR for gas transmission and storage facilities. For the subpart VVa level of control at the average transmission and storage facility, facility-wide cost-effectiveness was $20,215. Component-specific cost-effectiveness ranged from $24,762 per ton of VOC (for open-ended lines) to $243,525 per ton of VOC (for pressure relief devices), with connectors and valves being $36,527 and $43,111 per ton of VOC, respectively. For the modified subpart VVa level of control at transmission and storage facilities, cost-effectiveness ranged from $24,762 per ton of VOC (for open-ended lines) to $243,525 per ton of VOC (for pressure relief devices), with connectors and valves being $42,140 and $40,593 per ton of VOC, respectively. Again, the modified subpart VVa level controls were more cost-effective for valves and less cost effective for connectors than the subpart VVa level controls. This is due to the low cost of monitoring connectors and the low VOC emissions from leaking connectors.

For each of the non-gas processing segments, we also evaluated monthly optical gas imaging with annual Method 21 check (Option 2). As discussed in secton VI.B.1, we had previously determined that the VOC reductions achieved under this option would be the same as for option 1 subpart VVa-level LDAR. In our evaluation of Option 2, we estimated that a single optical imaging instrument could be used for 160 well sites and 13 gathering and boosting stations, which means that the cost of the purchase or rental of the camera would be spread across 173 facilities.

For production sites, gathering and boosting stations, and transmission and storage facilities, we estimated that option 2 monthly optical gas imaging with annual Method 21 check would have cost-effectiveness of $16,123, $10,095, and $19,715 per ton of VOC, respectively.[13]

The annual costs for option 1 and option 2 leak detection and repair programs for production sites associated with a wellhead, gathering and boosting stations and transmission and storage facilities were higher than those estimated for natural gas processing plants because natural gas processing plant annual costs are based on the incremental cost of implementing subpart VVa-level standards, whereas the other facilities are not currently regulated under an LDAR program. The currently unregulated sites would be required to set up a new LDAR program; perform initial monitoring, tagging, logging and repairing of components; as well as planning and training personnel to implement the new LDAR program.

In addition to options 1 and 2, we evaluated a third option that consisted of monthly optical gas imaging without an annual Method 21 check. Because we were unable to estimate the VOC emissions achieved by an optical imaging program alone, we were unable to estimate the cost-effectiveness of this option. However, we estimated the annual cost of the monthly optical gas imaging LDAR program at production sites, gathering and boosting stations, and transmission and storage facilities to be $37,049, $86,135, and $45,080, respectively, based on camera purchase, or $32,693, $81,780, and $40,629, respectively, based on camera rental.

Finally, we evaluated a fourth option similar to the third option except that the optical gas imaging would be performed annually rather than monthly. For this option, we estimated the annual cost for production sites, gathering and boosting stations, and transmission and storage facilities to be

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[13] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

$30,740, $64,416, and $24,031, respectively, based on camera purchase, or $26,341, $60,017, and $19,493, respectively, based on camera rental.

We request comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies. Of most use to us would be information on the effectiveness of advanced measurement technologies to detect and repair small leaks on the same order or smaller as specified in the VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording, and repair practices.

Based on the evaluation described above, we believe that neither option 1 nor option 2 is cost effective for reducing fugitive VOC emissions from equipment leaks at sites, gathering and boosting stations, and transmission and storage facilities. For options 3 and 4, we were unable to estimate their cost effectiveness and, therefore, could not identify either of these two options as BSER for addressing equipment leak of VOC at production facilities associated with wellheads, at gathering and boosting stations or at gas transmission and storage facilities. We are, therefore, not proposing NSPS for addressing VOC emissions from equipment leaks at these facilities.

5. What are the SSM provisions?

The EPA is proposing standards in this rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction. In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods.

The General Provisions in 40 CFR part 60 require facilities to keep records of the occurrence and duration of any startup, shutdown or malfunction (40 CFR 60.7(b)) and either report to the EPA any period of excess emissions that occurs during periods of SSM (40 CFR 60.7(c)(2)) or report that no excess emissions occurred (40 CFR 60.7(c)(4)). Thus, any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 60.2.) The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards. Further, nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. See, *Weyerhaeuser* v *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''), and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards.

Further, it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. Applying the concept of ''the application of the best system of emission reduction'' to periods during which a source is malfunctioning presents difficulties. The ''application of the best system of emission reduction'' is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for affected facilities under 40 CFR part 60, subpart OOOO. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail. Such failure can sometimes cause an exceedance of the relevant emission standard (See, *e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). The EPA is, therefore, proposing to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 60.41Da (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 60.46Da. (See 40 CFR 22.24). These criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 60.40Da and to prevent future malfunctions. For example, the source would have to prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met the burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (see also 40 CFR part 22.77).

VII. Rationale for Proposed Action for NESHAP

A. What data were used for the NESHAP analyses?

To perform the technology review and residual risk analysis for the two NESHAP, we created a comprehensive dataset (*i.e.,* the MACT dataset). This dataset was based on the EPA's 2005 National Emissions Inventory (NEI). The NEI database contains information about sources that emit criteria air pollutants and their precursors and HAP. The database includes estimates of annual air pollutant emissions from point, nonpoint and mobile sources in the 50 states, the District of Columbia, Puerto Rico and the Virgin Islands. The EPA collects information about sources and releases an updated version of the NEI database every 3 years.

The NEI database is compiled from these primary sources:

- Emissions inventories compiled by state and local environmental agencies
- Databases related to the EPA's MACT programs
- Toxics Release Inventory data
- For electric generating units, the EPA's Emission Tracking System/CEM data and United States Department of Energy (DOE) fuel use data
- For onroad sources, the United States Federal Highway Administration's estimate of vehicle miles traveled and emission factors from the EPA's MOBILE computer model
- For nonroad sources, the EPA's NONROAD computer model
- Emissions inventories from previous years, if states do not submit current data

To concentrate on only records pertaining to the oil and natural gas industry sector, data were extracted using two criteria. First, we specified that all facilities containing codes identifying the Oil and Natural Gas Production and the Natural Gas Transmission and Storage MACT source categories (MACT codes 0501 and 0504, respectively). Second, we extracted facilities identified with the following NAICS codes: 211 * * * (Oil and Gas Extraction), 221210 (Natural Gas Distribution), 4861 * * * (Pipeline Transportation of Crude Oil), and 4862 * * * (Pipeline Transportation of Natural Gas). Once the data were extracted, we reviewed the Source Classification Codes (SCC) to assess whether there were any records included in the dataset that were clearly not a part of the oil and natural gas sector. Our review of the SCC also included assigning each SCC to an ''Emission Process Group'' that represents emission point types within the oil and natural gas sector.

Since these MACT standards only apply to major sources, only facilities designated as major sources in the NEI were extracted. In the NEI, sources are identified as major if the facility-wide emissions are greater than 10 tpy for any single HAP or 25 tpy for any combination of HAP. We believe that this may overestimate the number of major sources in the oil and natural gas sector because it does not take into account the limitations set forth in the CAA regarding aggregation of emissions from wells and associated equipment in determining major source status.

The final dataset contained a total of 1,311 major sources in the oil and natural gas sector; 990 in Oil and Natural Gas Production, and 321 in Natural Gas Transmission and Storage. To assess how representative this number of facilities was, we obtained information on the number of subject facilities for both MACT standards from the Enforcement and Compliance History Online (ECHO) database. The ECHO database is a web-based tool (*http://www.epa-echo.gov/echo/index.html*) that provides public access to compliance and enforcement information for approximately 800,000 EPA-regulated facilities. The ECHO database allows users to find permit, inspection, violation, enforcement action and penalty information covering the past 3 years. The site includes facilities regulated as CAA stationary sources, as well as Clean Water Act direct dischargers, and Resource Conservation and Recovery Act hazardous waste generators/handlers. The data in the ECHO database are updated monthly.

We performed a query on the ECHO database requesting records for major sources, with NAICS codes 211*, 221210, 4861* and 4862*, with information for MACT. The ECHO database query identified records for a total of 555 facilities, 269 in the Oil and Natural Gas Production source category (NAICS 211* and 221210) and 286 in the Natural Gas Transmission and Storage source category (NAICS 4861* and 4862*). This comparison leads us to conclude that, for the Natural Gas Transmission and Storage segment, the NEI database is representative of the number of sources subject to the rule. For the Oil and Natural Gas Production source category, it confirms our assumption that the NEI dataset contains more facilities than are subject to the rule. However, this provides a conservative overestimate of the number of sources, which we believe is appropriate for our risk analyses.

We are requesting that the public provide a detailed review of the information in this dataset and provide comments and updated information where appropriate. Section X of this preamble provides an explanation of how to provide updated information for these datasets.

B. What are the proposed decisions regarding certain unregulated emissions sources?

In addition to actions relative to the technology review and risk reviews discussed below, we are proposing, pursuant to CAA sections 112(d)(2) and (3), MACT standards for glycol dehydrators and storage vessels for which standards were not previously developed. We are also proposing changes that affect the definition of ''associated equipment'' which could apply these MACT standards to previously unregulated sources.

1. Glycol Dehydrators

Once natural gas has been separated from any liquid materials or products (*e.g.,* crude oil, condensate or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions.

Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The majority of glycol dehydration units use triethylene glycol as the absorbent, but ethylene glycol and diethylene glycol are also used. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol (GCG) separator (flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent.

The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water, but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device. The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

In the development of the MACT standards for the two oil and natural gas source categories, the EPA created two subcategories of glycol dehydrators based on actual annual average natural gas flowrate and actual average benzene emissions. Under 40 CFR part 63, subpart HH, (the Oil and Natural Gas Production NESHAP), the EPA established MACT standards for glycol dehydration units with an actual annual average natural gas flowrate greater than or equal to 85,000 scmd and actual average benzene emissions greater than or equal to 0.90 Mg/yr (40 CFR 63.765(a)). The EPA did not establish standards for the other subcategory, which consists of glycol dehydration units that are below the flowrate and emission thresholds specified in subpart HH. Similarly, under 40 CFR part 63, subpart HHH (the Natural Gas Transmission and Storage NESHAP), the EPA established MACT standards for the subcategory of glycol dehydration units with an actual annual average natural gas flowrate greater than or equal to 283,000 scmd and actual average benzene emissions greater than or equal to 0.90 Mg/yr, but did not establish standards for the other subcategory, which consists of glycol dehydration units that are below the flowrate and emission thresholds specified in subpart HHH. As mentioned above, we refer to these unregulated dehydration units in both subparts HH and HHH as ''small dehydrators'' in this proposed rule.

The EPA is proposing emission standards for these subcategories of small dehydrators (*i.e.,* those dehydrators with an actual annual average natural gas flowrate less than 85,000 scmd at production sites or 283,000 scmd at natural gas transmission and storage sites, or actual average benzene emissions less than 0.9 Mg/yr). Because we do not have any new emissions data concerning these emission points, we evaluated the dataset collected from industry during the development of the original MACT standards (legacy docket A–94–04, item II–B–01, disk 1 for oil and natural gas production facilities; and items IV–G–24, 26, 27, 30 and 31 for natural gas transmission and storage facilities). We believe this dataset is representative of currently operating glycol dehydrators because it contains information for a varied group of sources (*i.e.,* units owned by different companies, located in different states, representing a range of gas compositions and emission controls) and that the processes have not changed significantly since the data were collected.

In the Oil and Natural Gas Production source category, there were 91 glycol dehydration units with throughput and emissions data identified that would be classified as small glycol dehydration units. We evaluated the possibility of establishing a MACT floor as a Mg/yr limit. However, due to variability of gas throughput and inlet gas composition, we could not properly identify the best performing units by only considering emissions. To allow us to normalize the emissions for a more accurate determination of the best performing sources, we created an emission factor in terms of grams BTEX/scm-ppmv for each facility. The emission factor reflects the facility's emission level, taking into consideration its natural gas throughput and inlet natural gas BTEX concentration. To determine the MACT floor for the existing dehydrators, we ranked each unit from lowest to highest, based on their emission factor, to determine the facilities in the top 12 percent of the dataset. The MACT floor was an emission factor of 1.10×10^{-4} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device.

We also considered beyond-the-floor options for the existing sources, as required by section 112(d)(2) of the CAA. To achieve further reductions beyond the MACT floor level of control, sources would have to install an additional add-on control device, most likely a combustion device. Assuming the MACT floor control device is a combustion device, which generally achieves at least a 95-percent HAP reduction, then less than 5 percent of the initial HAP emissions remain. Installing a second device would involve the same costs as the first control, but would only achieve 1⁄20 of the reduction (*i.e.,* reducing the remaining 5 percent by another 95 percent represents a 4.49-percent reduction of the initial, uncontrolled emissions, which is 1⁄20 of the 95-percent reduction achieved with the first control). Based on the $8,360/Mg cost effectiveness of the floor level of control, we estimate that the incremental cost effectiveness of the second control to be $167,200/Mg. We do not believe this cost to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for existing small dehydrators that reflects the MACT floor.

For new small glycol dehydrators in the Oil and Natural Gas Production source category, based on our performance ranking, the best performing source has an emission factor of 4.66×10^{-6} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device. The consideration of beyond-the-floor options for new small dehydrators would be the same as for existing small dehydrators, and, as stated above, we do not believe a cost of $167,200/Mg to be reasonable given the level of emission reduction. We are, therefore, proposing a MACT standard for new small dehydrators that reflects the MACT floor level of control.

Under our proposal, a small dehydrator's actual MACT emission limit would be determined by multiplying the MACT floor emission factor in g BTEX/scm-ppmv by its unit-specific incoming natural gas throughput and BTEX concentration for the dehydrator. A formula is provided in 40 CFR 63.765(b)(1)(iii) to calculate the MACT limit as an annual value.

In the Natural Gas Transmission and Storage source category, there were 16 facilities for which throughput and emissions data were available that would be classified as small glycol dehydration units. Since the number of units was less than 30, the MACT floor for existing sources was based on the top five performing units. Using the same emission factor concept, we determined that the MACT floor for existing sources is an emission factor equal to 6.42×10^{-5} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device.

We also considered beyond-the-floor options for the existing small dehydrators as required by section 112(d)(2) of the CAA. To achieve further reductions beyond the MACT floor level of control, sources would have to install an additional add-on control device, most likely a combustion device. Assuming the MACT floor control device is a combustion device, which generally achieves at least a 95-percent HAP reduction, then less than 5 percent of the initial HAP emissions remain. Installing a second device would involve the same costs as the first control device, but would only achieve $1/20$ of the reduction (*i.e.,* reducing the remaining 5 percent by another 95 percent represents a 4.49-percent reduction of the initial, uncontrolled emissions, which is $1/20$ of the 95-percent reduction achieved with the first control). Based on the $1,650/Mg cost effectiveness of the floor level of control, we estimate that the incremental cost effectiveness of the second control to be $33,000/Mg. We do not believe this cost to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for existing small dehydrators that reflects the MACT floor.

For new small glycol dehydrators, based on our performance ranking, the best performing source has an emission factor of 1.10×10^{-5} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device. The consideration of beyond-the-floor options for new small dehydrators would be the same as for existing small dehydrators, and, as stated above, we do not believe a cost of $33,000/Mg to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for new sources that reflects the MACT floor level of control.

Under our proposal, a source's actual MACT emissions limit would be determined by multiplying this emission factor by their unit-specific incoming natural gas throughput and BTEX concentration for the dehydrator. A formula is provided in 40 CFR 63.1275(b)(1)(iii) to calculate the limit as an annual value.

As discussed below, we are proposing that, with the removal of the 1-ton alternative compliance option from the existing standards for glycol dehydrators, the MACT for these two source categories would provide an ample margin of safety to protect public health. We, therefore, maintain that, after the implementation of the small dehydrator standards discussed above, these MACT will continue to provide an ample margin of safety to protect public health. Consequently, we do not believe it will be necessary to conduct another residual risk review under CAA section 112(f) for these two source categories 8 years following promulgation of the small dehydrator standards merely due to the addition of these new MACT requirements.

2. Storage Vessels

Crude oil, condensate and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process components used to separate, treat and store crude oil, condensate, natural gas and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells.

Emissions from storage vessels are a result of working, breathing and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

In the Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH), the MACT standards for storage vessels apply only to those with the PFE. Storage vessels with the PFE are defined as storage vessels that contain hydrocarbon liquids that meet the following criteria:

- A stock tank gas to oil ratio (GOR) greater than or equal to 0.31 cubic meters per liter (m^3/liter); and
- An American Petroleum Institute (API) gravity greater than or equal to 40 degrees; and
- An actual annual average hydrocarbon liquid throughput greater than or equal to 79,500 liters per day (liter/day).

Accordingly, there is no emission limit in the existing MACT for storage vessels without the PFE. However, the MACT analysis performed at the time indicates that the MACT floor was based on all storage vessels, not just those vessels with flash emissions. See, *Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category,* (September 23, 1997, Docket A–94–04, Item II–A–07). We, therefore, propose to apply the existing MACT for storage vessels with PFE to all storage vessels (*i.e.,* storage vessels with the PFE, as well as those without the PFE).

3. Definition of Associated Equipment

CAA section 112(n)(4)(A) provides:

> Notwithstanding the provisions of subsection (a), emissions from any oil or gas exploration or production well (with its associated equipment) and emission from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in contiguous area or under common control, to determine whether such units or stations are major sources.

As stated above, the CAA prevents aggregation of HAP emissions from wells and associated equipment in making major source determinations. In the absence of clear guidance in the statute on what constitutes ''associated equipment,'' the EPA sought to define ''associated equipment'' in a way that recognizes the need to implement relief for this industry as Congress intended and that also allow for the appropriate regulation of significant emission points. 64 FR at 32619. Accordingly, in the existing Oil and Natural Gas Production NESHAP (1998 and 1999 NESHAP), the EPA defined ''associated equipment'' to exclude glycol dehydration units and storage vessels with PFE (thus allowing their emissions to be included in determining major source status) because EPA identified these sources as substantial contributors to HAP emissions. *Id.* EPA explained in that NESHAP that, because a single storage vessel with flash emissions may emit several Mg of HAP per year and individual glycol dehydrators may emit above the major source level, storage vessels with PFE and glycol dehydrators are large individual sources of HAP, 63 FR 6288, 6301 (1998). The EPA therefore considered these emission sources substantial contributors to HAP emissions and excluded them from the definition of ''associated equipment.'' 64 FR at 32619. We have recently examined HAP emissions from storage vessels without flash emissions and found that these emissions are significant and comparable to those vessels with flash emissions. For example, one storage vessel with an API gravity of 30 degrees and a GOR of 2.09×10^{-3} m^3/liter with a throughput of 79,500 liter/day had HAP emissions of 9.91 Mg/yr, including 9.45 Mg/yr of n-hexane.

Because storage vessels without the PFE can have significant emissions at levels that are comparable to emissions from storage vessels with the PFE, there is no appreciable difference between storage vessels with the PFE and those without the PFE for purposes of defining ''associated equipment.'' We are, therefore, proposing to amend the associated equipment definition to exclude all storage vessels and not just storage vessels with the PFE.

C. How did we perform the risk assessment and what are the results and proposed decisions?

1. How did we estimate risks posed by the source categories?

The EPA conducted risk assessments that provided estimates for each source in a category of the MIR posed by the HAP emissions, the HI for chronic exposures to HAP with the potential to cause noncancer health effects, and the hazard quotient (HQ) for acute exposures to HAP with the potential to cause noncancer health effects. The assessments also provided estimates of the distribution of cancer risks within the exposed populations, cancer incidence and an evaluation of the potential for adverse environmental effects for each source category. The risk assessments consisted of seven primary steps, as discussed below. The docket for this rulemaking contains the following document which provides more information on the risk assessment inputs and models: *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories.* The methods used to assess risks (as described in the seven primary steps below) are consistent with those peer-reviewed by a panel of the EPA's Science Advisory Board (SAB) in 2009 and described in their peer review report issued in 2010[14]; they are also consistent with the key recommendations contained in that report.

a. Establishing the Nature and Magnitude of Actual Emissions and Identifying the Emissions Release Characteristics

As discussed in section VII.A of this preamble, we used a dataset based on the 2005 NEI as the basis for the risk assessment. In addition to the quality assurance (QA) of the facilities contained in the dataset, we also checked the coordinates of every facility in the dataset through visual observations using tools such as GoogleEarth and ArcView. Where coordinates were found to be incorrect, we identified and corrected them to the extent possible. We also performed QA of the emissions data and release characteristics to ensure there were no outliers.

b. Establishing the Relationship Between Actual Emissions and MACT-Allowable Emissions Levels

The available emissions data in the MACT dataset represent the estimates of mass of emissions actually emitted during the specified annual time period. These ''actual'' emission levels are often lower than the emission levels that a facility might be allowed to emit and still comply with the MACT standards. The emissions level allowed to be emitted by the MACT standards is referred to as the ''MACT-allowable'' emissions level. This represents the highest emissions level that could be emitted by the facility without violating the MACT standards.

We discussed the use of both MACT-allowable and actual emissions in the final Coke Oven Batteries residual risk rule (70 FR 19998–19999, April 15, 2005) and in the proposed and final Hazardous Organic NESHAP residual risk rules (71 FR 34428, June 14, 2006, and 71 FR 76609, December 21, 2006, respectively). In those previous actions, we noted that assessing the risks at the MACT-allowable level is inherently reasonable since these risks reflect the maximum level sources could emit and still comply with national emission standards. But we also explained that it is reasonable to consider actual emissions, where such data are available, in both steps of the risk analysis, in accordance with the Benzene NESHAP. (54 FR 38044, September 14, 1989.)

To estimate emissions at the MACT-allowable level, we developed a ratio of MACT-allowable to actual emissions for each emissions source type in each source category, based on the level of control required by the MACT standards compared to the level of reported actual emissions and available information on the level of control achieved by the emissions controls in use.

c. Conducting Dispersion Modeling, Determining Inhalation Exposures and Estimating Individual and Population Inhalation Risks

Both long-term and short-term inhalation exposure concentrations and health risks from each source in the source categories addressed in this proposal were estimated using the Human Exposure Model (HEM) (Community and Sector HEM–3 version 1.1.0). The HEM–3 performs three primary risk assessment activities: (1) Conducting dispersion modeling to estimate the concentrations of HAP in ambient air, (2) estimating long-term and short-term inhalation exposures to individuals residing within 50 km of the modeled sources and (3) estimating individual and population-level inhalation risks using the exposure estimates and quantitative dose-response information.

The dispersion model used by HEM–3 is AERMOD, which is one of the EPA's preferred models for assessing pollutant concentrations from industrial facilities.[15] To perform the dispersion modeling and to develop the preliminary risk estimates, HEM–3 draws on three data libraries. The first is a library of meteorological data,

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[14] U.S. EPA SAB. *Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies—MACT I Petroleum Refining Sources and Portland Cement Manufacturing,* May 2010.

[15] U.S. EPA. Revision to the *Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions* (70 FR 68218, November 9, 2005).

which is used for dispersion calculations. This library includes 1 year of hourly surface and upper air observations for more than 158 meteorological stations, selected to provide coverage of the United States and Puerto Rico. A second library of United States Census Bureau census block[16] internal point locations and populations provides the basis of human exposure calculations (Census, 2000). In addition, for each census block, the census library includes the elevation and controlling hill height, which are also used in dispersion calculations. A third library of pollutant unit risk factors and other health benchmarks is used to estimate health risks. These risk factors and health benchmarks are the latest values recommended by the EPA for HAP and other toxic air pollutants. These values are available at *http://www.epa.gov/ttn/atw/toxsource/summary.html* and are discussed in more detail later in this section.

In developing the risk assessment for chronic exposures, we used the estimated annual average ambient air concentration of each of the HAP emitted by each source for which we have emissions data in the source category. The air concentrations at each nearby census block centroid were used as a surrogate for the chronic inhalation exposure concentration for all the people who reside in that census block. We calculated the MIR for each facility as the cancer risk associated with a continuous lifetime (24 hours per day, 7 days per week, and 52 weeks per year for a 70-year period) exposure to the maximum concentration at the centroid of an inhabited census block. Individual cancer risks were calculated by multiplying the estimated lifetime exposure to the ambient concentration of each of the HAP (in micrograms per cubic meter) by its unit risk estimate (URE), which is an upper bound estimate of an individual's probability of contracting cancer over a lifetime of exposure to a concentration of 1 microgram of the pollutant per cubic meter of air. For residual risk assessments, we generally use URE values from the EPA's Integrated Risk Information System (IRIS). For carcinogenic pollutants without the EPA IRIS values, we look to other reputable sources of cancer dose-response values, often using California EPA (CalEPA) URE values, where available. In cases where new, scientifically credible dose-response values have been developed in a manner consistent with the EPA guidelines and have undergone a peer review process similar to that used by the EPA, we may use such dose-response values in place of or in addition to other values, if appropriate.

Formaldehyde is a unique case. In 2004, the EPA determined that the Chemical Industry Institute of Toxicology (CIIT) cancer dose-response value for formaldehyde (5.5×10^{-9} per μg/m^3) was based on better science than the IRIS cancer dose-response value (1.3×10^{-5} per μg/m^3) and we switched from using the IRIS value to the CIIT value in risk assessments supporting regulatory actions. However, subsequent research published by the EPA suggests that the CIIT model was not appropriate and in 2010 the EPA returned to using the 1991 IRIS value, which is more health protective.[17] The EPA has been working on revising the formaldehyde IRIS assessment and the National Academy of Sciences (NAS) completed its review of the EPA's draft in May of 2011. EPA is reviewing the public comments and the NAS independent scientific peer review, and the draft IRIS assessment will be revised and the final assessment will be posted on the IRIS database. In the interim, we will present findings using the 1991 IRIS value as a primary estimate, and may also consider other information as the science evolves.

In the case of benzene, the high end of the reported cancer URE range was used in our assessments to provide a conservative estimate of potential cancer risks. Use of the high end of the range provides risk estimates that are approximately 3.5 times higher than use of the equally-plausible low end value. We also evaluated the impact of using the low end of the URE range on our risk results.

We also note that polycyclic organic matter (POM), a carcinogenic HAP with a mutagenic mode of action, is emitted by some of the facilities in these two categories.[18] For this compound group,[19] the age-dependent adjustment factors (ADAF) described in the EPA's *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens*[20] were applied. This adjustment has the effect of increasing the estimated lifetime risks for POM by a factor of 1.6. In addition, although only a small fraction of the total POM emissions were not reported as individual compounds, the EPA expresses carcinogenic potency for compounds in this group in terms of benzo[a]pyrene equivalence, based on evidence that carcinogenic POM has the same mutagenic mechanism of action as benzo[a]pyrene. For this reason, the EPA's Science Policy Council[21] recommends applying the *Supplemental Guidance* to all carcinogenic polycyclic aromatic hydrocarbons for which risk estimates are based on relative potency. Accordingly, we have applied the ADAF to the benzo[a]pyrene equivalent portion of all POM mixtures.

Incremental individual lifetime cancer risks associated with emissions from the source category were estimated as the sum of the risks for each of the carcinogenic HAP (including those classified as carcinogenic to humans, likely to be carcinogenic to humans and suggestive evidence of carcinogenic potential[22]) emitted by the modeled source. Cancer incidence and the distribution of individual cancer risks for the population within 50 km of any source were also estimated for the source category as part of these assessments by summing individual risks. A distance of 50 km is consistent with both the analysis supporting the 1989 Benzene NESHAP (54 FR 38044) and the limitations of Gaussian dispersion models, including AERMOD.

To assess risk of noncancer health effects from chronic exposures, we summed the HQ for each of the HAP that affects a common target organ system to obtain the HI for that target organ system (or target organ-specific HI, TOSHI). The HQ for chronic exposures is the estimated chronic

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[16] A census block is generally the smallest geographic area for which census statistics are tabulated.

[17] For details on the justification for this decision, see the memorandum in the docket from Peter Preuss to Steve Page entitled, *Recommendation for Formaldehyde Inhalation Cancer Risk Values,* January 22, 2010.

[18] U.S. EPA. Performing risk assessments that include carcinogens described in the *Supplemental Guidance* as having a mutagenic mode of action. *Science Policy Council Cancer Guidelines Implementation Work Group Communication II:* Memo from W.H. Farland, dated October 4, 2005.

[19] See the *Risk Assessment for Source Categories* document available in the docket for a list of HAP with a mutagenic mode of action.

[20] U.S. EPA. *Supplemental Guidance for Assessing Early-Life Exposure to Carcinogens.* EPA/630/R–03/003F, 2005. *http://www.epa.gov/ttn/atw/childrens_supplement_final.pdf.*

[21] U.S. EPA. *Science Policy Council Cancer Guidelines Implementation Workgroup Communication II:* Memo from W.H. Farland, dated June 14, 2006.

[22] These classifications also coincide with the terms "known carcinogen, probable carcinogen and possible carcinogen," respectively, which are the terms advocated in the EPA's previous *Guidelines for Carcinogen Risk Assessment,* published in 1986 (51 FR 33992, September 24, 1986). Summing the risks of these individual compounds to obtain the cumulative cancer risks is an approach that was recommended by the EPA's SAB in their 2002 peer review of EPA's NATA entitled, *NATA—Evaluating the National-scale Air Toxics Assessment 1996 Data—an SAB Advisory,* available at: *http://yosemite.epa.gov/sab/sabproduct.nsf/214C6E915BB04E14852570CA007A682C/$File/ecadv02001.pdf.*

exposure divided by the chronic reference level, which is either the EPA reference concentration (RfC), defined as ''an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime,'' or, in cases where an RfC from the EPA's IRIS database is not available, the EPA will utilize the following prioritized sources for our chronic dose-response values: (1) The Agency for Toxic Substances and Disease Registry Minimum Risk Level, which is defined as ''an estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects (other than cancer) over a specified duration of exposure''; (2) the CalEPA Chronic Reference Exposure Level (REL), which is defined as ''the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration''; and (3), as noted above, in cases where scientifically credible dose-response values have been developed in a manner consistent with the EPA guidelines and have undergone a peer review process similar to that used by the EPA, we may use those dose-response values in place of or in concert with other values.

Screening estimates of acute exposures and risks were also evaluated for each of the HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids), assuming that a person is located at this spot at a time when both the peak (hourly) emission rate and worst-case dispersion conditions (1991 calendar year data) occur. The acute HQ is the estimated acute exposure divided by the acute dose-response value. In each case, acute HQ values were calculated using best available, short-term dose-response values. These acute dose-response values, which are described below, include the acute REL, acute exposure guideline levels (AEGL) and emergency response planning guidelines (ERPG) for 1-hour exposure durations. As discussed below, we used conservative assumptions for emission rates, meteorology and exposure location for our acute analysis.

As described in the CalEPA's *Air Toxics Hot Spots Program Risk Assessment Guidelines, Part I, The Determination of Acute Reference Exposure Levels for Airborne Toxicants,* an acute REL value (*http://www.oehha.ca.gov/air/pdf/acuterel.pdf*) is defined as ''the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration.'' Acute REL values are based on the most sensitive, relevant, adverse health effect reported in the medical and toxicological literature. Acute REL values are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety. Since margins of safety are incorporated to address data gaps and uncertainties, exceeding the acute REL does not automatically indicate an adverse health impact.

AEGL values were derived in response to recommendations from the National Research Council (NRC). As described in *Standing Operating Procedures (SOP) of the National Advisory Committee on Acute Exposure Guideline Levels for Hazardous Substances (http://www.epa.gov/opptintr/aegl/pubs/sop.pdf),*[23] ''the NRC's previous name for acute exposure levels—community emergency exposure levels—was replaced by the term AEGL to reflect the broad application of these values to planning, response, and prevention in the community, the workplace, transportation, the military, and the remediation of Superfund sites.'' This document also states that AEGL values ''represent threshold exposure limits for the general public and are applicable to emergency exposures ranging from 10 minutes to eight hours.'' The document lays out the purpose and objectives of AEGL by stating (page 21) that ''the primary purpose of the AEGL program and the National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances is to develop guideline levels for once-in-a-lifetime, short-term exposures to airborne concentrations of acutely toxic, high-priority chemicals.'' In detailing the intended application of AEGL values, the document states (page 31) that ''[i]t is anticipated that the AEGL values will be used for regulatory and nonregulatory purposes by U.S. Federal and state agencies and possibly the international community in conjunction with chemical emergency response, planning, and prevention programs. More specifically, the AEGL values will be used for conducting various risk assessments to aid in the development of emergency preparedness and prevention plans, as well as real-time emergency response actions, for accidental chemical releases at fixed facilities and from transport carriers.''

The AEGL–1 value is then specifically defined as ''the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic nonsensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.'' The document also notes (page 3) that, ''Airborne concentrations below AEGL–1 represent exposure levels that can produce mild and progressively increasing but transient and nondisabling odor, taste, and sensory irritation or certain asymptomatic, nonsensory effects.'' Similarly, the document defines AEGL–2 values as ''the airborne concentration (expressed as ppm or mg/m^3) of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.''

ERPG values are derived for use in emergency response, as described in the American Industrial Hygiene Association's document entitled, *Emergency Response Planning Guidelines (ERPG) Procedures and Responsibilities* (*http://www.aiha.org/1documents/committees/ERPSOPs2006.pdf*) which states that, ''Emergency Response Planning Guidelines were developed for emergency planning and are intended as health based guideline concentrations for single exposures to chemicals.''[24] The ERPG–1 value is defined as ''the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing other than mild transient adverse health effects or without perceiving a clearly defined, objectionable odor.'' Similarly, the ERPG–2 value is defined as ''the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.''

As can be seen from the definitions above, the AEGL and ERPG values include the similarly-defined severity levels 1 and 2. For many chemicals, a severity level 1 value AEGL or ERPG has not been developed; in these instances, higher severity level AEGL–2 or ERPG–2 values are compared to our modeled

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[23] NAS, 2001. *Standing Operating Procedures for Developing Acute Exposure Levels for Hazardous Chemicals,* page 2.

[24] *ERP Committee Procedures and Responsibilities.* November 1, 2006. American Industrial Hygiene Association.

exposure levels to screen for potential acute concerns.

Acute REL values for 1-hour exposure durations are typically lower than their corresponding AEGL–1 and ERPG–1 values. Even though their definitions are slightly different, AEGL–1 values are often the same as the corresponding ERPG–1 values, and AEGL–2 values are often equal to ERPG–2 values. Maximum HQ values from our acute screening risk assessments typically result when basing them on the acute REL value for a particular pollutant. In cases where our maximum acute HQ value exceeds 1, we also report the HQ value based on the next highest acute dose-response value (usually the AEGL–1 and/or the ERPG–1 value).

To develop screening estimates of acute exposures, we developed estimates of maximum hourly emission rates by multiplying the average actual annual hourly emission rates by a factor to cover routinely variable emissions. We chose the factor based on process knowledge and engineering judgment and with awareness of a Texas study of short-term emissions variability, which showed that most peak emission events, in a heavily-industrialized 4-county area (Harris, Galveston, Chambers and Brazoria Counties, Texas) were less than twice the annual average hourly emission rate. The highest peak emission event was 74 times the annual average hourly emission rate, and the 99th percentile ratio of peak hourly emission rate to the annual average hourly emission rate was 9.[25] This analysis is provided in Appendix 4 of the *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories,* which is available in the docket for this action. Considering this analysis, unless specific process knowledge or data are available to provide an alternate value, to account for more than 99 percent of the peak hourly emissions, we apply a conservative screening multiplication factor of 10 to the average annual hourly emission rate in these acute exposure screening assessments. The factor of 10 was used for both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories.

In cases where acute HQ values from the screening step were less than or equal to 1, acute impacts were deemed negligible and no further analysis was performed. In cases where an acute HQ from the screening step was greater than 1, additional site-specific data were considered to develop a more refined estimate of the potential for acute impacts of concern. The data refinements employed for these source categories consisted of using the site-specific facility layout to distinguish facility property from an area where the public could be exposed. These refinements are discussed in the draft risk assessment document, which is available in the docket for each of these source categories. Ideally, we would prefer to have continuous measurements over time to see how the emissions vary by each hour over an entire year. Having a frequency distribution of hourly emission rates over a year would allow us to perform a probabilistic analysis to estimate potential threshold exceedances and their frequency of occurrence. Such an evaluation could include a more complete statistical treatment of the key parameters and elements adopted in this screening analysis. However, we recognize that having this level of data is rare, hence our use of the multiplier approach.

To better characterize the potential health risks associated with estimated acute exposures to HAP, and in response to a key recommendation from the SAB's peer review of the EPA's RTR risk assessment methodologies,[26] we generally examine a wider range of available acute health metrics than we do for our chronic risk assessments. This is in response to the SAB's acknowledgement that there are generally more data gaps and inconsistencies in acute reference values than there are in chronic reference values. Comparisons of the estimated maximum off-site 1-hour exposure levels are not typically made to occupational levels for the purpose of characterizing public health risks in RTR assessments. This is because they are developed for working age adults and are not generally considered protective for the general public. We note that occupational ceiling values are, for most chemicals, set at levels higher than a 1-hour AEGL–1.

As discussed in section VII.C.2 of this preamble, the maximum estimated worst-case 1-hour exposure to benzene outside the facility fence line for a facility in either source category is 12 mg/m^3. This estimated exposure exceeds the 6-hour REL by a factor of 9 (HQ_{REL} = 9), but is significantly below the 1-hour AEGL–1 (HQ_{AEGL-1} = 0.07). Although this worst-case exposure estimate does not exceed the AEGL–1, we note here that it slightly exceeds workplace ceiling level guidelines designed to protect the worker population for short duration (<15 minute) increases in exposure to benzene, as discussed below. The occupational short-term exposure limit (STEL) standard for benzene developed by the Occupational Safety and Health Administration is 16 mg/m^3, "as averaged over any 15-minute period."[27] Occupational guideline STEL for exposures to benzene have also been developed by the American Conference of Governmental Industrial Hygienists (ACGIH)[28] for less than 15 minutes[29] (ACGIH threshold limit value (TLV)-STEL value of 8.0 mg/m^3), and by the National Institute for Occupational Safety and Health (NIOSH)[30] "for any 15 minute period in a work day" (NIOSH REL–STEL of 3.2 mg/m^3). These shorter duration occupational values indicate potential concerns regarding health effects at exposure levels below the 1-hour AEGL–1 value. We solicit comment on the use of the occupational values described above in the interpretation of these worst-case acute screening exposure estimates.

d. Conducting Multi-Pathway Exposure and Risk Modeling

The potential for significant human health risks due to exposures via routes other than inhalation (*i.e.,* multi-pathway exposures) and the potential for adverse environmental impacts were evaluated in a three-step process. In the first step, we determined whether any facilities emitted any HAP known to be PB–HAP (HAP known to be persistent and bio-accumulative) in the environment. There are 14 PB–HAP compounds or compound classes identified for this screening in the EPA's *Air Toxics Risk Assessment Library* (available at *http://www.epa.gov/ttn/fera/risk_atra_vol1.html*). They are cadmium compounds, chlordane, chlorinated dibenzodioxins and furans,

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[25] See *http://www.tceq.state.tx.us/compliance/field_ops/eer/index.html* or docket to access the source of these data.

[26] The SAB peer review of RTR Risk Assessment Methodologies is available at: *http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.*

[27] 29 CFR 1910.1028, Benzene. Available online at *http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=10042.*

[28] ACGIH (2001) Benzene. In *Documentation of the TLVs® and BEIs® with Other Worldwide Occupational Exposure Values.* ACGIH, 1300 Kemper Meadow Drive, Cincinnati, OH 45240 (ISBN: 978–1–882417–74–2) and available online at *http://www.acgih.org.*

[29] The ACGIH definition of a TLV–STEL states that "Exposures above the TLV–TWA up to the TLV–STEL should be less than 15 minutes, should occur no more than four times per day, and there should be at least 60 minutes between successive exposures in this range."

[30] NIOSH. *Occupational Safety and Health Guideline for Benzene; http://www.cdc.gov/niosh/74-137.html.*

dichlorodiphenyldichloroethylene, heptachlor, hexachlorobenzene, hexachlorocyclohexane, lead compounds, mercury compounds, methoxychlor, polychlorinated biphenyls, POM, toxaphene and trifluralin.

Since one or more of these PB–HAP are emitted by at least one facility in both source categories, we proceeded to the second step of the evaluation. In this step, we determined whether the facility-specific emission rates of each of the emitted PB–HAP were large enough to create the potential for significant non-inhalation human or environmental risks under reasonable worst-case conditions. To facilitate this step, we have developed emission rate thresholds for each PB–HAP using a hypothetical worst-case screening exposure scenario developed for use in conjunction with the EPA's TRIM.FaTE model. The hypothetical screening scenario was subjected to a sensitivity analysis to ensure that its key design parameters were established such that environmental media concentrations were not underestimated (*i.e.,* to minimize the occurrence of false negatives or results that suggest that risks might be acceptable when, in fact, actual risks are high) and to also minimize the occurrence of false positives for human health endpoints. We call this application of the TRIM.FaTE model TRIM–Screen. The facility-specific emission rates of each of the PB–HAP in each source category were compared to the TRIM–Screen emission threshold values for each of the PB–HAP identified in the source category datasets to assess the potential for significant human health risks or environmental risks via non-inhalation pathways.

There was only one facility in the Natural Gas Transmission and Storage source category with reported emissions of PB–HAP, and the emission rates were less than the emission threshold values. There were 29 facilities in the Oil and Natural Gas Production source category with reported emissions of PB–HAP, and one of these had emission rates greater than the emission threshold values. In this case, the emission threshold value for POM was exceeded by a factor of 6. For POM, dairy, vegetables and fruits were the three most dominant exposure pathways driving human exposures in the hypothetical screening exposure scenario. The single facility with emissions exceeding the emission threshold value for POM is located in a highly industrialized area. Therefore, since the exposure pathways which would drive high human exposure are not locally available, multi-pathway exposures and environmental risks were deemed negligible, and no further analysis was performed. For further information on the multi-pathway analysis approach, see the residual risk documentation.

e. Assessing Risks Considering Emissions Control Options

In addition to assessing baseline inhalation risks and screening for potential multi-pathway risks, where appropriate, we also estimated risks considering the potential emission reductions that would be achieved by the particular control options under consideration. In these cases, the expected emissions reductions were applied to the specific HAP and emissions sources in the source category dataset to develop corresponding estimates of risk reductions.

f. Conducting Other Risk-Related Analyses: Facility-Wide Assessments

To put the source category risks in context, we also examined the risks from the entire ''facility,'' where the facility includes all HAP-emitting operations within a contiguous area and under common control. In other words, for each facility that includes one or more sources from one of the source categories under review, we examined the HAP emissions not only from the source category of interest, but also from all other emission sources at the facility. The emissions data for generating these ''facility-wide'' risks were also obtained from the 2005 NEI. For every facility included in the MACT database, we also retrieved emissions data and release characteristics for all other emission sources at the same facility. We estimated the risks due to the inhalation of HAP that are emitted ''facility-wide'' for the populations residing within 50 km of each facility, consistent with the methods used for the source category analysis described above. For these facility-wide risk analyses, the modeled source category risks were compared to the facility-wide risks to determine the portion of facility-wide risks that could be attributed to the source categories addressed in this proposal. We specifically examined the facilities associated with the highest estimates of risk and determined the percentage of that risk attributable to the source category of interest. The risk documentation available through the docket for this action provides the methodology and the results of the facility-wide analyses for each source category.

g. Conducting Other Analyses: Demographic Analysis

To examine the potential for any environmental justice (EJ) issues that might be associated with each source category, we performed a demographic analysis of population risk. In this analysis, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories are located. The development of demographic analyses to inform the consideration of EJ issues in the EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this rulemaking to inform the consideration of potential EJ issues and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve the utility of such analyses for future rulemakings.

For the demographic analyses, we focus on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examine the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source-category-specific technical reports in the docket for both source categories covered in this proposal.

The basis for the risk values used in these analyses were the modeling results based on actual emissions levels obtained from the HEM–3 model described above. The risk values for each census block were linked to a database of information from the 2000 Decennial census that includes data on race and ethnicity, age distributions, poverty status, household incomes and education level. The Census Department Landview® database was the source of the data on race and ethnicity and the data on age distributions, poverty status, household incomes and education level were obtained from the 2000 Census of Population and Housing Summary File 3 Long Form. While race and ethnicity census data are available at the census block level, the age and income census data are only available at the census block group level (which includes an average of 26 blocks or an average of 1,350 people). Where census data are available at the block group level, but not the block level, we assumed that all census blocks within the block group have the same distribution of ages and incomes as the block group.

For each source category, we focused on those census blocks where source category risk results show estimated lifetime inhalation cancer risks above 1-in-1 million or chronic noncancer indices above 1 and determined the relative percentage of different racial and ethnic groups, different age groups, adults with and without a high school diploma, people living in households below the national median income and for people living below the poverty line within those census blocks. The specific census population categories studied include:

- Total population
- White
- African American (or Black)
- Native Americans
- Other races and multiracial
- Hispanic or Latino
- Children 18 years of age and under
- Adults 19 to 64 years of age
- Adults 65 years of age and over
- Adults without a high school diploma
- Households earning under the national median income
- People living below the poverty line

It should be noted that these categories overlap in some instances, resulting in some populations being counted in more than one category (*e.g.,* other races and multiracial and Hispanic). In addition, while not a specific census population category, we also examined risks to ''Minorities,'' a classification which is defined for these purposes as all race population categories except white.

For further information about risks to the populations located near the facilities in these source categories, we also evaluated the estimated distribution of inhalation cancer and chronic noncancer risks associated with the HAP emissions from all the emissions sources at the facility (*i.e.,* facility-wide). This analysis used the facility-wide RTR modeling results and the census data described above.

The methodology and the results of the demographic analyses for each source category are included in a source-category-specific technical report for each of the categories, which are available in the docket for this action.

h. Considering Uncertainties in Risk Assessment

Uncertainty and the potential for bias are inherent in all risk assessments, including those performed for the source categories addressed in this proposal. Although uncertainty exists, we believe that our approach, which used conservative tools and assumptions, ensures that our decisions are health-protective. A brief discussion of the uncertainties in the emissions datasets, dispersion modeling, inhalation exposure estimates and dose-response relationships follows below. A more thorough discussion of these uncertainties is included in the risk assessment documentation (referenced earlier) available in the docket for this action.

i. Uncertainties in the Emissions Datasets

Although the development of the MACT dataset involved QA/quality control processes, the accuracy of emissions values will vary depending on the source of the data, the degree to which data are incomplete or missing, the degree to which assumptions made to complete the datasets are inaccurate, errors in estimating emissions values and other factors. The emission estimates considered in this analysis generally are annual totals for certain years that do not reflect short-term fluctuations during the course of a year or variations from year to year.

The estimates of peak hourly emission rates for the acute effects screening assessment were based on a multiplication factor of 10 applied to the average annual hourly emission rate, which is intended to account for emission fluctuations due to normal facility operations. Additionally, although we believe that we have data for most facilities in these two source categories in our RTR dataset, our dataset may not include data for all existing facilities. Moreover, there are uncertainties with regard to the identification of sources as major or area in the NEI for these source categories.

ii. Uncertainties in Dispersion Modeling

While the analysis employed the EPA's recommended regulatory dispersion model, AERMOD, we recognize that there is uncertainty in ambient concentration estimates associated with any model, including AERMOD. In circumstances where we had to choose between various model options, where possible, model options (*e.g.,* rural/urban, plume depletion, chemistry) were selected to provide an overestimate of ambient air concentrations of the HAP rather than underestimates. However, because of practicality and data limitation reasons, some factors (*e.g.,* meteorology, building downwash) have the potential in some situations to overestimate or underestimate ambient impacts. For example, meteorological data were taken from a single year (1991) and facility locations can be a significant distance from the site where these data were taken. Despite these uncertainties, we believe that at off-site locations and census block centroids, the approach considered in the dispersion modeling analysis should generally yield overestimates of ambient HAP concentrations.

iii. Uncertainties in Inhalation Exposure

The effects of human mobility on exposures were not included in the assessment. Specifically, short-term mobility and long-term mobility between census blocks in the modeling domain were not considered.[31] The assumption of not considering short or long-term population mobility does not bias the estimate of the theoretical MIR, nor does it affect the estimate of cancer incidence since the total population number remains the same. It does, however, affect the shape of the distribution of individual risks across the affected population, shifting it toward higher estimated individual risks at the upper end and reducing the number of people estimated to be at lower risks, thereby increasing the estimated number of people at specific risk levels.

In addition, the assessment predicted the chronic exposures at the centroid of each populated census block as surrogates for the exposure concentrations for all people living in that block. Using the census block centroid to predict chronic exposures tends to over-predict exposures for people in the census block who live further from the facility, and under-predict exposures for people in the census block who live closer to the facility. Thus, using the census block centroid to predict chronic exposures may lead to a potential understatement or overstatement of the true maximum impact, but is an unbiased estimate of average risk and incidence.

The assessments evaluate the cancer inhalation risks associated with continuous pollutant exposures over a 70-year period, which is the assumed lifetime of an individual. In reality, both the length of time that modeled emissions sources at facilities actually operate (*i.e.,* more or less than 70 years), and the domestic growth or decline of the modeled industry (*i.e.,* the increase

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[31] Short-term mobility is movement from one micro-environment to another over the course of hours or days. Long-term mobility is movement from one residence to another over the course of a lifetime.

or decrease in the number or size of United States facilities), will influence the risks posed by a given source category. Depending on the characteristics of the industry, these factors will, in most cases, result in an overestimate both in individual risk levels and in the total estimated number of cancer cases. However, in rare cases, where a facility maintains or increases its emission levels beyond 70 years, residents live beyond 70 years at the same location, and the residents spend most of their days at that location, then the risks could potentially be underestimated. Annual cancer incidence estimates from exposures to emissions from these sources would not be affected by uncertainty in the length of time emissions sources operate.

The exposure estimates used in these analyses assume chronic exposures to ambient levels of pollutants. Because most people spend the majority of their time indoors, actual exposures may not be as high, depending on the characteristics of the pollutants modeled. For many of the HAP, indoor levels are roughly equivalent to ambient levels, but for very reactive pollutants or larger particles, these levels are typically lower. This factor has the potential to result in an overstatement of 25 to 30 percent of exposures.[32]

In addition to the uncertainties highlighted above, there are several factors specific to the acute exposure assessment that should be highlighted. The accuracy of an acute inhalation exposure assessment depends on the simultaneous occurrence of independent factors that may vary greatly, such as hourly emissions rates, meteorology, and human activity patterns. In this assessment, we assume that individuals remain for 1 hour at the point of maximum ambient concentration as determined by the co-occurrence of peak emissions and worst-case meteorological conditions. These assumptions would tend to overestimate actual exposures since it is unlikely that a person would be located at the point of maximum exposure during the time of worst-case impact.

iv. Uncertainties in Dose-Response Relationships

There are uncertainties inherent in the development of the dose-response values used in our risk assessments for cancer effects from chronic exposures and noncancer effects from both chronic and acute exposures. Some uncertainties may be considered quantitatively, and others generally are expressed in qualitative terms. We note as a preface to this discussion a point on dose-response uncertainty that is brought out in the *EPA 2005 Cancer Guidelines;* namely, that ''the primary goal of the EPA actions is protection of human health; accordingly, as an Agency policy, risk assessment procedures, including default options that are used in the absence of scientific data to the contrary, should be health protective.'' (*EPA 2005 Cancer Guidelines,* pages 1–7.) This is the approach followed here as summarized in the next several paragraphs. A complete detailed discussion of uncertainties and variability in dose-response relationships is given in the residual risk documentation, which is available in the docket for this action.

Cancer URE values used in our risk assessments are those that have been developed to generally provide an upper bound estimate of risk. That is, they represent a ''plausible upper limit to the true value of a quantity'' (although this is usually not a true statistical confidence limit).[33] In some circumstances, the true risk could be as low as zero; however, in other circumstances, the risk could also be greater.[34] When developing an upper bound estimate of risk and to provide risk values that do not underestimate risk, health-protective default approaches are generally used. To err on the side of ensuring adequate health-protection, the EPA typically uses the upper bound estimates rather than lower bound or central tendency estimates in our risk assessments, an approach that may have limitations for other uses (*e.g.,* priority-setting or expected benefits analysis).

Chronic noncancer reference (RfC and reference dose (RfD)) values represent chronic exposure levels that are intended to be health-protective levels. Specifically, these values provide an estimate (with uncertainty spanning perhaps an order of magnitude) of daily oral exposure (RfD) or of a continuous inhalation exposure (RfC) to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. To derive values that are intended to be ''without appreciable risk,'' the methodology relies upon an uncertainty factor (UF) approach (U.S. EPA, 1993, 1994) which includes consideration of both uncertainty and variability. When there are gaps in the available information, UF are applied to derive reference values that are intended to protect against appreciable risk of deleterious effects. The UF are commonly default values,[35] *e.g.,* factors of 10 or 3, used in the absence of compound-specific data; where data are available, UF may also be developed using compound-specific information. When data are limited, more assumptions are needed and more UF are used. Thus, there may be a greater tendency to overestimate risk in the sense that further study might support development of reference values that are higher (*i.e.,* less potent) because fewer default assumptions are needed. However, for some pollutants, it is possible that risks may be underestimated. While collectively termed ''uncertainty factor,'' these factors account for a number of different quantitative considerations when using observed animal (usually rodent) or human toxicity data in the development of the RfC. The UF are intended to account for: (1) Variation in susceptibility among the members of the human population (*i.e.,* inter-individual variability); (2) uncertainty in extrapolating from experimental animal data to humans (*i.e.,* interspecies differences); (3) uncertainty in extrapolating from data obtained in a study with less-than-lifetime exposure (*i.e.,* extrapolating from sub-chronic to chronic exposure); (4) uncertainty in extrapolating the observed data to obtain an estimate of the exposure associated with no adverse effects; and (5) uncertainty when the database is incomplete or there are problems with the applicability of available studies. Many of the UF used to account for variability and uncertainty in the development of acute reference values

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[32] U.S. EPA. *National-Scale Air Toxics Assessment for 1996.* (EPA 453/R–01–003; January 2001; page 85.)

[33] IRIS glossary (*http://www.epa.gov/NCEA/iris/help_gloss.htm*).

[34] An exception to this is the URE for benzene, which is considered to cover a range of values, each end of which is considered to be equally plausible and which is based on maximum likelihood estimates.

[35] According to the NRC report, *Science and Judgment in Risk Assessment* (NRC, 1994) ''[Default] options are generic approaches, based on general scientific knowledge and policy judgment, that are applied to various elements of the risk assessment process when the correct scientific model is unknown or uncertain.'' The 1983 NRC report, *Risk Assessment in the Federal Government: Managing the Process,* defined default option as ''the option chosen on the basis of risk assessment policy that appears to be the best choice in the absence of data to the contrary'' (NRC, 1983a, p. 63). Therefore, default options are not rules that bind the Agency; rather, the Agency may depart from them in evaluating the risks posed by a specific substance when it believes this to be appropriate. In keeping with EPA's goal of protecting public health and the environment, default assumptions are used to ensure that risk to chemicals is not underestimated (although defaults are not intended to overtly overestimate risk). See EPA, 2004, *An Examination of EPA Risk Assessment Principles and Practices,* EPA/100/B–04/001 available at: *http://www.epa.gov/osa/pdfs/ratf-final.pdf.*

are quite similar to those developed for chronic durations, but they more often use individual UF values that may be less than 10. UF are applied based on chemical-specific or health effect-specific information (*e.g.,* simple irritation effects do not vary appreciably between human individuals, hence a value of 3 is typically used), or based on the purpose for the reference value (see the following paragraph). The UF applied in acute reference value derivation include: (1) Heterogeneity among humans; (2) uncertainty in extrapolating from animals to humans; (3) uncertainty in lowest observed adverse effect (exposure) level to no observed adverse effect (exposure) level adjustments; and (4) uncertainty in accounting for an incomplete database on toxic effects of potential concern. Additional adjustments are often applied to account for uncertainty in extrapolation from observations at one exposure duration (*e.g.,* 4 hours) to derive an acute reference value at another exposure duration (*e.g.,* 1 hour).

Not all acute reference values are developed for the same purpose and care must be taken when interpreting the results of an acute assessment of human health effects relative to the reference value or values being exceeded. Where relevant to the estimated exposures, the lack of short-term dose-response values at different levels of severity should be factored into the risk characterization as potential uncertainties.

Although every effort is made to identify peer-reviewed reference values for cancer and noncancer effects for all pollutants emitted by the sources included in this assessment, some HAP continue to have no reference values for cancer or chronic noncancer or acute effects. Since exposures to these pollutants cannot be included in a quantitative risk estimate, an understatement of risk for these pollutants at environmental exposure levels is possible. For a group of compounds that are either unspeciated or do not have reference values for every individual compound (*e.g.,* glycol ethers), we conservatively use the most protective reference value to estimate risk from individual compounds in the group of compounds.

Additionally, chronic reference values for several of the compounds included in this assessment are currently under the EPA IRIS review and revised assessments may determine that these pollutants are more or less potent than the current value. We may re-evaluate residual risks for the final rulemaking if these reviews are completed prior to our taking final action for these source categories and a dose-response metric changes enough to indicate that the risk assessment supporting this notice may significantly understate human health risk.

v. Uncertainties in the Multi-Pathway and Environmental Effects Assessment

We generally assume that when exposure levels are not anticipated to adversely affect human health, they also are not anticipated to adversely affect the environment. For each source category, we generally rely on the site-specific levels of PB–HAP emissions to determine whether a full assessment of the multi-pathway and environmental effects is necessary. As discussed above, we conclude that the potential for these types of impacts is low for these source categories.

vi. Uncertainties in the Facility-Wide Risk Assessment

Given that the same general analytical approach and the same models were used to generate facility-wide risk results as were used to generate the source category risk results, the same types of uncertainties discussed above for our source category risk assessments apply to the facility-wide risk assessments. Additionally, the degree of uncertainty associated with facility-wide emissions and risks is likely greater because we generally have not conducted a thorough engineering review of emissions data for source categories not currently undergoing an RTR review.

vii. Uncertainties in the Demographic Analysis

Our analysis of the distribution of risks across various demographic groups is subject to the typical uncertainties associated with census data (*e.g.,* errors in filling out and transcribing census forms), as well as the additional uncertainties associated with the extrapolation of census-block group data (*e.g.,* income level and education level) down to the census block level.

2. What are the results and proposed decisions from the risk review for the Oil and Natural Gas Production source category?

a. Results of the Risk Assessments and Analyses

We conducted an inhalation risk assessment for the Oil and Natural Gas Production source category. We also conducted an assessment of facility-wide risk. Details of the risk assessments and analyses can be found in the residual risk documentation, which is available in the docket for this action. For informational purposes and to examine the potential for any EJ issues that might be associated with each source category, we performed a demographic analysis of population risks.

i. Inhalation Risk Assessment Results

Table 2 provides an overall summary of the results of the inhalation risk assessment.

TABLE 2—OIL AND NATURAL GAS PRODUCTION INHALATION RISK ASSESSMENT RESULTS

Number of facilities [1]	Maximum individual cancer risk (in 1 million) [2]		Estimated population at risk ≥ 1-in-1 million	Estimated annual cancer incidence (cases per year)	Maximum chronic noncancer TOSHI [4]		Maximum off-site acute noncancer HQ [5]
	Actual emissions level	Allowable emissions level			Actual emissions level	Allowable emissions level	
990	40	100–400 [3]	160,000 [3]	0.007–0.02 [3]	0.1	0.7	HQ_{REL} = 9 (benzene) HQ_{AEGL-1} = 0.07 (benzene)

[1] Number of facilities evaluated in the risk analysis.

[2] Estimated maximum individual excess lifetime cancer risk.

[3] The EPA IRIS assessment for benzene provides a range of equally-plausible URE (2.2E–06 to 7.8E–06 per ug/m3), giving rise to ranges for the estimates of cancer MIR and cancer incidence. Estimated population values are not scalable with benzene URE range, but would be lower using the lower end of the URE range.

[4] Maximum TOSHI. The target organ with the highest TOSHI for the Oil and Natural Gas Production source category is the respiratory system.

[5] The maximum estimated acute exposure concentration was divided by available short-term dose-response values to develop an array of HQ values.

As shown in Table 2, the results of the inhalation risk assessment performed using actual emissions data indicate the maximum lifetime individual cancer risk could be as high as 40-in-1 million, with POM driving the highest risk, and benzene driving risks overall. The total estimated cancer incidence from this source category is 0.02 excess cancer cases per year (0.007 excess cancer cases per year based on the lower end of the benzene URE range), or one case in every 50 years. Approximately 160,000 people are estimated to have cancer risks at or above 1-in-1 million as a result of the emissions from 89 facilities (use of the lower end of the benzene URE range would further reduce this population estimate). The maximum chronic non-cancer TOSHI value for the source category could be up to 0.1 from emissions of naphthalene, indicating no significant potential for chronic noncancer impacts.

As explained above, our analysis of potential differences between actual emission levels and emissions allowable under the oil and natural gas production MACT standard indicate that MACT-allowable emission levels may be up to 50 times greater than actual emission levels. Considering this difference, the risk results from the inhalation risk assessment indicate the maximum lifetime individual cancer risk could be as high as 400-in-1 million (100-in-1 million based on the lower end of the benzene URE range) and the maximum chronic noncancer TOSHI value could be as high as 0.7 at the MACT-allowable emissions level.

ii. Facility-Wide Risk Assessment Results

A facility-wide risk analysis was also conducted based on actual emissions levels. Table 3 displays the results of the facility-wide risk assessment. For detailed facility-specific results, see Table 2 of Appendix 6 of the risk document in the docket for this rulemaking.

TABLE 3—OIL AND NATURAL GAS PRODUCTION FACILITY-WIDE RISK ASSESSMENT RESULTS

Number of facilities analyzed	990
Cancer Risk:	
Estimated maximum facility-wide individual cancer risk (in 1 million)	100
Number of facilities with estimated facility-wide individual cancer risk of 100-in-1 million or more	1
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide individual cancer risks of 100-in-1 million or more	0
Number of facilities with facility-wide individual cancer risk of 1-in-1 million or more	140
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide individual cancer risk of 1-in-1 million or more	85
Chronic Noncancer Risk:	
Maximum facility-wide chronic noncancer TOSHI	9
Number of facilities with facility-wide maximum noncancer TOSHI greater than 1	10
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide maximum noncancer TOSHI of 1 or more	0

The facility-wide MIR from all HAP emissions at a facility that contains sources subject to the oil and natural gas production MACT standards is estimated to be 100-in-1 million, based on actual emissions. Of the 990 facilities included in this analysis, only one has a facility-wide MIR of 100-in-1 million. At this facility, oil and natural gas production accounts for less than 2 percent of the total facility-wide risk. Nickel emissions from oil-fired boilers and formaldehyde emissions from reciprocating internal combustion engines (RICE) contribute essentially all the facility-wide risks at this facility, with over 80 percent of the risk attributed to the nickel emissions.[36] There are 140 facilities with facility-wide MIR of 1-in-1 million or greater. Of these facilities, 85 have oil and natural gas production operations that contribute greater than 50 percent to the facility-wide risks. As discussed above, we are proposing MACT standards for BTEX emissions from small glycol dehydrators in this action. These standards would reduce the risk from benzene emissions at facilities with oil and gas production. Formaldehyde emissions will be assessed under future RTR for RICE.

The facility-wide maximum individual chronic noncancer TOSHI is estimated to be 9 based on actual emissions. Of the 990 facilities included in this analysis, 10 have facility-wide maximum chronic noncancer TOSHI values greater than 1. Of these facilities, none had oil and natural gas production operations that contributed greater than 50 percent to these facility-wide risks. The chronic noncancer risks at these 10 facilities are primarily driven by acrolein emissions from RICE.

iii. Demographic Risk Analysis Results

The results of the demographic analyses performed to investigate the distribution of cancer risks at or above 1-in-1 million among the surrounding population are summarized in Table 4 below. These results, for various demographic groups, are based on actual emissions levels for the population living within 50 km of the facilities.

TABLE 4—OIL AND NATURAL GAS PRODUCTION DEMOGRAPHIC RISK ANALYSIS RESULTS

	Nationwide	Population with cancer risk at or above 1-in-1 million due to	
		Source category HAP emissions	Facility-wide HAP emissions
Total Population	285,000,000	160,000	597,000

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[36] We note that there is an ongoing IRIS reassessment for formaldehyde, and that future RTR risk assessments will use the cancer potency for formaldehyde that results from that reassessment. As a result, the current results may not match those of future assessments.

TABLE 4—OIL AND NATURAL GAS PRODUCTION DEMOGRAPHIC RISK ANALYSIS RESULTS—Continued

	Nationwide	Population with cancer risk at or above 1-in-1 million due to	
		Source category HAP emissions	Facility-wide HAP emissions
Race by Percent			
White	75	62	61
All Other Races	25	38	39
Race by Percent			
White	75	62	61
African American	12	12	8
Native American	0.9	0.7	1.3
Other and Multiracial	12	25	30
Ethnicity by Percent			
Hispanic	14	22	34
Non-Hispanic	86	78	66
Income by Percent			
Below Poverty Level	13	14	19
Above Poverty Level	87	86	81
Education by Percent			
Over 25 and without High School Diploma	13	10	16
Over 25 and with a High School Diploma	87	90	84

The results of the Oil and Natural Gas Production source category demographic analysis indicate that there are approximately 160,000 people exposed to a cancer risk at or above 1-in-1 million due to emissions from the source category, including an estimated 38 percent that are classified as minority (listed as ''All Other Races'' in the table above). Of the 160,000 people with estimated cancer risks at or above 1-in-1 million from the source category, 25 percent are in the ''Other and Multiracial'' demographic group, 22 percent are in the ''Hispanic or Latino'' demographic group, and 14 percent are in the ''Below Poverty Level'' demographic group, results which are 13, 8 and 1 percentage points higher, respectively, than the respective percentages for these demographic groups across the United States. The percentages for the other demographic groups are lower than their respective nationwide percentages. The table also shows that there are approximately 597,000 people exposed to an estimated cancer risk at or above 1-in-1 million due to facility-wide emissions, including 30 percent in the ''Other and Multiracial'' demographic group, 34 percent in the ''Hispanic or Latino'' demographic group, 1.3 percent in the ''Native American'' demographic group and 16 percent in the ''Over 25 and without High School Diploma'' demographic group, results which are 18, 2, 0.4 and 3 percentage points higher than the percentages for these demographic groups across the United States, respectively. The percentages for the other demographic groups are lower than their respective nationwide percentages.

b. What are the proposed risk decisions for the Oil and Natural Gas Production source category?

i. Risk Acceptability

In the risk analysis we performed for this source category, pursuant to CAA section 112(f)(2), we considered the available health information—the MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer HI; the maximum acute noncancer hazard; the extent of noncancer risks; the potential for adverse environmental effects; and distribution of risks in the exposed population; and risk estimation uncertainty (54 FR 38044, September 14, 1989).

For the Oil and Natural Gas Production source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 40-in-1 million due to actual emissions and as high as 400-in-1 million due to MACT-allowable emissions (100-in-1 million, based on the lower end of the benzene URE range). While the 40-in-1 million risk due to actual emissions is considerably less than 100-in-1 million, which is the presumptive limit of acceptability, the 400-in-1 million risk due to allowable emissions is considerably higher and is considered unacceptable. We do note, however, that the risk analysis shows low cancer incidence (1 case in every 50 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic noncancer health impacts are unlikely.

We also conclude that acute noncancer health impacts are unlikely. As discussed above, screening estimates of acute exposures and risks were evaluated for each of the HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids) assuming that a person is located at this spot at a time when both the peak emission rate and worst-case dispersion conditions occur. Under these worst-case conditions, we estimate benzene acute HQ values (based on the REL) could be as high as 9. Although the REL (which indicates the level below which adverse effects are not anticipated) is exceeded in this case, we believe the potential for acute effects is low for several reasons. First, the acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions.

Second, the benzene REL is based on a 6-hour exposure duration because a 1-hour exposure duration value was unavailable. An REL based on a 6-hour exposure duration is generally lower than an REL based on a 1-hour exposure duration and, consequently, easier to exceed. Also, although there are exceedances of the REL, the highest estimated 1-hour exposure is less than 10 percent of the AEGL–1 value, which is a level at which effects could be experienced. Finally, the generally sparse populations near these facilities make it less likely that a person would be near the plant to be exposed. For example, in the two cases where the acute HQ value is as high as 9, there are only 30 people associated with the census blocks within 2 miles of the two facilities.

While our additional analysis of facility-wide risks showed that there is one facility with maximum facility-wide cancer risk of 100-in-1 million or greater and 10 facilities with a maximum chronic noncancer TOSHI greater than 1, it also showed that oil and natural gas production operations did not drive these risks.

In determining whether risk is acceptable, we considered the available health information, as described above. In this case, although a number of factors we considered indicate relatively low risk concern, we are proposing to determine that the risks are unacceptable, in large part, because the MIR is 400-in-1 million due to MACT-allowable emissions, which greatly exceeds the ''presumptive limit on maximum individual lifetime risk of approximately 1-in-10 thousand [100-in-1 million] recognized in the Benzene NESHAP (54 FR 38045).'' The MIR, based on MACT-allowable emissions, is driven by the allowable emissions of 0.9 Mg/yr benzene under the MACT as a compliance option. We are, therefore, proposing to eliminate the alternative compliance option of 0.9 Mg/yr benzene from the existing glycol dehydrator MACT requirements. With this change, the source category MIR, based on MACT-allowable emissions, would be reduced to 40-in-1 million, which we find acceptable in light of all the other factors considered. Thus, we are proposing that the risks from the Oil and Natural Gas Production source category are acceptable, with the removal of the alternative compliance option of 0.9 Mg/yr benzene limit from the current glycol dehydrator MACT requirements.

Pursuant to CAA section 112(f)(4), we are proposing that this change (*i.e.,* removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not this is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A).

We recognize that our proposal to remove the 0.9 Mg/yr compliance alternative for the 95-percent control glycol dehydrator MACT standard could have negative impacts on some sources that have come to rely on the flexibility this alternative provides. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work and how it would reduce risk.

ii. Ample Margin of Safety

We next considered whether this revised standard (existing MACT plus removal of 0.9 Mg/yr benzene compliance option) provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information along with all of the health risks and other health information considered in the risk acceptability determination.

For glycol dehydrators, we considered the addition of a second control device in the same manner that was discussed in the floor evaluation in section VII.B.1 above. The cost effectiveness associated with that option would be $167,200/Mg, which we believe is too high to require additional controls on glycol dehydrators.

Similarly, we considered the addition of a second control device to the required MACT floor control device (cost effectiveness of $18,300/Mg). Similar to our discussion of beyond-the-MACT-floor controls for glycol dehydrators in section VII.B.1 of this preamble, the incremental cost to add a second control device for storage vessels would be approximately 20 times higher than the MACT floor cost effectiveness, or $366,000/Mg. We do not believe this cost effectiveness is reasonable.

For leak detection, we considered implementation of LDAR programs that are more stringent than the current standards. An assessment performed for various LDAR options under the NSPS in section VI.B.4.b of this preamble yielded the lowest cost effectiveness of $5,170/Mg ($4,700/ton) for control of VOC for the options evaluated. A LDAR program to control HAP would involve similar costs for equipment, labor, etc., to those considered in the NSPS assessment, but since there is approximately 20 times less HAP than VOC present in material handled in regulated equipment, the cost effectiveness to control HAP would be approximately 20 times greater (*i.e.,* $100,000/Mg) for HAP, which we believe is not reasonable.

In accordance with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors in making our ample margin of safety determination. Considering the health risk information and the high cost effectiveness of the options identified, we propose that the existing MACT standards, with the removal of the 1 tpy benzene limit compliance option from the glycol dehydrator standards, provide an ample margin of safety to protect public health.

While we are proposing that the oil and natural gas production MACT standards (with the removal of the alternative compliance option of 1 tpy benzene limit) provide an ample margin of safety to protect public health, we are concerned about the estimated facility-wide risks identified through these screening analyses. As described previously, the highest estimated facility-wide cancer risks are mostly due to emissions from oil fired boilers and RICE. Both of these sources are regulated under other source categories and we anticipate that emission reductions from those sources will occur as standards for those source categories are implemented.

3. What are the results and proposed decisions from the risk review for the Natural Gas Transmission and Storage source category?

a. Results of the Risk Assessments and Analyses

We conducted an inhalation risk assessment for the Natural Gas Transmission and Storage source category. We also conducted an assessment of facility-wide risk and performed a demographic analysis of population risks. Details of the risk assessments and analyses can be found in the residual risk documentation, which is available in the docket for this action.

i. Inhalation Risk Assessment Results

Table 5 provides an overall summary of the results of the inhalation risk assessment. For informational purposes and to examine the potential for any EJ issues that might be associated with each source category, we performed a demographic analysis of population risks.

TABLE 5—NATURAL GAS TRANSMISSION AND STORAGE INHALATION RISK ASSESSMENT RESULTS

Number of Facilities[1]	Maximum individual cancer risk (in 1 million)[2]		Estimated population at risk ≥ 1-in-1 million	Estimated annual cancer incidence (cases per year)	Maximum chronic noncancer TOSHI[4]		Maximum off-site acute noncancer HQ[5]
	Actual emissions level	Allowable emissions level			Actual emissions level	Allowable emissions level	
321	[3] 30–90	[3] 30–90	[3] 2,500	[3] 0.0003–0.001	0.4	0.8	HQ_{REL} = 5 (benzene) HQ_{AEGL-1} = 0.2 (chlorobenzene)

[1] Number of facilities evaluated in the risk analysis.

[2] Estimated maximum individual excess lifetime cancer risk.

[3] The EPA IRIS assessment for benzene provides a range of equally-plausible URE (2.2E–06 to 7.8E–06 per ug/m^3), giving rise to ranges for the estimates of cancer MIR and cancer incidence. Estimated population values are not scalable with benzene URE range, but would be lower using the lower end of the URE range.

[4] Maximum TOSHI. The target organ with the highest TOSHI for the Natural Gas Transmission and Storage source category is the immune system.

[5] The maximum estimated acute exposure concentration was divided by available short-term dose-response values to develop an array of HQ values.

As shown in Table 5 above, the results of the inhalation risk assessment performed using actual emissions data indicate the maximum lifetime individual cancer risk could be as high as 90-in-1 million, (30-in-1 million based on the lower end of the benzene URE range), with benzene as the major contributor to the risk. The total estimated cancer incidence from the source category is 0.001 excess cancer cases per year (0.0003 excess cancer cases per year based on the lower end of the benzene URE range), or one case in every polycyclic organic matter 1,000 years. Approximately 2,500 people are estimated to have cancer risks at or above 1-in-1 million as a result of the emissions from 15 facilities (use of the lower end of the benzene URE range would further reduce this population estimate). The maximum chronic noncancer TOSHI value for the source category could be up to 0.4 from emissions of benzene, indicating no significant potential for chronic noncancer impacts.

As explained above in section VII.C.1.b, our analysis of potential differences between actual emission levels and emissions allowable under the natural gas transmission and storage MACT standard indicate that MACT-allowable emission levels may be up to 50 times greater than actual emission levels at some sources. However, because some sources are emitting at the level allowed under the current NESHAP, the risk results from the inhalation risk assessment indicate the maximum lifetime individual cancer risk would still be 90-in-1 million (30-in-1 million based on the lower end of the benzene URE range), based on both actual and allowable emission levels, and the maximum chronic noncancer TOSHI value could be as high as 0.8 at the MACT-allowable emissions level.

ii. Facility-Wide Risk Assessment Results

A facility-wide risk analysis was also conducted based on actual emissions levels. Table 6 below displays the results of the facility-wide risk assessment. For detailed facility-specific results, see Table 2 of Appendix 6 of the risk document in the docket for this rulemaking.

TABLE 6—NATURAL GAS TRANSMISSION AND STORAGE FACILITY-WIDE RISK ASSESSMENT RESULTS

Number of Facilities Analyzed	321
Cancer Risk:	
Estimated maximum facility-wide individual cancer risk (in 1 million)	[1] 200
Number of facilities with estimated facility-wide individual cancer risk of 100-in-1 million or more	3
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide individual cancer risks of 100-in-1 million or more	1
Number of facilities with facility-wide individual cancer risk of 1-in-1 million or more	74
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide individual cancer risk of 1-in-1 million or more	10
Chronic Noncancer Risk:	
Maximum facility-wide chronic noncancer TOSHI	80
Number of facilities with facility-wide maximum noncancer TOSHI greater than 1	30
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide maximum noncancer TOSHI of 1 or more	0

[1] We note that the MIR would be 100-in-1 million if the CIIT URE for formaldehyde were used instead of the IRIS URE.

The facility-wide MIR from all HAP emissions at any facility that contains sources subject to the natural gas transmission and storage MACT standards is estimated to be 200-in-1 million, based on actual emissions. Of the 321 facilities included in this analysis, three have facility-wide MIR of 100-in-1 million or greater. The facility-wide MIR is 200-in-1 million at two of these facilities, driven by formaldehyde from RICE.[37] Another facility has a facility-wide risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas transmission and storage. There are 74 facilities with facility-wide MIR of 1-in-1 million or greater. Of these facilities, 10 have natural gas transmission and storage operations that contribute greater than 50 percent to the facility-wide risks. As discussed above, we are proposing MACT standards for benzene emissions from small glycol dehydrators in this action. These standards would reduce the risk from benzene emissions at facilities with natural gas transmission and storage operations. The facility-wide cancer risks at the facilities with risks of 1-in-1 million or more are primarily driven by formaldehyde emissions from RICE, which will be assessed in a future RTR for that category.

The facility-wide maximum individual chronic noncancer TOSHI is estimated to be 80, based on actual emissions. Of the 321 facilities included in this analysis, 30 have facility-wide maximum chronic noncancer TOSHI values greater than 1. Of these facilities, none had natural gas transmission and storage operations that contributed greater than 50 percent to these facility-wide risks. The chronic noncancer risks at these facilities are primarily driven by acrolein emissions from RICE.

iii. Demographic Risk Analysis Results

The results of the demographic analyses performed to investigate the distribution of cancer risks at or above 1-in-1 million among the surrounding population are summarized in Table 7 below. These results, for various demographic groups, are based on actual emissions levels for the population living within 50 km of the facilities.

TABLE 7—NATURAL GAS TRANSMISSION AND STORAGE DEMOGRAPHIC RISK ANALYSIS RESULTS

	Nationwide	Population with cancer risk at or above 1-in-1 million due to . . .	
		Source category HAP emissions	Facility-wide HAP emissions
Total Population	285,000,000	2,500	99,000
Race by Percent			
White	75	92	58
All Other Races	25	8	42
Race by Percent			
White	75	92	58
African American	12	6	40
Native American	0.9	0.1	0.2
Other and Multiracial	12	1	2
Ethnicity by Percent			
Hispanic	14	1	2
Non-Hispanic	86	99	98
Income by Percent			
Below Poverty Level	13	17	20
Above poverty level	87	83	80
Education by Percent			
Over 25 and without High School Diploma	13	20	15
Over 25 and with a High School Diploma	87	80	85

The results of the Natural Gas Transmission and Storage source category demographic analysis indicate that there are approximately 2,500 people exposed to a cancer risk at or above 1-in-1 million due to emissions from the source category, including an estimated 8 percent that are classified as minority (listed as ‘‘All Other Races’’ in Table 7 above). Of the 2,500 people with estimated cancer risks at or above 1-in-1 million from the source category, 17 percent are in the ‘‘Below Poverty Level’’ demographic group, and 20 percent are in the ‘‘Over 25 and without High School Diploma’’ demographic group, results which are 4 and 7 percentage points higher, respectively, than the percentages for these demographic groups across the United States. The percentages for the other demographic groups are lower than their respective nationwide percentages. The table also shows that there are approximately 99,000 people exposed to an estimated cancer risk at or above 1-in-1 million due to facility-wide emissions, including an estimated 42 percent that are classified as minority (‘‘All Other Races’’ in Table 7 above). Of the 99,000 people with estimated cancer risk at or above 1-in-1 million from facility-wide emissions, 40 percent are in the ‘‘African American’’ demographic group, 20 percent are in the ‘‘Below Poverty Level’’ demographic group, and 15 percent are in the ‘‘Over 25 and without High School Diploma’’ demographic group, results which are 28, 7 and 2 percentage points higher, respectively, than the percentages for these demographic groups across the United States. The percentages for the other demographic groups are equal to

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[37] We note that there is an ongoing IRIS reassessment for formaldehyde, and that future RTR risk assessments will use the cancer potency for formaldehyde that results from that reassessment. As a result, the current results may not match those of future assessments.

or lower than their respective nationwide percentages.

b. What are the proposed risk decisions for the Natural Gas Transmission and Storage source category?

i. Risk Acceptability

In the risk analysis we performed for this source category, pursuant to CAA section 112(f)(2), we considered the available health information—the MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer HI; the maximum acute noncancer hazard; the extent of noncancer risks; the potential for adverse environmental effects; distribution of risks in the exposed population; and risk estimation uncertainty (54 FR 38044, September 14, 1989).

For the Natural Gas Transmission and Storage source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 90-in-1 million due to actual and allowable emissions (30-in-1 million, based on the lower end of the benzene URE range). These risks are near 100-in-1 million, which is the presumptive limit of acceptability. On the other hand, the risk analysis shows low cancer incidence (1 case in every 1,000 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic and acute noncancer health impacts are unlikely. We conclude that acute noncancer health impacts are unlikely for reasons similar to those described in section VII.C.2.b.i of this preamble.

Our additional analysis of facility-wide risks showed that, among three facilities with maximum facility-wide cancer risk of 100-in-1 million or greater, one facility has a facility-wide cancer risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas and transmission and storage. There are 30 facilities with a maximum chronic noncancer TOSHI greater than 1, but natural gas transmission and storage operations did not drive this risk.

In determining whether risk is acceptable, we considered the available health information, as described above. In this case, because the MIR is approaching, but still less than 100-in-1 million risk, and because a number of other factors indicate relatively low risk concern (*e.g.,* low cancer incidence, low potential for adverse environmental effects or human health multi-pathway effects, chronic and acute noncancer health impacts unlikely), we are proposing to determine that the risks are acceptable.

ii. Ample Margin of Safety

We next considered whether the existing MACT standard provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information, along with all of the health risks and other health information considered in the risk acceptability determination. The estimated MIR of 90-in-1 million discussed above is driven by the 0.9 Mg/year benzene limit compliance alternative for the glycol dehydrator MACT standard in the current NESHAP. Removal of this compliance alternative would lower the MIR for the source category to 20-in-1 million. We, therefore, considered removing this compliance alternative as an option for reducing risk and assessed the cost of such alternative. Without the compliance alternative, affected glycol dehydrators (*i.e.,* those units with annual average benzene emissions of 0.9 Mg/yr or greater and an annual average natural gas throughput of 283,000 scmd or greater) must demonstrate compliance with the 95-percent control requirement, which we believe can be shown with their existing control devices in most cases, although, in some instances, installation of a different or an additional control may be necessary.

In section VII.B.1 above, we discuss the costs for requiring controls on currently unregulated ‘‘small glycol dehydrators,’’ which are similar, in operation and type of emission controls, to the dehydrators subject to the current MACT (‘‘large dehydrators’’). The HAP cost effectiveness determined for small dehydrators at the floor level of control was $1,650/Mg. Although control methodologies are similar for large and small dehydrators, we expect that the costs for controls on large units could be as much as twice as high as for small units because of the large gas flow being processed. However, we also expect that the amount of HAP emission reduction for the large dehydrators, in general, to be as much as, or more than, the amount achieved by small dehydrators. In light of the above, we do not expect the cost effectiveness of the control device needed to meet the 95-percent control requirement for large dehydrators to exceed $3,300/Mg (*i.e.,* twice the cost effectiveness for small dehydrators), which we consider to be reasonable.

In accordance with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors in making our ample margin of safety determination. Considering the health risk information and the reasonable cost effectiveness of the option identified, we propose that the existing MACT standards, with the removal of the 0.9 Mg benzene limit compliance option from the glycol dehydrator standards, provide an ample margin of safety to protect public health.

Pursuant to CAA section 112(f)(4), we are proposing that this change (*i.e.,* removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not there is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A).

We recognize that our proposal to remove the one-ton compliance alternative for the 95-percent control glycol dehydrator MACT standard could have negative impacts on some sources that have come to rely on the flexibility this alternative provides. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work, and how it would reduce risk.

As described above, we are proposing that the natural gas transmission and storage MACT standards (with the removal of the 0.9 Mg/yr benzene limit compliance option) provide an ample margin of safety to protect public health. We recognize that one facility has a facility-wide cancer risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas transmission and storage. This risk is driven by benzene emissions from glycol dehydrators and is being addressed by our proposed revision to the Natural Gas Transmission and Storage NESHAP (removal of the 0.9 Mg/yr benzene limit compliance option). As previously mentioned, two facilities have facility-wide MIR of 200-in-1 million, driven by formaldehyde from RICE. Emissions from RICE are regulated under another source category and will be assessed under a future RTR for that category.

D. How did we perform the technology review and what are the results and proposed decisions?

1. What was the methodology for the technology review?

Our technology review is focused on the identification and evaluation of ''developments in practices, processes, and control technologies'' since the promulgation of the MACT standards for the two oil and gas source categories. If a review of available information identifies such developments, then we conduct an analysis of the technical feasibility of requiring the implementation of these developments, along with the impacts (costs, emission reductions, risk reductions, etc.). We then make a decision on whether it is necessary to amend the regulation to require these developments.

Based on specific knowledge of each source category, we began by identifying known developments in practices, processes and control technologies. For the purpose of this exercise, we considered any of the following to be a ''development'':

- Any add-on control technology or other equipment that was not identified and considered during MACT development;
- Any improvements in add-on control technology or other equipment (that was identified and considered during MACT development) that could result in significant additional emission reduction;
- Any work practice or operational procedure that was not identified and considered during MACT development; and
- Any process change or pollution prevention alternative that could be broadly applied that was not identified and considered during MACT development.

In addition to looking back at practices, processes or control technologies reviewed at the time we developed the MACT standards, we reviewed a variety of sources of data to aid in our evaluation of whether there were additional practices, processes or controls to consider. One of these sources of data was subsequent air toxics rules. Since the promulgation of the MACT standards for the source categories addressed in this proposal, the EPA has developed air toxics regulations for a number of additional source categories. We reviewed the regulatory requirements and/or technical analyses associated with these subsequent regulatory actions to identify any practices, processes and control technologies considered in these efforts that could possibly be applied to emission sources in the source categories under this current RTR review.

We also consulted the EPA's RBLC. The terms ''RACT,'' ''BACT,'' and ''LAER'' are acronyms for different program requirements under the CAA provisions addressing the NAAQS. Control technologies classified as RACT, BACT or LAER apply to stationary sources depending on whether the source exists or is new and on the size, age and location of the facility. The BACT and LAER (and sometimes RACT) are determined on a case-by-case basis, usually by state or local permitting agencies. The EPA established the RBLC to provide a central database of air pollution technology information (including technologies required in source-specific permits) to promote the sharing of information among permitting agencies and to aid in identifying future possible control technology options that might apply broadly to numerous sources within a category or apply only on a source-by-source basis. The RBLC contains over 5,000 air pollution control permit determinations that can help identify appropriate technologies to mitigate many air pollutant emission streams. We searched this database to determine whether any practices, processes or control technologies are included for the types of processes used for emission sources (*e.g.,* spray booths) in the source categories under consideration in this proposal.

We also consulted information from the Natural Gas STAR program. The Natural Gas STAR program is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt cost effective technologies and practices that improve operational efficiency and reduce pollutant emissions. The program provides the oil and gas industry with information on new techniques and developments to reduce pollutant emissions from the various processes.

2. What are the results and proposed decisions from the technology review?

There are three types of emission sources covered by the two oil and gas NESHAP. These sources and the control technologies (including add-on control devices and process modifications) considered during the development of the MACT standards are: Glycol dehydrators (combustion devices, recovery devices, process modifications), storage vessels with the PFE (combustion devices, recovery devices) and equipment leaks (LDAR programs, specific equipment modifications). Dehydrators are addressed by both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, while equipment leaks and storage vessels with the PFE are only covered by subpart HH.

Since the promulgation of 40 CFR part 63, subpart HH, which established MACT standards to address HAP emissions from equipment leaks at gas processing plants, the EPA has developed LDAR programs that are more stringent than what is required in subpart HH. The most prevalent differences between these more stringent programs and subpart HH relate to the frequency of monitoring and the concentration which constitutes a ''leak.'' We do consider these programs to represent a development in practices and evaluated whether to revise the MACT standards for equipment leaks at natural gas processing plants under subpart HH in light of this development.

An analysis was performed above in section VI.B.1 to assess the VOC reduction, costs and other impacts associated with these more stringent LDAR program options at natural gas processing plants. One option considered was to require compliance with 40 CFR part 60, subpart VVa instead of 40 CFR part 60, subpart VV (the current NSPS requirement for equipment leaks of VOC at natural gas processing plants), which changes the leak definition (based on methane) from 10,000 ppm to 500 ppm and requires monitoring of connectors. Because the current leak definition under NESHAP 40 CFR part 63, subpart HH is the same as that in NSPS subpart VV, and the ratio of VOC to HAP is approximately 20 to 1, we expect that the HAP reduction would be 1/20th of the VOC reduction under subpart VVa. The estimated incremental cost for that option was determined to be $3,340 per ton of VOC. Based on the 20-to-1 ratio, we estimate the incremental cost to control HAP at the subpart VVa level would be approximately $66,800 per ton of HAP ($73,480/Mg). Other options considered in section VI.B.1 of this preamble (and the incremental cost of each option for reducing HAP) are as follows: The use of an optical gas imaging camera monthly with an annual EPA Method 21 check ($129,000 per ton of HAP/$143,600 per Mg, if purchasing the camera; $93,000 per ton of HAP/$103,300 per Mg, if renting the camera); monthly optical gas imagining alone; and annual optical gas imaging.[38] In

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[38] As stated above in section VI.B.1, emissions for the two options using the optical gas imaging camera alone cannot be quantified and, therefore, no cost effectiveness values were determined.

light of the above, we do not believe that the additional costs of these programs are justified.

In addition to the plant-wide evaluations, a component analysis was also evaluated at gas processing plants for the 40 CFR part 60, subpart VVa-level of control (option 1 considered in section VI.B.1).[39] That assessment shows that the subpart VVa-level of control for connectors has an incremental cost effectiveness of $4,360 per ton for VOC for connectors and $144 per ton for VOC for valves. This means the incremental cost to control HAP would be approximately $87,200 per ton ($96,900/Mg) for connectors and $2,880 per ton ($3,200/Mg) for valves. We do not believe the additional cost for the more stringent requirement for connectors is justified, but the additional cost for valves is justified. Therefore, we are proposing to revise the equipment leak requirements in 40 CFR part 63, subpart HH to lower the leak definition for valves to an instrument reading of at least 500 ppm as a result of our technology review.

Some of the practices, processes or control technologies listed by the Natural Gas STAR program applicable to the emission sources in these categories were not identified and evaluated during the original MACT development. While the Natural Gas STAR program does contain information regarding new innovative techniques that are available to reduce HAP emissions, they are not considered to have emission reductions higher than what is set by the original MACT. One control technology identified in the Natural Gas STAR program that would result in no HAP emissions from glycol dehydration units would be the replacement of a glycol dehydration unit with a desiccant dehydrator. This technology cannot be used for natural gas operations with gas streams having high temperature, high volume, and low pressure. Due to the limitations posed by these conditions, we do not consider desiccant dehydrators as MACT.

For storage vessels, the applicable technologies identified by the Gas STAR program, which are evaluated above for proposal under NSPS in section VI.B.4, are similar to the cover and control technologies currently required for storage vessels under the existing MACT. Therefore, these technologies would not result in any further emissions reductions than what is achieved by the original MACT.

Our review of the RBLC did not identify any practices, processes and control technologies applicable to the emission sources in these categories that were not identified and evaluated during the original MACT development. In light of the above, we are not proposing any revisions to the existing MACT standards for storage vessels pursuant to section 112(d)(6) of the CAA.

E. What other actions are we proposing?

1. Combustion Control Device Testing

As explained below in section VII.E.2, under our proposal, performance testing would be required initially and every 5 years for non-condenser control devices. However, for certain enclosed combustion control devices, we are proposing to allow, as an alternative to on-site testing, a performance test conducted by a control device manufacturer in accordance with the procedures provided in this proposal. We propose to allow a unit whose model meets the proposed performance criteria to claim a BTEX or HAP destruction efficiency of 98 percent at the facility. This value is lower than the 99.9-percent destruction efficiency required in the manufacturers' test due to variations between the test fuel specified and the gas streams combusted at the actual facility. A source subject to the small dehydrator BTEX limit would use the 98-percent destruction efficiency to calculate their dehydrator's BTEX emissions for the purpose of demonstrating compliance. For the 95-percent control MACT standard, a control device matching the tested model would be considered to meet that requirement. Once a device has been demonstrated to meet the proposed performance criteria (and, therefore, is assigned a 98-percent destruction efficiency), installation of a unit matching the tested model at a facility would require no further performance testing (*i.e.,* periodic tests would not be required every 5 years).

We are proposing this alternative to minimize issues associated with performance testing of certain combustion control devices. We believe that testing units that are not configured with a distinct combustion chamber present several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers' recommendations. One issue is that an extension above certain existing combustion control device enclosures will be necessary to get adequate clearance above the flame zone. Such extensions can more easily be configured by the manufacturer of the control device rather than having to modify an extension in the field to fit devices at every site. Issues related to transporting, installing and supporting the extension in the field are also eliminated through manufacturer testing. Another concern is that the pitot tube used to measure flow can be altered by radiant heat from the flame such that gas flow rates are not accurate. This issue is best overcome by having the manufacturer select and use the pitot tube best suited to their specific unit. For these reasons, we believe the manufacturers' test is appropriate for these control devices with ongoing performance ensured by periodic inspection and maintenance.

This proposed alternative does not apply to flares, as defined in 40 CFR 63.761 and 40 CFR 63.1271, which must demonstrate compliance by meeting the design and operation requirements in 40 CFR 63.11(b), 40 CFR 63.772(e)(2) and 40 CFR 63.1282(d)(2). It also would not apply to thermal oxidizers having a combustion chamber/firebox where combustion temperature and residence time can be measured during an on-site performance test and are valid indicators of performance. These thermal oxidizers do not present the issues described above relative to on-site performance testing and, therefore, do not need an alternative testing option. The proposed alternative would, therefore, apply to enclosed combustion control devices except for these thermal oxidizers.

In conjunction with the proposed manufacturer testing alternative, we are proposing to add a definition for flare to clarify that flares, as referenced in the NESHAP (and to which the proposed testing alternative does not apply), refers to a thermal oxidation system with an open flame (*i.e.,* without enclosure). Accordingly, any thermal oxidation system that does not meet the proposed flare definition would be considered an enclosed combustion control device.

We estimate that there are many existing facilities currently using enclosed combustion control devices that would be required to either conduct an on-site performance test or install and operate a control device tested by the manufacturer under our proposal. Given the estimated number of these combustion control devices in use, the time required for manufacturers to test and manufacture such units, we are proposing that existing sources have up to 3 years from the date of the final rules' publication date to comply with

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[39] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

the initial performance testing requirements.

2. Monitoring, Recordkeeping and Reporting

We are proposing to make changes to the monitoring requirements described below to address issues we have identified through a monitoring sufficiency review performed during the RTR process. First, we are including calibration procedures associated with parametric monitoring requirements in the existing NESHAP. The NESHAP require parametric monitoring of control device parameters (*e.g.,* temperatures or flowrate monitoring), but did not include information on calibration or included inadequate information on calibration of monitoring devices. Therefore, we are specifying the calibration requirements for temperature and flow monitors that the NESHAP currently lacks.

In addition, under the current NESHAP, a design analysis can be used in lieu of performance testing to demonstrate compliance and establish operating parameter limits. We are proposing to allow the use of the design evaluation alternative only when the control device being used is a condenser. The design evaluation option is appropriate for condensers because their emissions can be accurately predicted using readily available physical property information (*e.g.,* vapor pressure data and condensation calculations). In those cases, one would not need to conduct emissions testing to determine actual emissions to demonstrate compliance with the MACT standard. For example, a requirement that ''the temperature at the outlet of the condenser shall be maintained at 50° Fahrenheit below the condensation temperature calculated for the compound of interest using the reference equation'' (*e.g.,* National Institute of Standards and Technology Chemistry WebBook at *http://webbook.nist.gov/chemistry/*) is adequate to assure proper operation of the condenser and, therefore, compliance with the required emission standard.

For other types of control technologies, such as carbon adsorption systems and enclosed combustion devices,[40] the ability to predict emissions depends on data developed by the vendor and such data may not reliably result in an accurate prediction of emissions from a specific facility. There are variables (*e.g.,* air to fuel ratios and waste constituents for combustion; varying organic concentrations, constituents and capacity issues, including break-through for carbon adsorption) that make theoretical predictions less reliable. The effects of these site-specific variables on emissions are not easily predictable and establishing monitoring conditions (*e.g.,* combustion temperature, vacuum regeneration) based on vendor data will likely not account for those variables. Therefore, we propose to eliminate the design evaluation alternative for non-condenser controls.

For non-condenser controls (and condensers not using the design analysis option), in addition to the initial compliance testing, we are proposing that performance tests be conducted at least once every 5 years and whenever sources desire to establish new operating limits. Under the current NESHAP, a performance test is only conducted in two instances: (1) As an alternative to a design analysis for their compliance demonstration and identification of operating parameter ranges and (2) as a requirement to resolve a disagreement between the EPA and the owner or operator regarding the design analysis. The current NESHAP do not require additional performance testing beyond these two cases (*i.e.,* there is no periodic testing requirement). As mentioned above, we are proposing to remove the design evaluation option for non-condenser controls. For non-condenser controls (and condensers not using the design analysis option), the proposed periodic testing would ensure compliance with the emission standards by verifying that the control device is meeting the necessary HAP destruction efficiency determined in the initial performance test. As discussed above in section VII.E.1, we are proposing that combustion control devices tested under the manufacturers' procedure are not required to conduct periodic testing. In addition, we are also proposing that combustion control devices that can demonstrate a uniform combustion zone temperature meeting the required control efficiency during the initial performance test are exempt from periodic testing. The requirement for continuous monitoring of combustion zone temperature is an accurate indicator of control device performance and eliminates the need for future testing.

The current NESHAP (40 CFR 63.771(d) and 40 CFR 63.1281(d)) require operating an enclosed combustion device at a minimum residence time of 0.5 seconds at a minimum temperature of 760 degrees Celsius. We are proposing to remove the residence time requirement. The residence time requirement is not needed because the compliance demonstration made during the performance test is sufficient to ensure that the combustion device has adequate residence time to ensure the needed destruction efficiency. Therefore, we are proposing to remove the residence time requirement.

We are also clarifying at 40 CFR 63.773(d)(3)(i) and 40 CFR 63.1283(d)(3)(i) for thermal vapor incinerators, boilers and process heaters, that the temperature sensor shall be installed at a location representative of the combustion zone temperature. Currently, the regulation requires that the temperature sensor be installed at a location ''downstream of the combustion zone'' because we had thought that the temperature downstream would be representative of combustion zone temperature. We have now learned that may or may not be the case. We are, therefore, proposing to amend this provision to more accurately reflect the intended requirement.

Next, consistent with revisions for SSM, we've revised 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i), except when maintenance or repair on a unit cannot be completed without a shutdown of the control device.

Also, we've updated the criteria for prior performance test results that can be used to demonstrate compliance in lieu of conducting a performance test. These updates ensure that data for determining compliance are accurate, up-to-date, and truly representative of actual operating conditions.

In addition, we are proposing to revise the temperature monitoring device minimum accuracy criteria in 40 CFR 63.773(d)(3)(i) to better reflect the level of performance that is required of the temperature monitoring devices. We believe that temperature monitoring devices currently used to meet the requirements of the NESHAP can meet the proposed revised criteria without modification.

Also, we are proposing to revise the calibration gas concentration for the no detectable emissions procedure applicable to closed vent systems in 40 CFR 63.772(c)(4)(ii) from 10,000 ppmv to 500 ppmv methane to be consistent with the leak threshold of 500 ppmv in 40 CFR part 63, subpart HH. The current calibration level is inconsistent with achieving accurate readings at the level necessary to demonstrate there are no detectable emissions.

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[40] The design analysis alternative in the existing MACT does not apply to flares. As previously mentioned, the existing MACT provides separate design and operation requirements for flares.

Also, we are proposing recordkeeping and reporting requirements for carbon adsorption systems. The current NESHAP require the replacement of all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon system, but provide no recordkeeping or reporting requirement to document and assure compliance with this standard. We believe that maintaining some sort of log book is a reasonable alternative combined with a requirement to report instances when specified practices are not followed. Therefore, the proposed rule adds reporting and recordkeeping requirements for establishing a schedule and maintaining logs of carbon replacement.

Finally, as noted above in section VII.B.1, we are proposing a BTEX emissions limit for small glycol dehydration unit process vents. For the compliance demonstration, we propose that parametric monitoring of the control device be performed. We believe that parametric monitoring is adequate for glycol dehydrators in these two source categories because temperature monitoring, whether it be to verify proper condenser or combustion device operation, is a reliable indicator of performance for reducing organic HAP emissions. We also considered the use of a continuous emissions monitoring system (CEMS) to monitor compliance. However, for glycol dehydrators in the oil and natural gas sector, the necessary electricity, weather-protective enclosures and daily staffing are not usually available. We, therefore, question the technical feasibility of operating a CEMS correctly in this sector. We request comment on the practicality of including provisions in the final rule for a CEMS to monitor BTEX emissions for small glycol dehydration units.

3. Startup, Shutdown, Malfunction

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied, 130 S. Ct. 1735 (U.S. 2010).* Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that is part of a regulation, commonly referred to as the *General Provisions Rule,* that the EPA promulgated under section 112 of the CAA. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

We are proposing the elimination of the SSM exemption in the two oil and gas NESHAP. Consistent with *Sierra Club* v. *EPA,* the EPA is proposing to apply the standards in these NESHAP at all times. In addition, we are proposing to revise 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i) to remove the provision allowing shutdown of the control device during maintenance or repair. We are also proposing several revisions to the General Provisions applicability table for the MACT standard. For example, we are proposing to eliminate the incorporation of the General Provisions' requirement that the source develop a SSM plan. We are also proposing to eliminate or revise certain recordkeeping and reporting requirements related to the SSM exemption. The EPA has attempted to ensure that we have not included in the proposed regulatory language any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether there are any such provisions that we have inadvertently incorporated or overlooked.

In proposing the MACT standards in these rules, the EPA has taken into account startup and shutdown periods. We believe that operations and emissions do not differ from normal operations during these periods such that it warrants a separate standard. Therefore, we have not proposed different standards for these periods.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 63.2). The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now* v. *EPA,* 370 F.3d 1232, 1242 (D.C. Cir. 2004), the Court upheld as reasonable, standards that had factored in variability of emissions under all operating conditions. However, nothing in CAA section 112(d) or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. See *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978), (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by ''uncontrollable acts of third parties,'' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.'').

Further, it is reasonable to interpret CAA section 112(d) as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of ''best performing'' sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of ''best performing'' to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for oil and natural gas production facility and natural gas transmission and storage operations. As noted above, by definition, malfunctions are sudden and unexpected events, and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in each source category. Moreover, malfunctions can also vary in frequency, degree and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause or contribute to an exceedance of the relevant emission standard. (See, *e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (September 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (February 15, 1983)). The EPA is, therefore, proposing to add to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions in both of the MACT standards addressed in this proposal. See 40 CFR 63.761 for sources subject to the oil and natural gas production MACT standards, or 40 CFR 63.1271 for sources subject to the natural gas transmission and storage MACT standards (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; a source subject to the oil and natural gas production facilities or natural gas transmission MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.762 and a source subject to the natural gas transmission and storage facilities MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.1272. (See 40 CFR 22.24.) The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.762 for sources subject to the oil and natural gas production facilities MACT standards or 40 CFR 63.1272 for sources subject to the natural gas transmission and storage facilities MACT standards and to prevent future malfunctions. For example, the source must prove by a preponderance of evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.77).

4. Applicability and Compliance

a. Calculating Potential To Emit (PTE)

We are proposing to amend section 40 CFR 63.760(a)(1)(iii) to clarify that sources must use a glycol circulation rate consistent with the definition of PTE in 40 CFR 63.2 in calculating emissions for purposes of determining PTE. Affected parties have misinterpreted the current language concerning measured values or annual average to apply to a broader range of parameters than was intended. Those qualifiers were meant to apply to gas characteristics that are measured, such as inlet gas composition, pressure and temperature rather than process equipment settings. That means that the circulation rate used in PTE determinations shall be the maximum under its physical and operational design.

In addition to the proposed changes described above, we are seeking comment on several PTE related issues. According to the data available to the Administrator, when 40 CFR part 63, subpart HH was promulgated, the level of HAP emissions was predominantly driven by natural gas throughput (*i.e.,* HAP emissions went up or down in concert with natural gas throughput). Since promulgation, we have learned that there is not always a direct correlation between HAP emissions and natural gas throughput. We have received information suggesting that, in some cases, HAP emissions can increase despite decreasing natural gas throughput due to changes in gas composition. We are asking for comment regarding the likelihood of this occurrence and data demonstrating the circumstances where it occurs. In light of the potential issue, we are asking for comment regarding the addition of provisions in the NESHAP to require area sources to recalculate their PTE to confirm that they are indeed area sources and whether that calculation should be performed on an annual or biannual basis to verify that changes in gas composition have not increased their emissions.

b. Definition of Facility and Applicability Criteria

Subpart HH of 40 CFR part 63 (section 63.760(a)(2)) currently defines facilities as those where hydrocarbon liquids are processed, upgraded or stored prior to the point of custody transfer or where natural gas is processed, upgraded or stored prior to entering the Natural Gas Transmission and Storage source category. We are proposing to remove the references to ''point of custody transfer'' and ''transmission and storage source categories'' from the definition because the operations performed at a site sufficiently define a facility and the scope of the subpart is specified already under 40 CFR 63.760. In addition, we are removing the custody transfer reference from the applicability criteria in 40 CFR 63.760(a)(2). Since hydrocarbon liquids can pass through several custody transfer points between the well and the final destination, the custody transfer criteria is not clear enough. We are, therefore, proposing to replace the reference to ''point of custody transfer'' with a more specific description of the point up to which the subpart applies (*i.e.,* the point where hydrocarbon liquids enter either the organic liquids distribution or petroleum refineries source categories) and exclude custody transfer from that criteria. We believe this change eliminates ambiguity and is consistent with the oil and natural gas production-specific provisions in the organic liquids distribution MACT.

5. Other Proposed Changes To Clarify These Rules

The following lists additional changes to the NESHAP we are proposing. This list includes proposed rule changes that address editorial corrections and plain language revisions:

- Revise 40 CFR 63.769(b) to clarify that the equipment leak provisions in 40 CFR part 63, subpart HH do not apply to a source if that source is required to control equipment leaks under either 40 CFR part 63, subpart H or 40 CFR part 60, subpart KKK. The current 40 CFR 63.769(b), which states that subpart HH does not apply if a source meets the requirements in either of the subparts mentioned above, does not clearly express our intent that such source must be implementing the LDAR provisions in the other 40 CFR part 60 or 40 CFR part 63 subparts to qualify for the exemption.

- Revise 40 CFR 63.760(a)(1) to clarify that an existing area source that increases its emissions to major source levels has up to the first substantive compliance date to either reduce its emissions below major source levels by obtaining a practically enforceable permit or comply with the applicable major source provisions of 40 CFR part 63, subpart HH. We have revised the second to last sentence in 40 CFR 63.760(a)(1) by removing the parenthetical statement because it simply reiterates the last sentence of this section and is, therefore, unnecessary.
- Revise 40 CFR 63.771(d)(1)(ii) and 40 CFR 63.1281(d)(1)(ii) to clarify that the vapor recovery device and ''other control device'' described in those provisions refer to non-destructive control devices only.
- Revise the last sentence of 40 CFR 63.764(i) and 40 CFR 63.1274(g) to clarify the requirements following an unsuccessful attempt to repair a leak.
- Updated the e-mail and physical address for area source reporting in 40 CFR 63.775(c)(1).

VIII. What are the cost, environmental, energy and economic impacts of the proposed 40 CFR part 60, subpart OOOO and amendments to subparts HH and HHH of 40 CFR part 63?

We are presenting a combined discussion of the estimates of the impacts for the proposed 40 CFR part 60, subpart OOOO and proposed amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH. The cost, environmental and economic impacts presented in this section are expressed as incremental differences between the impacts of an oil and natural gas facility complying with the amendments to subparts HH and HHH and new standards under 40 CFR 60, subpart OOOO and the baseline, *i.e.,* the standards before these amendments. The impacts are presented for the year 2015, which will be the year that all existing oil and natural gas facilities will have to be in compliance, and also the year that will represent approximately 5 years of construction of new oil and natural gas facilities subject to the NSPS emissions limits. The analyses and the documents referenced below can be found in Docket ID Numbers EPA–HQ–OAR–2007–0877 and EPA–HQ–OAR–2002–0051.

A. What are the affected sources?

We expect that by 2015, the year when all existing sources will be required to come into compliance in the United States, there will be 97 oil and natural gas production facilities and 15 natural gas transmission and storage facilities with one or more existing glycol dehydration units. We also estimate that there will be an additional 329 (there are 47 facilities that already have an affected glycol dehydration unit) existing oil and natural gas production facilities with existing storage vessels that we expect to be affected by these final amendments. These facilities operate approximately 134 glycol dehydration units (115 in production and 19 in transmission and storage) and 1,970 storage vessels. Approximately 10 oil and natural gas production and two transmission and storage facilities would have new glycol dehydration units and 38 production facilities would have new dehydration units. We expect new production facilities would operate approximately 12 production glycol dehydration units and 197 storage vessels and new transmission and storage would operate approximately two glycol dehydration units.

Based on data provided by the United States Energy Information Administration, we anticipate that by 2015 there will be approximately 21,800 gas wellhead facilities, 790 reciprocating compressors, 30 centrifugal compressors, 14,000 pneumatic devices and 300 storage vessels subject to the new NSPS for VOC. Some of these affected facilities will be built at existing facilities and some at new greenfield facilities. Based on data limitations, we assume impacts are equal regardless of location.

There are about 21 glycol dehydration units with high enough HAP emissions that we believe cannot meet the emissions limit without using more than one control technique. In developing the cost impacts, we assume that they would require multiple controls. The controls for which we have detailed cost data are condensers and VRU, so we developed costs for both controls to develop what we consider to be a reasonable cost estimate for these facilities. This does not imply that we believe these facilities will specifically use a combination of a condenser and vapor recovery limit, but we do believe the combination of these control results is a reasonable estimate of cost.

B. How are the impacts for this proposal evaluated?

For these proposed Oil and Natural Gas Production and Natural Gas Transmission and Storage NESHAP amendments and NSPS, the EPA used two models to evaluate the impacts of the regulation on the industry and the economy. Typically, in a regulatory analysis, the EPA determines the regulatory options suitable to meet statutory obligations under the CAA. Based on the stringency of those options, the EPA then determines the control technologies and monitoring requirements that sources might rationally select to comply with the regulation. This analysis is documented in an engineering analysis. The selected control technologies and monitoring requirements are then evaluated in a cost model to determine the total annualized control costs. The annualized control costs serve as inputs to an Economic Impact Analysis model that evaluates the impacts of those costs on the industry and society as a whole.

The Economic Impact Analysis used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the United States DOE and is used to produce the *Annual Energy Outlook,* a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. The impacts we estimated included changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas and changes in international trade of crude oil and natural gas. We evaluated whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. Additionally, we combined estimated emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2e GHG from energy-related sources.

C. What are the air quality impacts?

For the oil and natural gas sector NESHAP and NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions associated with the proposed amendments to 40 CFR part 63, subpart

HH and 40 CFR part 63, subpart HHH are based on the estimated population in 2008. Under the proposed limits for glycol dehydration units and storage vessels, we have estimated that the HAP emissions reductions will be 1,400 tpy for existing units subject to the proposed emissions limits.

For the NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions are based on the estimated population in 2015. Under the proposed NSPS, we have estimated that the emissions reductions will be 540,000 tpy VOC for affected facilities subject to the NSPS.

The control strategies likely adopted to meet the proposed NESHAP amendments and the proposed NSPS will result in concurrent control of HAP, methane and VOC emissions. We estimate that direct reductions in HAP, methane and VOC for the proposed rules combined total about 38,000 tpy, 3.4 million tpy and 540,000 tpy, respectively.

Under the final standards, new monitoring requirements are being added.

D. What are the water quality and solid waste impacts?

We estimated minimal water quality impacts for the proposed amendments and proposed NSPS. For the proposed amendments to the NESHAP, we anticipate that the water impacts associated with the installation of a condenser system for the glycol dehydration unit process vent would be minimal. This is because the condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal, usually by reinjection.

Similarly, the water impacts associated with installation of a vapor control system either on a glycol dehydration unit or a storage vessel would be minimal. This is because the water vapor collected along with the hydrocarbon vapors in the vapor collection and redirect system can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with the produced water for disposal for reinjection.

There would be no water impacts expected for facilities subject to the proposed NSPS. Further, we do not anticipate any adverse solid waste impacts from the implementation of the proposed NESHAP amendments and the proposed NSPS.

E. What are the secondary impacts?

Indirect or secondary air quality impacts include impacts that will result from the increased electricity usage associated with the operation of control devices, as well as water quality and solid waste impacts (which were just discussed) that might occur as a result of these proposed actions. We estimate the proposed amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH will increase emissions of criteria pollutants due to the potential use of flares for the control of storage vessels. We do not estimate an increased energy demand associated with the installation of condensers, VRU or flares. The increases in criteria pollutant emissions associated with the use of flares to control storage vessels subject to existing source standards are estimated to be 5,500 tpy of CO_2, 16 tpy of carbon monoxide (CO), 3 tpy of NO_X, less than 1 tpy of particulate matter (PM) and 6 tpy total hydrocarbons. For storage vessels subject to new source standards, increases in secondary air pollutants are estimated to be less than 900 tpy of CO_2, 3 tpy of CO, 1 tpy of NO_X, 1 tpy of PM and 1 tpy total hydrocarbons.

In addition, we estimate that the secondary impacts associated with the pneumatic controller requirements to comply with the proposed NSPS would be about 22 tpy of CO_2, 1 tpy of NO_X and 3 tpy PM. For gas wellhead affected facilities, we estimate that the use of flares would result in increases in criteria pollutant emissions of about 990,000 tons of CO_2, 2,800 tpy of CO, 500 tpy of NO_X, 5 tpy of PM and 1,000 tpy total hydrocarbons.

F. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the control options analyzed under the proposed NESHAP amendments and proposed NSPS.

The proposed NESHAP amendments and proposed NSPS encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate that can be used on-site as fuel or reprocessed within the production process for sale. We estimated that the proposed standards will result in a net cost savings due to the recovery of salable natural gas and condensate. Thus, the final standards have a positive impact associated with the recovery of non-renewable energy resources.

G. What are the cost impacts?

The estimated total capital cost to comply with the proposed amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $51.5 million. The total capital cost for the proposed amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $370 thousand. All costs are in 2008 dollars.

The total estimated net annual cost to industry to comply with the proposed amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $16 million. The total net annual cost for proposed amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $360,000. These estimated annual costs include: (1) The cost of capital, (2) operating and maintenance costs, (3) the cost of monitoring, inspection, recordkeeping and reporting (MIRR) and (4) any associated product recovery credits. All costs are in 2008 dollars.

The estimated total capital cost to comply with the proposed NSPS is approximately $740 million in 2008 dollars. The total estimated net annual cost to industry to comply with the proposed NSPS is approximately $740 million in 2008 dollars. This annual cost estimate includes: (1) The cost of capital, (2) operating and maintenance costs and (3) the cost of MIRR. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas and hydrocarbon condensates.

When revenues from additional product recovery are considered, the proposed NSPS is estimated to result in a net annual engineering cost savings overall. When including the additional natural gas recovery in the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The engineering analysis cost analysis assumes the value of recovered condensate is $70 per barrel. Based on the engineering analysis, about 180,000,000 Mcf (180 billion cubic feet) of natural gas and 730,000 barrels of condensate are estimated to be recovered by control requirements in 2015. Using the price assumptions, the estimated revenues from natural gas product recovery are approximately $780 million in 2008 dollars. This savings is estimated at $45 million in 2008 dollars.

Using the engineering cost estimates, estimated natural gas product recovery, and natural gas product price assumptions, the net annual engineering cost savings is estimated for the proposed NSPS at about $45 million in 2008 dollars. Totals may not sum due to independent rounding.

As the price assumption is very influential on estimated annualized engineering costs, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering annualized costs estimate of the proposed NSPS. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook in 2008 dollars, the annualized costs are estimated at about −$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even from an estimated engineering costs perspective is around $3.77/Mcf. A $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about −$230 million under a $5/Mcf price. For further details on this sensitivity analysis, please refer the regulatory impact analysis (RIA) for this rulemaking located in the docket.

H. What are the economic impacts?

The NEMS analysis of energy system impacts for the proposed NSPS option estimates that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly ($0.04 per Mcf in 2008 dollars or 0.9 percent at the wellhead for onshore producers in the lower 48 states) for 2015, the year of analysis. This increase in production and decrease in wellhead price is largely a result of the increased natural gas and condensate recovery as a result of complying with the NSPS. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly ($0.02/barrel in 2008 dollars or less than 0.1 percent at the wellhead for onshore producers in the lower 48 states) in the year of analysis, 2015. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude will not change significantly.

Total CO_2e emissions from energy-related sources are expected to increase about 2.0 million metric tons CO_2e or 0.04 percent under the proposed NSPS, according to the NEMS analysis. This increase is attributable largely to natural gas consumption increases. This estimate does not include CO_2e reductions from the implementation of the controls; these reductions are discussed in more detail in the benefits section that follows.

We did not estimate the energy economy impacts of the proposed NESHAP amendments using NEMS, as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.

I. What are the benefits?

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. These proposed rules combined are anticipated to reduce 38,000 tons of HAP, 540,000 tons of VOC and 3.4 million tons of methane. These pollutants are associated with substantial health effects, welfare effects and climate effects. With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and PM (2.5 microns and less) ($PM_{2.5}$) for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.

This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAP of concern from the oil and natural gas sector is benzene, which is a known human carcinogen, and formaldehyde, which is a probable human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006[41] and U.S. EPA, 2010[42]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects such as premature mortality for adults and infants, cardiovascular morbidity, such as heart attacks, hospital admissions and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[43] Ozone is associated with health effects such as respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[44]

In addition to the improvements in air quality and resulting benefits to human health and non-climate welfare effects previously discussed, this proposed rule is expected to result in significant climate co-benefits due to anticipated methane reductions. Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the

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[41] U.S. EPA. RIA. *National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205-Benefits.pdf.*

[42] U.S. EPA. RIA. *National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[43] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[44] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (2007), methane is the second leading long-lived climate forcer after CO_2 globally. Total methane emissions from the oil and gas industry represent about 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2e emissions in the United States, with natural gas systems being the single largest contributor to United States anthropogenic methane emissions.[45] Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which, over time, leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise, among other impacts.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternatives proposed for the NESHAP and the NSPS are expected to reduce methane emissions annually by about 3.4 million short tons or 65 million metric tons CO_2e. After considering the secondary impacts of this proposal previously discussed, such as increased CO_2 emissions from well completion combustion and decreased CO_2e emissions because of fuel-switching by consumers, the methane reductions become about 62 million metric tons CO_2e. These reductions represent about 26 percent of the baseline methane emissions for this sector reported in the EPA's U.S. Greenhouse Gas Inventory Report for 2009 (251.55 million metric tons CO_2e when petroleum refineries and petroleum transportation are excluded because these sources are not examined in this proposal). After considering the secondary impacts of this proposal, such as increased CO_2 emissions from well completion combustion and decreased CO_2 emissions because of fuel-switching by consumers, the CO_2e GHG reductions are reduced to about 62 million metric tons CO_2e. However, it is important to note that the emission reductions are based upon predicted activities in 2015; the EPA did not forecast sector-level emissions in 2015 for this rulemaking. These emission reductions equate to the climate benefits of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[46]

The EPA recognizes that the methane reductions proposed in this rule will provide for significant economic climate benefits to society just described. However, there is no interagency-accepted methodology to place monetary values on these benefits. A 'global warming potential (GWP) approach' of converting methane to CO_2e using the GWP of methane provides an approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group to generate monetized estimates of the benefits.

The social cost of carbon is an estimate of the net present value of the flow of monetized damages from a 1-metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by 1 ton). For more information about the social cost of carbon, see the *Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*[47] and RIA for the Light-Duty Vehicle GHG rule.[48] Applying this approach to the methane reductions estimated for the proposed NESHAP and NSPS of the oil and gas rule, the 2015 climate co-benefits vary by discount rate and range from about $370 million to approximately $4.7 billion; the mean social cost of carbon at the 3-percent discount rate results in an estimate of about $1.6 billion in 2015.

The ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7–10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional and highly speculative. There is no *a priori* reason why domestic benefits should be a constant fraction of net global damages over time.[49]

These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced, depending upon the discount rate assumed with a per ton estimate of $480 at the 3-percent discount rate. Methane climate co-benefit estimates for additional regulatory alternatives are included in the RIA for this proposed rule. These social cost of methane benefit estimates are not the same as would be derived from direct computations (using the integrated assessment models employed to develop the Interagency Social Cost of Carbon estimates) for a variety of reasons, including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases.

Methane is a precursor to ozone and ozone is a short-lived climate forcer that contributes to global warming. The use of the *IPCC Second Assessment Report GWP* to approximate co-benefits may underestimate the direct radiative forcing benefits of reduced ozone levels and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent EPA National Center of Environmental Economics working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases.[50] This conclusion is reached using the 100-year GWP for methane of 25 as put forth in the *IPCC Fourth Assessment Report (AR 4),* as opposed to the lower

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[45] U.S. EPA (2011), *2011 U.S. Greenhouse Gas Inventory Report* Executive Summary available on the internet at *http://www.epa.gov/climateexchange/emissions/downloads11/US-GHG-Inventory-2011-Executive Summary.pdf.*

[46] U.S. EPA. *Greenhouse Gas Equivalency Calculator* available at: *http://www.epa.gov/cleanenergy/energy-resources/calculator.html* accessed 07/19/11.

[47] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Docket ID EPA–HQ–OAR–2009–0472–114577. *http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf;* Accessed March 30, 2011.

[48] U.S. EPA. *Final Rulemaking: Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards.* May 2010. Available on the Internet at *http://www.epa.gov/otaq/climate/regulations.htm#finalR.*

[49] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.*

[50] Marten and Newbold (2011), Estimating the Social Cost of Non-CO_2 *GHG Emissions: Methane and Nitrous Oxide,* NCEE Working Paper Series #11–01. *http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01?OpenDocument.*

value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the *IPCC Assessment Report (AR4)* suggested a GWP of 25 for methane, the EPA has used GWP of 21 to estimate the methane climate co-benefits for this oil and gas proposal in order to provide estimates more consistent with global GHG inventories, which currently use GWP from the *IPCC Second Assessment Report.*

Due to the uncertainties involved with the 'GWP approach' estimates presented and methane climate co-benefits estimates available in the literature, the EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce these estimates until the Interagency Social Cost of Carbon Work Group develops values for non-CO_2 GHG. The EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate benefits of methane reductions. In particular, the EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency-modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined earlier in this notice. These comments will be considered in developing the final rule for this rulemaking.

For the proposed NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health, ecosystem and climate benefits from the reductions in VOC and methane emissions are assumed to be zero. Even though emission reductions of VOC and methane are co-benefits for the proposed NESHAP amendments, they are legitimate components of the total benefit-cost comparison. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the co-benefits to exceed the costs. All estimates are in 2008 dollars. For the proposed NSPS, the revenue from additional product recovery exceeds the costs, which renders a break-even analysis unnecessary when these revenues are included in the analysis. Based on the methodology from Fann, Fulcher, and Hubbell (2009),[51] ranges of benefit-per-ton estimates for emissions of VOC indicate that on average in the United States, VOC emissions are valued from $1,200 to $3,000 per ton as a $PM_{2.5}$ precursor, but emission reductions in specific areas are valued from $280 to $7,000 per ton in 2008 dollars. As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the national average, there is a reasonable chance that the benefits of the rule would exceed the costs, especially if we were able to monetize all of the additional benefits associated with ozone formation, visibility, HAP and methane.

IX. Request for Comments

We are soliciting comments on all aspects of this proposed action. All comments received during the comment period will be considered. In addition to general comments on the proposed actions, we are also interested in any additional data that may help to reduce the uncertainties inherent in the risk assessments. We are specifically interested in receiving corrections to the datasets used for MACT analyses and risk modeling. Such data should include supporting documentation in sufficient detail to allow characterization of the quality and representativeness of the data or information. Please see the following section for more information on submitting data.

X. Submitting Data Corrections

The facility-specific data used in the source category risk analyses, facility-wide analyses and demographic analyses for each source category subject to this action are available for download on the RTR Web page at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* These data files include detailed information for each HAP emissions release point at each facility included in the source category and all other HAP emissions sources at these facilities (facility-wide emissions sources). However, it is important to note that the source category risk analysis included only those emissions tagged with the MACT code associated with the source category subject to the risk analysis.

If you believe the data are not representative or are inaccurate, please identify the data in question, provide your reason for concern and provide any ''improved'' data that you have, if available. When you submit data, we request that you provide documentation of the basis for the revised values to support your suggested changes. To submit comments on the data downloaded from the RTR Web page, complete the following steps:

1. Within this downloaded file, enter suggested revisions to the data fields appropriate for that information. The data fields that may be revised include the following:

Data element	Definition
Control Measure	Are control measures in place? (yes or no).
Control Measure Comment	Select control measure from list provided and briefly describe the control measure.
Delete	Indicate here if the facility or record should be deleted.
Delete Comment	Describes the reason for deletion.
Emission Calculation Method Code for Revised Emissions.	Code description of the method used to derive emissions. For example, CEM, material balance, stack test, etc.
Emission Process Group	Enter the general type of emission process associated with the specified emission point.
Fugitive Angle	Enter release angle (clockwise from true North); orientation of the y-dimension relative to true North, measured positive for clockwise starting at 0 degrees (maximum 89 degrees).
Fugitive Length	Enter dimension of the source in the east-west (x-) direction, commonly referred to as length (ft).

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[51] Fann, N., C.M. Fulcher, B.J. Hubbell. *The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution.* Air Qual Atmos Health (2009) 2:169–176.

Data element	Definition
Fugitive Width	Enter dimension of the source in the north-south (y-) direction, commonly referred to as width (ft).
Malfunction Emissions	Enter total annual emissions due to malfunctions (TPY).
Malfunction Emissions Max Hourly	Enter maximum hourly malfunction emissions here (lb/hr).
North American Datum	Enter datum for latitude/longitude coordinates (NAD27 or NAD83); if left blank, NAD83 is assumed.
Process Comment	Enter general comments about process sources of emissions.
REVISED Address	Enter revised physical street address for MACT facility here.
REVISED City	Enter revised city name here.
REVISED County Name	Enter revised county name here.
REVISED Emission Release Point Type	Enter revised Emission Release Point Type here.
REVISED End Date	Enter revised End Date here.
REVISED Exit Gas Flow Rate	Enter revised Exit Gas Flowrate here (ft^3/sec).
REVISED Exit Gas Temperature	Enter revised Exit Gas Temperature here (OF).
REVISED Exit Gas Velocity	Enter revised Exit Gas Velocity here (ft/sec).
REVISED Facility Category Code	Enter revised Facility Category Code here, which indicates whether facility is a major or area source.
REVISED Facility Name	Enter revised Facility Name here.
REVISED Facility Registry Identifier	Enter revised Facility Registry Identifier here, which is an ID assigned by the EPA Facility Registry System.
REVISED HAP Emissions Performance Level Code	Enter revised HAP Emissions Performance Level here.
REVISED Latitude	Enter revised Latitude here (decimal degrees).
REVISED Longitude	Enter revised Longitude here (decimal degrees).
REVISED MACT Code	Enter revised MACT Code here.
REVISED Pollutant Code	Enter revised Pollutant Code here.
REVISED Routine Emissions	Enter revised routine emissions value here (TPY).
REVISED SCC Code	Enter revised SCC Code here.
REVISED Stack Diameter	Enter revised Stack Diameter here (ft).
REVISED Stack Height	Enter revised Stack Height here (Ft).
REVISED Start Date	Enter revised Start Date here.
REVISED State	Enter revised state here.
REVISED Tribal Code	Enter revised Tribal Code here.
REVISED Zip Code	Enter revised Zip Code here.
Shutdown Emissions	Enter total annual emissions due to shutdown events (TPY).
Shutdown Emissions Max Hourly	Enter maximum hourly shutdown emissions here (lb/hr).
Stack Comment	Enter general comments about emission release points.
Startup Emissions	Enter total annual emissions due to startup events (TPY).
Startup Emissions Max Hourly	Enter maximum hourly startup emissions here (lb/hr).
Year Closed	Enter date facility stopped operations.

2. Fill in the commenter information fields for each suggested revision (*i.e.,* commenter name, commenter organization, commenter e-mail address, commenter phone number and revision comments).

3. Gather documentation for any suggested emissions revisions (*e.g.,* performance test reports, material balance calculations, etc.).

4. Send the entire downloaded file with suggested revisions in Microsoft® Access format and all accompanying documentation to Docket ID Number EPA–HQ–OAR–2010–0505 (through one of the methods described in the ADDRESSES section of this preamble). To expedite review of the revisions, it would also be helpful if you submitted a copy of your revisions to the EPA directly at *RTR@epa.gov* in addition to submitting them to the docket.

5. If you are providing comments on a facility with multiple source categories, you need only submit one file for that facility, which should contain all suggested changes for all source categories at that facility. We request that all data revision comments be submitted in the form of updated Microsoft® Access files, which are provided on the *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html* Web page.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 8 shows the results of the cost and benefits analysis for these proposed rules. For more information on the benefit and cost analysis, as well as details on the regulatory options considered, please refer to the RIA for this rulemaking, which is available in the docket.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, COSTS AND NET BENEFITS FOR THE PROPOSED OIL AND NATURAL GAS NSPS AND NEHSAP AMENDMENTS IN 2015

[Millions of 2008$][1]

	Proposed NSPS	Proposed NESHAP amendments	Proposed NSPS and NESHAP amendments combined
Total Monetized Benefits[2]	N/A	N/A	N/A.
Total Costs[3]	−$45 million	$16 million	−$29 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits[4 5]	37,000 tons of HAP 540,000 tons of VOC 3.4 million tons of methane	1,400 tons of HAP 9,200 tons of VOC 4,900 tons of methane	38,000 tons of HAP. 540,000 tons of VOC. 3.4 million tons of methane.
	Health effects of HAP exposure. Health effects of PM$_{2.5}$ and ozone exposure. Visibility impairment. Vegetation effects. Climate effects.		

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone and PM, as well as climate effects associated with methane, we have determined that quantification of those benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.

[3] The engineering compliance costs are annualized using a 7-percent discount rate. The negative cost for the proposed NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS.

[4] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, PM$_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits.

[5] The specific control technologies for these proposed rules are anticipated to have minor secondary disbenefits. The net CO$_2$-equivalent emission reductions are 93,000 metric tons for the NESHAP and 62 million metric tons for the NSPS.

B. Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.* The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH) and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, burden changes associated with these amendments result from the respondents' annual reporting and recordkeeping burden associated with this proposed rule for this collection (averaged over the first 3 years after the effective date of the standards). The burden is estimated to be 560,000 labor hours at a cost of $18 million per year. This includes the burden previously estimated for sources subject to 40 CFR part 60, subpart KKK (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response, based on an average of 1,459 operators responding per year and 16 responses per year.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the Oil and Natural Gas Production NESHAP to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the Natural Gas Transmission and Storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions and information gathering. Recordkeeping cost estimates include reading instructions, planning activities and conducting compliance monitoring. The average hours and cost per regulated entity subject to the Oil and Natural Gas Production NESHAP would be 72 hours per year and $2,500 per year, based on an average of 846 facilities per year and three responses per facility. For the Natural Gas Transmission and Storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year, based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID Number EPA–HQ–OAR–2010–0505. Submit any comments related to the ICR to the EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to the

EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after August 23, 2011, a comment to OMB is best assured of having its full effect if OMB receives it by September 22, 2011. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Proposed NSPS

After considering the economic impact of the proposed NSPS on small entities, I certify that this action will not have a SISNOSE. The EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in the RIA, which is in the Docket, EPA concludes the number of impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to REC activities occur without a significant time lag between implementing the control and obtaining the recovered product, unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

Proposed NESHAP Amendments

After considering the economic impact of the proposed NESHAP amendments on small entities, I certify that this action will not have a SISNOSE. Based upon the analysis in the RIA, which is in the Docket, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. The EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, *10 firms (16 percent)* are likely to have impacts greater than 1 percent. Four of these *10* firms are likely to have impacts greater than 3 percent. While these *10* firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, the EPA, nonetheless, has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of title II of the *Unfunded Mandates Reform Act of 1995* (UMRA), 2 U.S.C. 1531–1538 for state, local or tribal governments or the private sector. This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA. This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This action contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule. In the spirit of Executive Order 13132 and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed rule from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effect on tribal governments, on the relationship between the Federal government and Indian tribes or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This proposed rule is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This actions' health and risk assessments are contained in section VII.C of this preamble.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to HAP from oil and natural gas sector activities.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.''

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution or use of energy. As such, the proposed NESHAP amendments are not ''significant energy actions'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant effect on the supply, distribution or use of energy. As such, the proposed NSPS is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

As discussed in the impacts section of the Preamble, we use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the United States DOE and is used to produce the *Annual Energy Outlook,* a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

For more information on the estimated energy effects, please refer to the economic impact analysis for this proposed rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. Also, we are proposing to revise subpart HHH to allow ASTM D6420–99 (2004), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final Oil and Natural Gas Production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420–99 (2004) for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420–99 (2004). This would allow the continued use of gas chromatography configurations other than gas chromatography/mass spectrometry.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on EJ. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the United States.

The EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.C of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health. Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that, although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

40 CFR Part 63

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: July 28, 2011.

Lisa P. Jackson,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

2. Section 60.17 is amended by:

a. Revising paragraph (a)(7); and

b. Revising paragraphs (a)(91) and (a)(92) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h) and 60.5401(h).

* * * * *

(91) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f) and 60.5400(f).

(92) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f), 60.5400(f) and 60.5406(b).

* * * * *

Subpart KKK—Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

3. The heading for Subpart KKK is revised to read as set out above.

4. Section 60.630 is amended by revising paragraph (b) to read as follows:

§ 60.630 Applicability and designation of affected facility.

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011, is subject to the requirements of this subpart.

* * * * *

Subpart LLL—Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

5. The heading for Subpart LLL is revised to read as set out above.

6. Section 60.640 is amended by revising paragraph (d) to read as follows:

§ 60.640 Applicability and designation of affected facilities.

* * * * *

(d) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

* * * * *

7. Add subpart OOOO to part 60 to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commenced construction, modification or reconstruction after August 23, 2011.

§ 60.5365 Am I subject to this subpart?

If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.

(a) A gas wellhead affected facility, is a single natural gas well.

(b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor located between the wellhead and the city gate (as defined in § 60.5430), except that a centrifugal compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.

(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor located between the wellhead and the city gate (as defined in § 60.5430), except that a reciprocating compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.

(d) A pneumatic controller affected facility, which is defined as a single pneumatic controller.

(e) A storage vessel affected facility, which is defined as a single storage vessel.

(f) Compressors and equipment (as defined in § 60.5430) located at onshore natural gas processing plants.

(1) Each compressor in VOC service or in wet gas service is an affected facility.

(2) The group of all equipment, except compressors, within a process unit is an affected facility.

(3) Addition or replacement of equipment, as defined in § 60.5430, for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(4) Equipment (as defined in § 60.5430) associated with a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment (as defined in § 60.5430) not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart.

(5) Affected facilities located at onshore natural gas processing plants and described in paragraphs (f)(1) and (f)(2) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located onshore that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and paragraphs 60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, and §§ 60.5410(g), 60.5415(g), and § 60.5423 of this subpart.

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown, and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5375 What standards apply to gas wellhead affected facilities?

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing, as defined in § 60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section.

(1) You must minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.

(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.

(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

(b) You must maintain a log for each well completion operation at each gas wellhead affected facility. The log must be completed on a daily basis and must contain the records specified in § 60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

(f) For wells meeting the criteria for wildcat or delineation wells, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(3) of this section. You must also maintain records specified in § 60.5420(c)(1)(iii) for wildcat or delineation wells.

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section, as applicable for each centrifugal compressor affected facility.

(a) You must equip each rotating compressor shaft with a dry seal system upon initial startup.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later.

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b) or (c) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) are exempt from this requirement.

(a) The requirements of paragraph (b) or (c) of this section are not required if you demonstrate, to the Administrator's satisfaction, that the use of a high bleed device is predicated. The demonstration may include, but is not limited to, response time, safety and actuation.

(b) Each pneumatic controller affected facility located at a natural gas processing plant (as defined in § 60.5430) must have zero emissions of natural gas.

(c) Each pneumatic controller affected facility not located at a natural gas processing plant (as defined in § 60.5430) must have natural gas emissions no greater than 6 standard cubic feet per hour.

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a).

§ 60.5395 What standards apply to storage vessel affected facilities?

You must comply with the standards in paragraphs (a) through (e) of this section for each storage vessel affected facility.

(a) You must comply with the standards for storage vessels specified in § 63.766(b) and (c) of this chapter, except as specified in paragraph (b) of this section. Storage vessels that meet either one or both of the throughput conditions specified in paragraphs (a)(1) or (a)(2) of this section are not subject to the standards of this section.

(1) The annual average condensate throughput is less than 1 barrel per day per storage vessel.

(2) The annual average crude oil throughput is less than 20 barrels per day per storage vessel.

(b) This standard does not apply to storage vessels already subject to and controlled in accordance with the requirements for storage vessels in § 63.766(b)(1) or (2) of this chapter.

(c) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5400 What VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to each compressor in VOC service or in wet gas service and the group of all equipment (as defined in § 60.5430), except compressors, within a process unit.

(a) You must comply with the requirements of § 60.482–1a(a), (b), and (d), § 60.482–2a, and § 60.482–4a through 60.482–11a, except as provided in § 60.5401.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402 of this subpart.

(d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–63, 77, or 93, E168–67, 77, or 92, or E260–73, 91, or 96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401 What are the exceptions to the VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 5000 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant with a design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section.

(f) Flares used to comply with this subpart must comply with the requirements of § 60.18.

(g) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

§ 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$X - KQ_a\gamma$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole) / ((24.04 dscm/kg-mole) (1000 kg S/Mg))

= 1.331×10^{-3} Mg/dscm, for metric units

= (32 lb S/lb-mole) / ((385.36 dscf/lb-mole) (2240 lb S/long ton))

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E–260 (incorporated by reference—see § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)\frac{\square}{S + E}$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage tanks. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO_2 + reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of Appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of Appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage tanks with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is

within ± 20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ± 20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(3).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere.* The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ± 1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock internal. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

§ 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure? [1]

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 $(D - C)$

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

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[1] Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

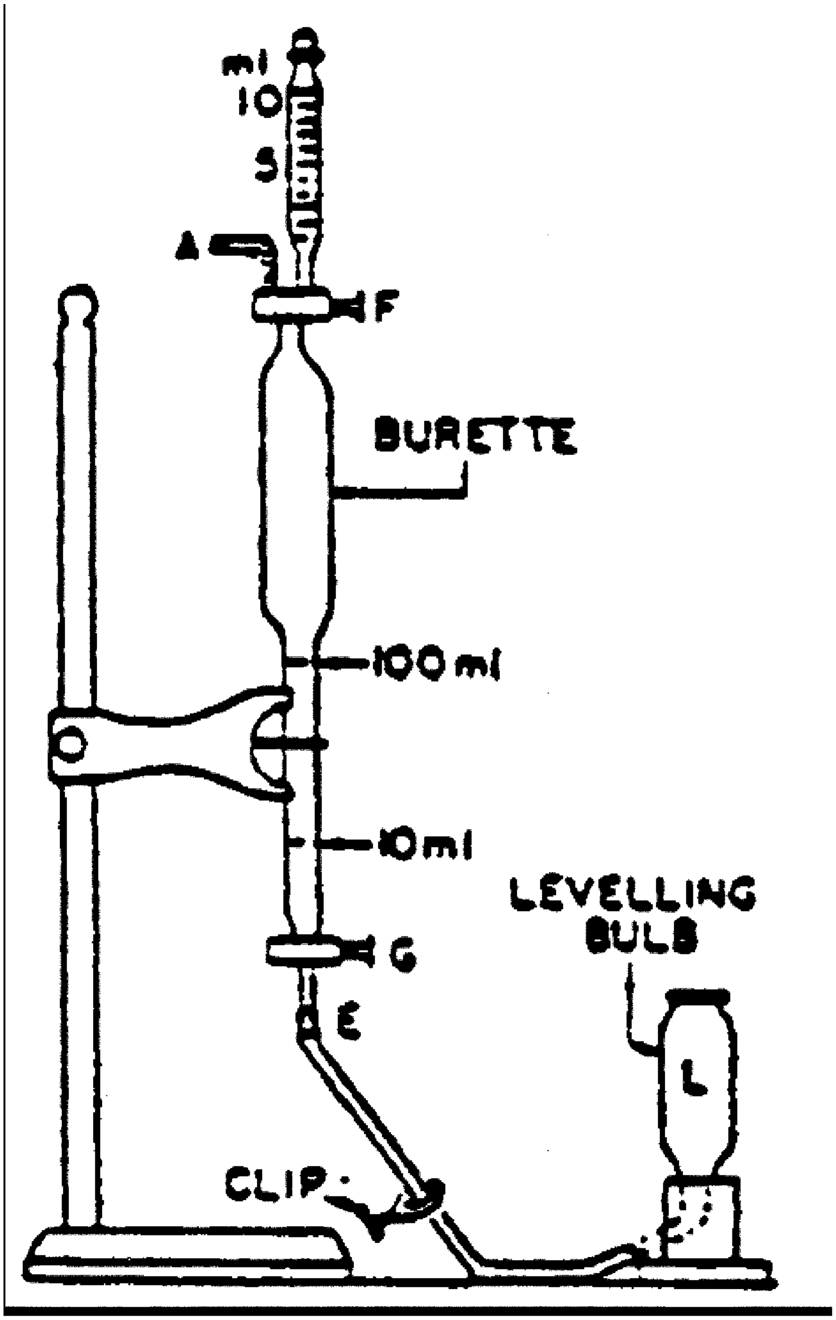

Figure 1. Tutwiler burette (lettered items mentioned in text).

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§ 60.5410 How do I demonstrate initial compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later, and ends on the date the first annual report is due as specified in § 60.5420(b).

(a) You have achieved initial compliance with standards for each well completion operation conducted at your gas wellhead affected facility if you have complied with paragraphs (a)(1) and (a)(2) of this section.

(1) You have notified the Administrator within 30 days of the commencement of the well completion operation, the date of the commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

(2) You have maintained a log of records as specified in § 60.5375(b) or (f) for each well completion operation conducted during the initial compliance period.

(3) You have submitted the initial annual report for your wellhead affected facility as required in § 60.5420(b).

(b) You have achieved initial compliance with standards for your centrifugal compressor affected facility if the centrifugal compressor is fitted with a dry seal system upon initial startup as required by § 60.5380.

(c) You have achieved initial compliance with standards for each reciprocating compressor affected facility if you have complied with paragraphs (c)(1) and (c)(2) of this section.

(1) During the initial compliance period, you have continuously monitored the number of hours of operation.

(2) You have included the cumulative number of hours of operation for your reciprocating compressor affected facility during the initial compliance period in your initial annual report required in § 60.5420(b).

(d) You have achieved initial compliance with emission standards for your pneumatic controller affected facility if you comply with the requirements specified in paragraphs (d)(1) through (d)(4) of this section.

(1) You have demonstrated, to the Administrator's satisfaction, the use of a high bleed device is predicated as specified in § 60.5490(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven other than by use of natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility not located at a natural gas processing plant and the manufacturer's design specifications guarantee the controller emits less than or equal to 6.0 standard cubic feet of gas per hour.

(4) You have included the information in paragraphs (d)(1) through (d)(3) of this section in the initial annual report submitted for your pneumatic controller affected facilities according to the requirements of § 60.5420(b).

(e) You have demonstrated initial compliance with emission standards for your storage vessel affected facility if you are complying with paragraphs (e)(1) through (e)(7) of this section.

(1) You have equipped the storage vessel with a closed vent system that meets the requirements of § 63.771(c) of this chapter connected to a control device that meets the conditions specified in § 63.771(d).

(2) You have conducted an initial performance test as required in § 63.772(e) of this chapter within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in § 63.772(f).

(3) You have conducted the initial inspections required in § 63.773(c) of this chapter.

(4) You have installed and operated continuous parameter monitoring systems in accordance with § 63.773(d) of this chapter.

(5) If you are exempt from the standards of § 60.5395 according to § 60.5395(a)(1) or (a)(2), you have determined the condensate or crude oil throughput, as applicable, according to paragraphs (e)(5)(i) or (e)(5)(ii) of this section and demonstrated to the Administrator's satisfaction that your annual average condensate throughput is less than 1 barrel per day per tank and your annual average crude oil throughput is less than 20 barrels per day per tank.

(i) You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications.

(ii) You have used any other method approved by the Administrator to determine annual average condensate or crude oil throughput.

(6) You have submitted the information in paragraphs (e)(1) through (e)(5) of this section in the initial annual report for your storage vessel affected facility as required in § 60.5420(b).

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (g)(3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (g)(1)(ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (g)(2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas wellhead affected facility, you must demonstrate continuous compliance by maintaining the records for each completion operation (as defined in § 60.5430) specified in § 60.5420.

(b) For each centrifugal compressor affected facility, continuous compliance is demonstrated if the rotating compressor shaft is equipped with a dry seal.

(c) For each reciprocating compressor affected facility, you have demonstrated continuous compliance according to paragraphs (c)(1) and (2) of this section

(1) You have continuously monitored the number of hours of operation for each reciprocating compressor affected facility since initial startup, or the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. The cumulative number of hours of operation must be included in the annual report as required in § 60.5420(b)(4).

(2) You have replaced the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours.

(d) For each pneumatic controller affected facility, continuous compliance is demonstrated by maintaining the records demonstrating that you have installed and operated the pneumatic controllers as required in § 60.5390(a), (b) or (c).

(e) For each storage vessel affected facility, continuous compliance is demonstrated according to § 63.772(f) of this chapter.

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in

§ 60.5405(b) according to paragraphs (g)(1) and (g)(2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(h) *Affirmative defense for exceedance of emission limit during malfunction.* In response to an action to enforce the standards set forth in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at § 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in § 60.5420(a), and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, and 60.5400 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4), and according to paragraphs (a)(1) and (a)(2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365. For the purposes of this subpart, a workover that occurs after August 23, 2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under § 60.7(a)(4).

(1) If you own or operate a pneumatic controller affected facility you are not required to submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4).

(2) If you own or operate a gas wellhead affected facility, you must submit a notification to the Administrator within 30 days of the commencement of the well completion operation. The notification must include the date of commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due 1 year after the initial startup date for your affected facility or 1 year after the date of publication of the final rule in the **Federal Register,** whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

(1) The general information specified in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(2) For each gas wellhead affected facility, the information in paragraphs (b)(2)(i) through (b)(2)(iii) of this section.

(i) An identification of each well completion operation, as defined in § 60.5430, for each gas wellhead affected facility conducted during the reporting period;

(ii) A record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375 for each gas well affected facility.

(iii) Records specified in § 60.5375(b) for each well completion operation that occurred during the reporting period.

(3) For each centrifugal compressor affected facility installed during the reporting period, documentation that the centrifugal compressor is equipped with dry seals.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.

(i) The cumulative number of hours or operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Documentation that the reciprocating compressor rod packing was replaced before the cumulative number of hours of operation reached 24,000 hours.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) The date, location and manufacturer specifications for each pneumatic controller installed.

(ii) If applicable, documentation that the use of high bleed pneumatic devices is predicated and the reasons why.

(iii) For pneumatic controllers not installed at a natural gas processing plant, the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.

(iv) For pneumatic controllers installed at a natural gas processing plant, documentation that each controllers has zero natural gas emissions.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.

(i) If required to reduce emissions by complying with § 60.5395(a)(1), the records specified in § 63.774(b)(2) through (b)(8) of this chapter.

(ii) Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in § 60.5395(a)(1) or (a)(2).

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

(1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).

(i) Records identifying each well completion operation for each gas wellhead affected facility conducted during the reporting period;

(ii) Record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375.

(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (c)(1)(iii)(B) of this section.

(A) For each gas wellheads affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the duration of flowback; duration of recovery to the sales line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas wellhead affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.

(2) For each centrifugal compressor affected facility, you must maintain records on the type of seal system installed.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) Records of the cumulative number of hours of operation since initial startup or the date of publication of the final rule in the **Federal Register**, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (c)(4)(iv) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller installed.

(ii) Records of the determination that the use of high bleed pneumatic devices is predicated and the reasons why.

(iii) If the pneumatic controller affected facility is not located at a natural gas processing plant, records of the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.

(iv) If the pneumatic controller affected facility is located at a natural gas processing plant, records of the documentation that only instrument air controllers are used.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) If required to reduce emissions by complying with § 63.766, the records specified in § 63.774(b)(2) through (8) of this chapter.

(ii) Records of the determination that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under § 60.5395(a)(1) and (a)(2).

§ 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) ''Above 500 ppm'' if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) ''Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3).

§ 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405(a) and (b) and § 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions.

(b) You must submit a written report of excess emissions to the Administrator semiannually. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

§ 60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Centrifugal compressor means a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers.

Compressor means a piece of equipment that compresses process gas and is usually a centrifugal compressor or a reciprocating compressor.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Condensate means a hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in § 60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate.

Crude oil means crude petroleum oil or any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used to transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame.

Flowback means the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.

Flow line means surface pipe through which oil and/or natural gas travels from the well.

Gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well means a well, the principal production of which at the mouth of the well is gas.

High-bleed pneumatic devices means automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Hydraulic fracturing means the process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(h)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low-bleed pneumatic controller means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non gas-driven pneumatic device means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Plunger lift system means an intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reduced emissions completion means a well completion where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line.

Reduced emissions recompletion means a well completion following refracturing of a gas well where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Routed to a process or route to a process means the emissions are conveyed to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas.

Sales line means pipeline, generally small in diameter, used to transport oil or gas from the well to a processing facility or a mainline pipeline.

Storage vessel means a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 tpy.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage tank means a storage tank stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment.

Well completion operation means any well completion or well workover occurring at a gas wellhead affected facility.

Well site means the areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

TABLE 1 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 ≤ X ≤ 5.0	5.0 < X ≤ 15.0	15.0 < X ≤ 300.0	X > 300.0
Y ≥ 50	79.0	88.51$X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller		
20 ≤ Y < 50	79.0	88.5$X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
10 ≤ Y < 20	79.0	88.5$X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

TABLE 2 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 ≤ X ≤ 5.0	5.0 < X ≤ 15.0	15.0 < X ≤ 300.0	X > 300.0
Y ≥ 50	74.0	85.35$X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller		
20 ≤ Y < 50	74.0	85.35$X^{0.0144}Y^{0.0128}$ or 97.9, whichever is smaller		97.5
10 ≤ Y < 20	74.0	85.35$X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

E = The sulfur emission rate expressed as elemental sulfur, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.

R = The sulfur emission reduction efficiency achieved in percent, carried to one decimal place.

S = The sulfur production rate, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

[As stated in § 60.5425, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes.	Additional terms defined in § 60.5430.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420(a).

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO—Continued

[As stated in § 60.5425, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.8	Performance tests	No	Performance testing is required for storage vessels as specified in 40 CFR part 63, subpart HH.
§ 60.9	Availability of information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOO.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	Yes.	
§ 60.19	General notification and reporting requirement	Yes.	

PART 63—[AMENDED]

8. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

9. Section 63.14 is amended by:

a. Adding paragraphs (b)(69), (b)(70), (b)(71) and (b)(72); and

b. Revising paragraph (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

* * * * *

(69) ASTM D1945–03(2010) Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §§ 63.772 and 63.1282.

(70) ASTM D5504–08 Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 63.772 and 63.1282.

(71) ASTM D3588–98(2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, IBR approved for §§ 63.772 and 63.1282.

(72) ASTM D4891–89(2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for §§ 63.772 and 63.1282.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981 IBR approved for §§ 63.309(k)(1)(iii), 63.771(e), 63.865(b), 63.1281(d), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), 63.11646(a)(1)(iii), table 5 to subpart DDDDD of this part, and table 1 to subpart ZZZZZ of this part.

* * * * *

Subpart HH—[Amended]

10. Section 63.760 is amended by:

a. Revising paragraph (a)(1) introductory text;

b. Revising paragraph (a)(1)(iii);

c. Revising paragraph (a)(2);

d. Revising paragraph (b)(1)(ii);

e. Revising paragraph (f) introductory text;

f. Revising paragraph (f)(1);

g. Revising paragraph (f)(2); and

h. Adding paragraphs (f)(7), (f)(8), (f)(9) and (f)(10) to read as follows:

§ 63.760 Applicability and designation of affected source.

(a) * * *

(1) Facilities that are major or area sources of hazardous air pollutants (HAP) as defined in § 63.761. Emissions for major source determination purposes can be estimated using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (iii) of this section. As an alternative to calculating the maximum natural gas or hydrocarbon liquid throughput, the owner or operator of a new or existing source may use the facility's design maximum natural gas or hydrocarbon liquid throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels, and becomes a major source, must comply thereafter with all provisions of this subpart applicable to a major source starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(iii) The owner or operator shall determine the maximum values for other parameters used to calculate emissions as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in accordance with paragraph (a)(1)(i)(A) or (B) of this section. Parameters, other than glycol circulation rate, shall be based on either highest measured values or annual average. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point where hydrocarbon liquids enter either the Organic Liquids Distribution (Non-gasoline) or Petroleum Refineries source categories.

* * * * *

(b) * * *

(1) * * *

(ii) Each storage vessel;

* * * * *

(f) The owner or operator of an affected major source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1), (f)(2), and (f)(7) through (f)(10) of this section. The owner or operator of an affected area source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(3) through (f)(6) of this section.

(1) Except as specified in paragraphs (f)(7) through (10) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the applicable provisions of this subpart no later than June 17, 2002, except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (f)(7) through (10) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the applicable provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, other than production field facilities identified in (f)(9) of this section, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

* * * * *

(7) Each affected small glycol dehydration unit and each storage vessel that is not a storage vessel with the potential for flash emissions located at a major source, that commenced construction before August 23, 2011 must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(8) Each affected small glycol dehydration unit and each storage vessel that is not a storage vessel with the potential for flash emissions, both as defined in § 63.761, located at a major source, that commenced construction on or after August 23, 2011 must achieve compliance immediately upon initial startup or the date of publication of the final rule in the **Federal Register**, whichever is later.

(9) A production field facility, as defined in § 63.761, constructed before August 23, 2011 that was previously determined to be an area source but becomes a major source (as defined in paragraph 3 of the major source definition in § 63.761) on the date of publication of the final rule in the **Federal Register** must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(10) Each large glycol dehydration unit, as defined in § 63.761, that has complied with the provisions of this subpart prior to August 23, 2011 by reducing its benzene emissions to less than 0.9 megagrams per year must achieve compliance no later than 90 days after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

* * * * *

11. Section 63.761 is amended by:

a. Adding, in alphabetical order, new definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units'' and ''small glycol dehydration units'';

b. Revising the definitions for ''associated equipment,'' ''facility,'' ''glycol dehydration unit baseline operations,'' and ''temperature monitoring device''; and

c. Revising paragraph (3) of the definition for ''major source'' to read as follows:

§ 63.761 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Associated equipment, as used in this subpart and as referred to in section 112(n)(4) of the Act, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Facility means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored; or where natural gas is processed, upgraded, or stored. For the purpose of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydrator unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90

Mg/yr, determined according to § 63.772(b).

* * * * *

Major source * * *

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 85 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.772(b).

* * * * *

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in °C, or ± 2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

* * * * *

12. Section 63.762 is revised to read as follows:

§ 63.762 Startups and shutdowns.

(a) The provisions set forth in this subpart shall apply at all times.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup or shutdown, of the affected source or a portion thereof.

(c) During startups and shutdowns, the owner or operator shall implement measures to prevent or minimize excess emissions to the maximum extent practical.

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

13. Section 63.764 is amended by:

a. Revising paragraph (c)(2) introductory text;

b. Revising paragraph (e)(1) introductory text;

c. Revising paragraph (i); and

d. Adding paragraph (j) to read as follows:

§ 63.764 General standards.

* * * * *

(c) * * *

(2) For each storage vessel subject to this subpart, the owner or operator shall comply with the requirements specified in paragraphs (c)(2)(i) through (iii) of this section.

* * * * *

(e) *Exemptions.* (1) The owner or operator of an area source is exempt from the requirements of paragraph (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in § 63.774(d)(1).

* * * * *

(i) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(j) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

14. Section 63.765 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b)(1);

c. Revising paragraph (c)(2); and

d. Revising paragraph (c)(3) to read as follows:

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i), (ii), or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.761, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(ii) The owner or operator of a glycol dehydration unit located at an area source, that must be controlled as specified in § 63.764(d)(1)(i), shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. The limit must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 1.10x10^{-4} * Throughput * C_{i,BTEX} * 365\,\frac{days}{yr} * \frac{1\,Mg}{1x10^{6}\,grams}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

1.10×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter = ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.771(e).

(C) Meet the emissions limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.771(e) and emissions in accordance with the requirements specified in § 63.772(b)(2).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i), (ii), or (iii) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For area source dehydration units, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by paragraph (b)(1)(iii) of this section.

15. Section 63.766 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b) introductory text;

c. Revising paragraph (b)(1); and

d. Revising paragraph (d) to read as follows:

§ 63.766 Storage vessel standards.

(a) This section applies to each storage vessel (as defined in § 63.761) subject to this subpart.

(b) The owner or operator of a storage vessel (as defined in § 63.761) shall comply with one of the control requirements specified in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall equip the affected storage vessel with a cover that is connected, through a closed-vent system that meets the conditions specified in § 63.771(c), to a control device or a combination of control devices that meets any of the conditions specified in § 63.771(d). The cover shall be designed and operated in accordance with the requirements of § 63.771(b).

* * * * *

(d) This section does not apply to storage vessels for which the owner or operator is subject to and controlled under the requirements specified in 40

CFR part 60, subpart Kb; or the requirements specified under 40 CFR part 63 subparts G or CC.

16. Section 63.769 is amended by:

a. Revising paragraph (b);

b. Revising paragraph (c) introductory text; and

b. Revising paragraph (c)(8) to read as follows:

§ 63.769 Equipment leak standards.

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or the requirements specified in 40 CFR part 60, subpart KKK.

(c) For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR part 61, subpart V, §§ 61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except for valves subject to § 61.247–2(b) a leak is detected if an instrument reading of 500 ppm or greater is measured.

* * * * *

(8) Flares, as defined in § 63.761, used to comply with this subpart shall comply with the requirements of § 63.11(b).

17. Section 63.771 is amended by:

a. Revising paragraph (c)(1) introductory text;

b. Revising the heading of paragraph (d);

c. Adding paragraph (d) introductory text;

d. Revising paragraph (d)(1)(i) introductory text;

e. Revising paragraph (d)(1)(i)(C);

f. Revising paragraph (d)(1)(ii);

g. Revising paragraph (d)(1)(iii);

h. Revising paragraph (d)(4)(i);

i. Revising paragraph (d)(5)(i);

j. Revising paragraph (e)(2);

k. Revising paragraph (e)(3) introductory text;

l. Revising paragraph (e)(3)(ii); and

m. Adding paragraph (f) to read as follows:

§ 63.771 Control equipment requirements.

* * * * *

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units, shall comply with the control device requirements in paragraph (f) of this section.

(1) * * *

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

* * * * *

(C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 63.772(e), operates at a minimum temperature of 760 degrees C.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under § 63.765, § 63.766, and § 63.769. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.774(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.775(d)(5)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.772(e)(2)(xii).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.765(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.765(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e). If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e); or

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.772(f) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1)(ii) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

18. Section 63.772 is amended by:

a. Revising paragraph (b) introductory text;

b. Revising paragraph (b)(1)(ii);

c. Revising paragraph (b)(2);

d. Adding paragraph (d);

e. Revising paragraph (e) introductory text;

f. Revising paragraphs (e)(1)(i) through (v);

g. Revising paragraph (e)(2);

h. Revising paragraph (e)(3) introductory text;

i. Revising paragraph (e)(3)(i)(B);

j. Revising paragraph (e)(3)(iv)(C)(*1*);

k. Adding paragraphs (e)(3)(v) and (vi);

l. Revising paragraph (e)(4) introductory text;

m. Revising paragraph (e)(4)(i);

n. Revising paragraph (e)(5);

o. Revising paragraph (f) introductory text;

p. Adding paragraphs (f)(2) through (f)(6);

q. Revising paragraph (g) introductory text;

r. Revising paragraph (g)(1) and paragraph (g)(2) introductory text;

s. Revising paragraph (g)(2)(iii);

t. Revising paragraph (g)(3);

u. Adding paragraph (h); and

v. Adding paragraph (i) to read as follows:

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

* * * * *

(b) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (b)(2)(ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in § 63.772(a)(1)(i) or (ii), or an alternative method according to § 63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

* * * * *

(d) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.765(b)(1)(iii), the requirements of paragraph (e) of this section apply. Compliance is demonstrated using the methods specified in paragraph (f) of this section.

(2) If no control device is used to comply with the emission limit in § 63.765(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (d)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (d)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.765(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (e)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(e) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) using a performance test as specified in paragraph (e)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (e)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (e)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (h) of this section can be used.

(1) * * *

(i) Except as specified in paragraph (e)(2) of this section, a flare, as defined in § 63.761, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.761, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), the owner or operator shall use the test methods and procedures specified in paragraphs (e)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (e)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.765(b)(1)(iii), or the BTEX emission limit specified in § 63.771(f)(1) the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.771(f)(1) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (e)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o$$

Where:

E_o= Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj}= Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj}= Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o= Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2= Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (e)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (e)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.760(f)(7) through (8), except that the initial performance test for existing combustion control devices at existing major sources shall be conducted no later than 3 years after the date of publication of the final rule in the **Federal Register**. If the owner or operator of an existing combustion control device at an existing major source chooses to replace such device with a control device whose model is tested under § 63.772(h), then the newly installed device shall comply with all provisions of this subpart no later than 3 years after the date of publication of the final rule in the **Federal Register**. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.775(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (e)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.775(e)(2)(xi). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.772(h), or

(*2*) A combustion control device tested under § 63.772(e) that meets the outlet TOC or HAP performance level specified in § 63.771(d)(1)(i)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC or HAP performance level.

(4) For a condenser design analysis conducted to meet the requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (e)(4)(i) and (e)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.775(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (e)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (e)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(f) *Compliance demonstration for control device performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.771(d)(1)(i), (e)(3) and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (f)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.771(d)(1)(ii), (e)(3) or (f)(1) may demonstrate compliance according to paragraph (g) of this section. An owner or operator may switch between compliance with paragraph (f) of this section and compliance with paragraph (g) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.775(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.773(d)(4) except that the inlet gas flow rate to the control device shall not be averaged.

(3) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (f)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (f)(1) of this section. For inlet gas flow rate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.772(h).

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.773(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(g) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.771(d)(1)(ii),(e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (g)(1) through (3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to § 63.773(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.771(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the requirements in § 63.771(d)(1)(ii),(e)(3) or (f)(1) shall be demonstrated by the procedures in paragraphs (g)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (g)(2)(iii)(A) and (B) of this section, at the end of each operating day, the owner or operator shall calculate the 365-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (g)(2)(ii) of this section for the preceding 365 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.771(e), the 365-day average HAP, or BTEX, emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (g)(2)(ii) of this section, both for the previous 365 operating days.

(A) After the compliance dates specified in § 63.760(f), an owner or operator with less than 120 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the average HAP, or BTEX emission reduction, as appropriate, for the first 120 days of operation after the compliance dates. For sources required to meet the overall 95.0 percent reduction requirement, compliance is achieved if the 120-day average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(B) After 120 days and no more than 364 days of operation after the compliance dates specified in § 63.760(f), the owner or operator shall calculate the average HAP emission reduction as the HAP emission reduction averaged over the number of days between the current day and the applicable compliance date. For sources required to meet the overall 95.0-percent reduction requirement, compliance with the performance requirements is achieved if the average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(3) If the owner or operator has data for 365 days or more of operation, compliance is achieved based on the applicable criteria in paragraphs (g)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.771(d)(1)(ii) or (e)(3) the average HAP emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.771(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (g)(1) of this section.

* * * * *

(h) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (h)(7) of this section by conducting a performance test as specified in paragraphs (h)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (h)(4)(i) through (iii) of this section.

(i) The fuel flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) Inlet flow rate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet fuel sampling shall be conducted in accordance with the criteria in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) At the inlet fuel sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of the THC test.

(*2*) Fill one canister for each THC test run.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each fuel sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(*3*) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504.

(*4*) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (h)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flow rate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (h)(4)(iii)(B), (h)(5)(ii)(A), and (h)(5)(ii)(B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be kneaded or otherwise vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A. The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (h)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (h)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (h)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (h)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(ii) The manufacturer shall determine a maximum inlet gas flow rate which shall not be exceeded for each control device model to achieve the criteria in paragraph (h)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraphs (h)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 98.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (h)(8)(i) through (iii) of this section in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (h)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(i) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (h) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (h) of this section and complying with the following criteria:

(1) The inlet gas flow rate shall meet the range specified by the manufacturer. Flow rate shall be measured as specified in § 63.773(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.773(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed monthly. The observation period shall be 2 hours and shall be used according to Method 22.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flow rate monitored under paragraph (i)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (i)(3) of this section the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test shall follow the requirements in paragraphs (i)(4)(iii)(A) and (B) of this section.

(A) Following the first failure, the fuel nozzle(s) and burner tubes shall be replaced.

(B) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (i)(4)(iii)(A), the visible emissions test is not passed in the next scheduled test, either a performance test shall be performed under paragraph (e) of this section, or the device shall be replaced with another control device whose model was tested, and meets, the requirements in paragraph (h) of this section.

19. Section 63.773 is amended by:

a. Adding paragraph (b);

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);

d. Revising paragraphs (d)(2)(i) and (d)(2)(ii);

e. Revising paragraphs (d)(3)(i)(A) and (B);

f. Revising paragraphs (d)(3)(i)(D) and (E);

g. Revising paragraphs (d)(3)(i)(F)(*1*) and (*2*);

h. Revising paragraph (d)(3)(i)(G);

i. Adding paragraph (d)(3)(i)(H);

j. Revising paragraph (d)(4);

k. Revising paragraph (d)(5)(i);

l. Revising paragraphs (d)(5)(ii)(A) through (C);

m. Revising paragraphs (d)(6)(ii) and (iii);

n. Adding paragraph (d)(6)(vi);

o. Revising paragraph (d)(8)(i)(A); and

p. Revising paragraph (d)(8)(ii) to read as follows:

§ 63.773 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under § 63.772(h) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device, except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. Owners or operators that install and operate a flare in accordance with § 63.771(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.771(d), (e)(3) or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) * * *

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel; or

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.772(e) that the combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

* * * * *

(D) For a boiler or process heater a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.8 degrees C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) * * *

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. The mechanical connections for leakage must be checked at least every month, and a visual inspection must be performed at least every 3 months of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.772(e)(3) shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device model whose model is tested under § 63.772(h):

(*1*) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flow rate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.772(e)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.772(h) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flow rate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.772(e)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

* * * * *

(6) * * *

(ii) For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent of the identified 365-day required percent reduction.

(iii) For sources meeting § 63.771(d)(1)(ii), if an owner or operator has less than 365 days of data, an excursion occurs when the average condenser efficiency calculated according to the procedures specified in § 63.772(g)(2)(iii)(A) or (B) is less than 90.0 percent. For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than the identified 365-day required percent reduction.

* * * * *

(vi) For control device whose model is tested under § 63.772(h) an excursion occurs when:

(A) The inlet gas flow rate exceeds the maximum established during the test conducted under § 63.772(h).

(B) Failure of the monthly visible emissions test conducted under § 63.772(i)(3) occurs.

* * * * *

(8) * * *

(i) * * *

(A) During a malfunction when the affected facility is operated during such period in accordance with § 63.6(e)(1); or

* * * * *

(ii) For each control device, or combinations of control devices installed on the same emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.775(e) of this subpart.

* * * * *

20. Section 63.774 is amended by:

a. Revising paragraph (b)(3) introductory text;

b. Removing and reserving paragraph (b)(3)(ii);

c. Revising paragraph (b)(4)(ii) introductory text;

d. Adding paragraph (b)(4)(ii)(C);

e. Adding paragraph (b)(7)(ix); and

f. Adding paragraphs (g) through (i) to read as follows:

§ 63.774 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.773(d). Notwithstanding the requirements of § 63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (b)(3)(iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

* * * * *

(C) For control device whose model is tested under § 63.772(h), the records required in paragraph (h) of this section.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.771(d)(5) and records of each carbon replacement.

* * * * *

(g) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.764(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(h) Record the following when using a control device whose model is tested under § 63.772(h) to comply with § 63.771(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate measurements made during the compliance determination required by § 63.772(i); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(i) The date the semi-annual maintenance inspection required under § 63.773(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

21. Section 63.775 is amended by:

a. Revising paragraph (b)(1);

b. Revising paragraph (b)(6);

c. Removing and reserving paragraph (b)(7);

d. Revising paragraph (c)(1);

e. Revising paragraph (c)(6);

f. Revising paragraph (c)(7)(i);

g. Revising paragraph (d)(1)(i);

h. Revising paragraph (d)(1)(ii) introductory text;

i. Revising paragraph (d)(5)(ii);

j. Adding paragraph (d)(5)(iv);

k. Revising paragraph (d)(11);

l. Adding paragraphs (d)(13) and (d)(14);

m. Revising paragraphs (e)(2) introductory text, (e)(2)(ii)(B) and (C);

n. Adding paragraphs (e)(2)(ii)(E) and (F);

o. Adding paragraphs (e)(2)(xi) through (xiii); and

p. Adding paragraph (g) to read as follows:

§ 63.775 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (ii), the initial notifications shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.760(f)(7) or (9) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by one year after publication of the final rule in the **Federal Register**, whichever is later. An affected source identified under § 63.760(f)(7) or (9) that plans to be an area source by three years after publication of the final rule in the **Federal Register**, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) [Reserved]

* * * * *

(c) * * *

(1) The initial notifications required under § 63.9(b)(2) not later than January 3, 2008. In addition to submitting your initial notification to the addressees specified under § 63.9(a), you must also submit a copy of the initial notification to the EPA's Office of Air Quality Planning and Standards. Send your notification via e-mail to *Oil and Gas Sector@epa.gov* or via U.S. mail or other mail delivery service to U.S. EPA, Sector Policies and Programs Division/ Fuels and Incineration Group (E143–01), Attn: Oil and Gas Project Leader, Research Triangle Park, NC 27711.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and

a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) * * *

(i) Documentation of the source's location relative to the nearest UA plus offset and UC boundaries. This information shall include the latitude and longitude of the affected source; whether the source is located in an urban cluster with 10,000 people or more; the distance in miles to the nearest urbanized area boundary if the source is not located in an urban cluster with 10,000 people or more; and the name of the nearest urban cluster with 10,000 people or more and nearest urbanized area.

* * * * *

(d) * * *

(1) * * *

(i) The condenser design analysis documentation specified in § 63.772(e)(4) of this subpart, if the owner or operator elects to prepare a design analysis.

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.772(e)(3) and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.772(h), an electronic copy of the performance test results shall be submitted via e-mail to *Oil and Gas PT@EPA.GOV.*

* * * * *

(5) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.771(d)(5)(i).

* * * * *

(11) The owner or operator shall submit the analysis prepared under § 63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.765(b)(1)(iii), through process modifications or a combination of process modifications and one or more control devices.

* * * * *

(13) If the owner or operator installs a combustion control device model tested under the procedures in § 63.772(h), the data listed under § 63.772(h)(8).

(14) For each combustion control device model tested under § 63.772(h), the information listed in paragraphs (d)(14)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date of control device certification test.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xiii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 365-day average condenser control efficiency is less than the value specified in § 63.773(d)(6)(ii), the report must include the 365-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused when condenser control efficiency is less than the value specified in § 63.773(d)(6)(iii), the report must include the average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(E) For each excursion caused when the maximum inlet gas flow rate identified under § 63.772(h) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(F) For each excursion caused when visible emissions determined under § 63.772(i) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred.

* * * * *

(xi) The results of any periodic test as required in § 63.772(e)(3) conducted during the reporting period.

(xii) For each carbon adsorber used to meet the control device requirements of § 63.771(d)(1), records of each carbon replacement that occurred during the reporting period.

(xiii) For combustion control device inspections conducted in accordance with § 63.773(b) the records specified in § 63.774(i).

* * * * *

(g) *Electronic reporting.* (1) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into the EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

22. Appendix to subpart HH of part 63 is amended by revising Table 2 to read as follows:

Appendix to Subpart HH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7) through (a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	No	Section reserved.
§ 63.1(b)(3)	Yes.	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	Yes	Subpart HH exempts area sources from the requirement to obtain a Title V permit unless otherwise required by law as specified in § 63.760(h).
§ 63.1(c)(3) and (c)(4)	No	Section reserved.
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(2)	Yes.	
§ 63.4(a)(3) through (a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	Yes.	
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)(1)(i)	No	See § 63.764(j) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	No.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	Pending.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	Yes.	
§ 63.8(c)(4)(i)	No	Subpart HH does not require continuous opacity monitors.
§ 63.8(c)(4)(ii)	Yes.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluation, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	Yes.	
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification. Major and area sources that meet § 63.764(e) do not have to submit initial notifications.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(1)	Yes.	
§ 63.9(g)(2)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(3)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit notifications of compliance status.
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data onsite and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No	
§ 63.10(b)(2)(ii)	No	See § 63.774(g) for recordkeeping of occurrence, duration, and actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.10(b)(3)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (8)(c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (11)	No	See § 63.774(g) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes	Area sources located outside UA plus offset and UC boundaries do not have to submit performance test reports.
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.775(b)(6) or (c)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(2)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually. Area sources are required to submit Periodic Reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes.	
§ 63.16	Yes.	

Subpart HHH—[Amended]

23. Section 63.1270 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(4);

c. Revising paragraphs (d)(1) and (d)(2); and

d. Adding paragraphs (d)(3), (4) and (5) to read as follows:

§ 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in § 63.1271. Emissions for major source determination purposes can be estimated using the maximum natural gas throughput calculated in either paragraph (a)(1) or (2) of this section and paragraphs (a)(3) and (4) of this section. As an alternative to calculating the maximum natural gas throughput, the owner or operator of a new or existing source may use the facility design maximum natural gas throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels (without obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), and becomes a major source, must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (d) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(4) The owner or operator shall determine the maximum values for other parameters used to calculate potential emissions as the maximum over the same period for which maximum throughput is determined as specified in paragraph (a)(1) or (a)(2) of this section. These parameters shall be based on an annual average or the highest single measured value. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

* * * * *

(d) * * *

(1) Except as specified in paragraphs (d)(3) through (5) of this section, the owner or operator of an affected source, the construction or reconstruction of which commenced before February 6,

1998, shall achieve compliance with the provisions of this subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (d)(3) through (5) of this section, the owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(3) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction before August 23, 2011 must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(4) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction on or after August 23, 2011 must achieve compliance immediately upon initial startup or the date of publication of the final rule in the **Federal Register**, whichever is later.

(5) Each large glycol dehydration unit, as defined in § 63.1271, that has complied with the provisions of this subpart prior to August 23, 2011 by reducing its benzene emissions to less than 0.9 megagrams per year must achieve compliance no later than 90 days after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

* * * * *

24. Section 63.1271 is amended by:

a. Adding, in alphabetical order, new definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units,'' ''small glycol dehydration units''; and

b. Revising the definitions for ''glycol dehydration unit baseline operations'' and ''temperature monitoring device'' to read as follows:

§ 63.1271 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydration unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, glycol dehydration unit baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 283.0 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.1282(a).

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 283.0 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.1282(a).

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in °C, or ± 2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

* * * * *

25. Section 63.1272 is revised to read as follows:

§ 63.1272 Startups and shutdowns.

(a) The provisions set forth in this subpart shall apply at all times.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup or shutdown of the affected source or a portion thereof.

(c) During startups and shutdowns, the owner or operator shall implement measures to prevent or minimize excess emissions to the maximum extent practical.

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, the owner or operator must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

26. Section 63.1274 is amended by:

a. Revising paragraph (c) introductory text;

b. Removing and reserving paragraph (d);

c. Revising paragraph (g); and

d. Adding paragraph (h) to read as follows:

§ 63.1274 General standards.

* * * * *

(c) The owner or operator of an affected source (*i.e.,* glycol dehydration unit) located at an existing or new major source of HAP emissions shall comply with the requirements in this subpart as follows:

* * * * *

(d) [Reserved]

* * * * *

(g) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(h) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

27. Section 63.1275 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b)(1);

c. Revising paragraph (c)(2); and

d. Revising paragraph (c)(3) to read as follows:

§ 63.1275 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in paragraph (c)(1) of § 63.1274.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (b)(1)(iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.1271, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d).

(ii) [Reserved]

(iii) You must limit BTEX emissions from each small glycol dehydration unit, as defined in § 63.1271, to the limit determined in Equation 1 of this section. The limit must be met in accordance with one of the alternatives specified in paragraphs (b)(i)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 6.42x10^{-5} * Throughput * C_{i,BTEX} * 365\,\frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \qquad \text{Equation 1}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;
6.42×10^{-5} = BTEX emission limit, grams BTEX/standard cubic meter -ppmv;
Throughput = Annual average daily natural gas throughput, standard cubic meters per day
$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.1281(e).

(C) Meet the emission limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.1281(e) and emissions in accordance with the requirements specified in § 63.1282(a)(3).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.1281(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) or (iii) through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) [Reserved]

(iii) For each small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in paragraph (b)(1)(iii) of this section.

28. Section 63.1281 is amended by:

a. Revising paragraph (c)(1);

b. Revising the heading of paragraph (d).

c. Adding paragraph (d) introductory text;

d. Revising paragraph (d)(1)(i) introductory text;

e. Revising paragraph (d)(1)(i)(C);

f. Revising paragraphs (d)(1)(ii) and (iii);

g. Revising paragraph (d)(4)(i);

h. Revising paragraph (d)(5)(i);

i. Revising paragraph (e)(2);

j. Revising paragraph (e)(3) introductory text;

k. Revising paragraph (e)(3)(ii); and

l. Adding paragraph (f) to read as follows:

§ 63.1281 Control equipment requirements.

* * * * *

(c) * * *

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units shall comply with the control requirements in paragraph (f) of this section.

(1) * * *

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

* * * * *

(C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 63.1282(d), operates at a minimum temperature of 760 °C.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the emissions unit or units through the closed vent system to the control device as required under § 63.1275. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.1284(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.1285(d)(4)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.1285(e)(2)(xi).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.1275(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit

determined in § 63.1275(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.1275(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d). If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d); or

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.1283(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.1282(e) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

29. Section 63.1282 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(1)(ii);

c. Revising paragraph (a)(2);

d. Adding paragraph (c);

e. Revising paragraph (d) introductory text;

f. Revising paragraphs (d)(1)(i) through (v);

g. Revising paragraph (d)(2);

h. Revising paragraph (d)(3) introductory text;

i. Revising paragraph (d)(3)(i)(B);

j. Revising paragraph (d)(3)(iv)(C)(*1*);

k. Adding paragraphs (d)(3)(v) and (vi);

l. Revising paragraph (d)(4) introductory text;

m. Revising paragraph (d)(4)(i);

n. Revising paragraph (d)(5);

o. Revising paragraph (e) introductory text;

p. Revising paragraphs (e)(2) and (e)(3);

q. Adding paragraphs (e)(4) through (e)(6);

r. Revising paragraph (f) introductory text;

s. Revising paragraph (f)(1);

t. Revising paragraph (f)(2) introductory text;

u. Revising paragraph (f)(2)(iii);

v. Revising paragraph (f)(3); and

w. Adding paragraphs (g) and (h) to read as follows:

§ 63.1282 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (a)(2)(ii) of this section. Emissions shall be determined either uncontrolled or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

* * * * *

(c) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.1275(b)(1)(iii), the requirements of paragraph (d) of this section apply. Compliance is demonstrated using the methods specified in paragraph (e) of this section.

(2) If no control device is used to comply with the emission limit in § 63.1275(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (c)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (c)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.1275(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (d)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(d) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) using a performance test as specified in paragraph (d)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (d)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (d)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (g) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (d)(2) of this section, a flare, as defined in § 63.1271, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.1271, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) the owner or operator shall use the test methods and procedures specified in paragraphs (d)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (d)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), or the BTEX emission limit specified in § 63.1275(b)(1)(iii), the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration ($\%O_{2d}$). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.1281(f)(1) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (d)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (d)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (d)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.1270(d)(3) and (4) except that the initial performance test for existing combustion control devices at existing major sources shall be conducted no later than 3 years after the date of publication of the final rule in the **Federal Register**. If the owner or operator of an existing combustion control device at an existing major source chooses to replace such device with a control device whose model is tested under § 63.1282(g), then the newly installed device shall comply with all provisions of this subpart no later than 3 years after the date of publication of the final rule in the **Federal Register**. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.1285(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (d)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.1285(e)(2)(x). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.1282(g), or

(*2*) A combustion control device tested under § 63.1282(d) that meets the outlet TOC or HAP performance level specified in § 63.1281(d)(1)(i)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC or HAP performance level.

* * * * *

(4) For a condenser design analysis conducted to meet the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (d)(4)(i) and (d)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.1285(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (d)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (d)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ‘‘Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions,’’ (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(e) *Compliance demonstration for control devices performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (e)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.1281(d)(1)(ii), (e)(3)(ii), or (f)(1) may demonstrate compliance according to paragraph (f) of this section. An owner or operator may switch between compliance with paragraph (e) of this section and compliance with paragraph (f) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.1285(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.1283(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (e)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.1282(g).

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.1283(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(f) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.1281(d)(1)(ii), (e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (f)(1) through (f)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to the procedures specified in § 63.1283(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.1281(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the percent reduction requirement in § 63.1281(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (f)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (f)(2)(iii)(A), (B), and (D) of this section, at the end of each operating day the owner or operator shall calculate the 30-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(2)(ii) of this section for the preceding 30 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.1281(e), the 30-day average HAP emission, or BTEX, emission reduction, shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (f)(2)(ii) of this section, both for the preceding 30 operating days.

(A) After the compliance date specified in § 63.1270(d), an owner or operator of a facility that stores natural gas that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the withdrawal season, each season, until 30 days of condenser operating data are accumulated. For a facility that does not store natural gas, the owner or operator that has less than 30 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the calendar year, each year, until 30 days of condenser operating data are accumulated.

(B) After the compliance date specified in § 63.1270(d), for an owner or operator that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, compliance is achieved if the average HAP, or BTEX, emission reduction, as appropriate, calculated in paragraph (f)(2)(iii)(A) of this section is equal to or greater than 95.0 percent.

* * * * *

(3) Compliance is achieved based on the applicable criteria in paragraphs (f)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.1281(d)(1)(ii) or (e)(3) if the average HAP emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.1281(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (f)(1) of this section.

* * * * *

(g) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (g)(7) of this section by conducting a performance test as specified in paragraphs (g)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (g)(8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (g)(4)(i) through (iii) of this section.

(i) The fuel flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) Inlet flow rate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet fuel sampling shall be conducted in accordance with the criteria in paragraphs (g)(4)(iii)(A) and (B) of this section.

(A) At the inlet fuel sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of the THC test.

(*2*) Fill one canister for each THC test run.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each fuel sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(*3*) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504.

(*4*) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (g)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flow rate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (g)(4)(iii)(B), and (g)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be kneaded or otherwise vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iv) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A. The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(v) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (g)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (g)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (g)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (g)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(ii) The manufacturer shall determine a maximum inlet gas flow rate which shall not be exceeded for each control device model to achieve the criteria in paragraph (g)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraph (g)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 98.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (g)(8)(i) through (iii) in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (g)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(h) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (g) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (g) of this section and complying with the following criteria:

(1) The inlet gas flow rate shall meet the range specified by the manufacturer. Flow rate shall be measured as specified in § 63.1283(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.1283(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed monthly. The observation period shall be 2 hours and shall be used according to Method 22.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flow rate monitored under paragraph (h)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (h)(3) of this section the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test shall follow the requirements in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) Following the first failure, the fuel nozzle(s) and burner tubes shall be replaced.

(B) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (h)(4)(iii)(A), the visible emissions test is not passed in the next scheduled test, either a performance test shall be performed under paragraph (d) of this section, or the device shall be replaced with another control device whose model was tested, and meets, the requirements in paragraph (g) of this section.

30. Section 63.1283 is amended by:

a. Adding paragraph (b);

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);

d. Revising paragraph (d)(2)(i) and (d)(2)(ii);

e. Revising paragraphs (d)(3)(i)(A) and (B);

f. Revising paragraphs (d)(3)(i)(D) and (E);

g. Revising paragraphs (d)(3)(i)(F)(*1*) and (*2*);

h. Revising paragraph (d)(3)(i)(G);

i. Adding paragraph (d)(3)(i)(H);

j. Revising paragraph (d)(4);

k. Revising paragraph (d)(5)(i);

l. Revising paragraphs (d)(5)(ii)(A) through (C);

m. Revising paragraph (d)(6) introductory text;

n. Revising paragraph (d)(6)(ii);

o. Adding paragraph (d)(6)(v);

p. Revising paragraph (d)(8)(i)(A); and

q. Revising paragraph (d)(8)(ii) to read as follows:

§ 63.1283 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under 63.1282(g) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. Owners or operators that install and operate a flare in accordance with § 63.1281(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.1281(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) * * *

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel;

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.1282(d) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperatures at two locations and have a minimum accuracy of ± 1 percent of the temperatures being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.8 degrees C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) * * *

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. The mechanical connections for leakage must be checked at least every month, and a visual inspection must be performed at least every 3 months of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.1282(d)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device whose model is tested under § 63.1282(g):

(*1*) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer's recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.1282(d)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.1282(g) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flow rate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day, and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(iv) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.1281(d)(1)(ii), an excursion occurs when average condenser efficiency calculated according to the requirements specified in § 63.1282(f)(2)(iii) is less than 95.0 percent, as specified in § 63.1282(f)(3). For sources meeting § 63.1281(f)(1), an excursion occurs when the 30-day average condenser efficiency calculated according to the requirements of § 63.1282(f)(2)(iii) is less than the identified 30-day required percent reduction.

* * * * *

(v) For control device whose model is tested under § 63.1282(g) an excursion occurs when:

(A) The inlet gas flow rate exceeds the maximum established during the test conducted under § 63.1282(g).

(B) Failure of the monthly visible emissions test conducted under § 63.1282(h)(3) occurs.

(8) * * *

(i) * * *

(A) During a malfunction when the affected facility is operated during such period in accordance with § 63.6(e)(1); or

* * * * *

(ii) For each control device, or combinations of control devices, installed on the same emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.1285(e) of this subpart.

* * * * *

31. Section 63.1284 is amended by:

a. Revising paragraph (b)(3) introductory text;

b. Removing and reserving paragraph (b)(3)(ii);

c. Revising paragraph (b)(4)(ii);

d. Adding paragraph (b)(7)(ix); and

e. Adding paragraph (f), (g) and (h) to read as follows:

§ 63.1284 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d). Notwithstanding the previous sentence, monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.1283(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

(A) For flares, the records required in paragraph (e) of this section.

(B) For condensers installed to comply with § 63.1275, records of the annual 30-day rolling average condenser efficiency determined under § 63.1282(f) shall be kept in addition to the daily averages.

(C) For a control device whose model is tested under § 63.1282(g), the records required in paragraph (g) of this section.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.1281(d)(5) and records of each carbon replacement.

* * * * *

(f) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.1274(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(g) Record the following when using a control device whose model is tested under § 63.1282(g) to comply with § 63.1281(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate measurements made during the compliance determination required by § 63.1282(h); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(h) The date the semi-annual maintenance inspection required under § 63.1283(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

32. Section 63.1285 is amended by:

a. Revising paragraph (b)(1);

b. Revising paragraph (b)(6);

c. Removing paragraph (b)(7);

d. Revising paragraph (d)(1) introductory text;

e. Revising paragraph (d)(1)(i);

f. Revising paragraph (d)(1)(ii) introductory text;

g. Revising paragraph (d)(2) introductory text;

h. Revising paragraph (d)(4)(ii);

i. Adding paragraph (d)(4)(iv);

j. Revising paragraph (d)(10);

k. Adding paragraphs (d)(11) and (d)(12);

l. Revising paragraph (e)(2) introductory text;

m. Revising paragraph (e)(2)(ii)(B);

n. Adding paragraphs (e)(2)(ii)(D) and (E);

o. Adding paragraphs (e)(2)(x), (xi) and (xii); and

p. Adding paragraph (g) to read as follows:

§ 63.1285 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notification shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.1270(d)(3) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by one year after publication of the final rule in the **Federal Register**, whichever is later. An affected source identified under § 63.1270(d)(3) that plans to be an area source by three years after publication of the final rule in the **Federal Register**, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of

actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1274(h), including actions taken to correct a malfunction.

* * * * *

(d) * * *

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.1274, the owner or operator shall submit the information in paragraph (d)(1)(iii) of this section and the information in either paragraph (d)(1)(i) or (ii) of this section.

(i) The condenser design analysis documentation specified in § 63.1282(d)(4) of this subpart if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.1282(d)(3), and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.1282(g), an electronic copy of the performance test results shall be submitted via e-mail to *Oil_and_Gas_PT@EPA.GOV.*

* * * * *

(2) If a closed-vent system and a flare are used to comply with § 63.1274, the owner or operator shall submit performance test results including the information in paragraphs (d)(2)(i) and (ii) of this section. The owner or operator shall also submit the information in paragraph (d)(2)(iii) of this section.

* * * * *

(4) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1283(d)(5) of this subpart. This explanation shall include any data and calculations used to develop the value, and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.1281(d)(5)(i).

* * * * *

(10) The owner or operator shall submit the analysis prepared under § 63.1281(e)(2) to demonstrate that the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.1275(b)(1)(iii) through process modifications or a combination of process modifications and one or more control devices.

(11) If the owner or operator installs a combustion control device model tested under the procedures in § 63.1282(g), the data listed under § 63.1282(g)(8).

(12) For each combustion control device model tested under § 63.1282(g), the information listed in paragraphs (d)(12)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date of control device certification test.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

* * * * *

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 30-day average condenser control efficiency is less than the value, as specified in § 63.1283(d)(6)(ii), the report must include the 30-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(D) For each excursion caused when the maximum inlet gas flow rate identified under § 63.1282(g) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(E) For each excursion caused when visible emissions determined under § 63.1282(h) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred.

* * * * *

(x) The results of any periodic test as required in § 63.1282(d)(3) conducted during the reporting period.

(xi) For each carbon adsorber used to meet the control device requirements of § 63.1281(d)(1), records of each carbon replacement that occurred during the reporting period.

(xii) For combustion control device inspections conducted in accordance with § 63.1283(b) the records specified in § 63.1284(h).

* * * * *

(g) *Electronic reporting.* (1) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/).* Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into the EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

33. Section 63.1287 is amended by revising paragraph (a) to read as follows:

§ 63.1287 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.1274 through 63.1281, the Administrator will publish a notice in the **Federal Register** permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

* * * * *

34. Appendix to Subpart HHH of Part 63—Table is amended by revising Table 2 to read as follows:

Appendix to Subpart HHH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes.	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12) through (a)(14)	Yes.	
§ 63.1(b)(1)	No	Subpart HHH specifies applicability.
§ 63.1(b)(2)	Yes.	
§ 63.1(b)(3)	No.	
§ 63.1(c)(1)	No	Subpart HHH specifies applicability.
§ 63.1(c)(2)	No.	
§ 63.1(c)(3)	No	Section reserved.
§ 63.1(c)(4)	Yes.	
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HHH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(3)	Yes.	
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	Yes.	
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	Yes.	
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) and (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)	Yes	Except as otherwise specified.
§ 63.6(e)(1)(i)	No	See § 63.1274(h) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	Yes.	
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HHH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	Yes.	
63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	Pending.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	No.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HHH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	No	Subpart HHH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HHH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	Yes.	
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes.	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) and (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	Section 63.1284(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.1284(f) for recordkeeping of occurrence, duration, and actions taken during malfunction.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	
§ 63.10(b)(3)	No.	
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.10(c)(10) and (c)(11)	No	See § 63.1284(f)for recordkeeping of malfunctions
§ 63.10(c)(12) through (c)(14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes.	
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.1285(b)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes.	
§ 63.10(e)(2)	Yes.	
§ 63.10(e)(3)(i)	Yes	Subpart HHH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Subpart HHH does not require quarterly reporting for excess emissions.
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes.	

[FR Doc. 2011–19899 Filed 8–22–11; 8:45 am]

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Historical Overview of Climate Change Science

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Frequently Asked Questions

Executive Summary

Awareness and a partial understanding of most of the interactive processes in the Earth system that govern climate and climate change predate the IPCC, often by many decades. A deeper understanding and quantification of these processes and their incorporation in climate models have progressed rapidly since the IPCC First Assessment Report in 1990.

As climate science and the Earth's climate have continued to evolve over recent decades, increasing evidence of anthropogenic influences on climate change has been found. Correspondingly, the IPCC has made increasingly more definitive statements about human impacts on climate.

Debate has stimulated a wide variety of climate change research. The results of this research have refined but not significantly redirected the main scientific conclusions from the sequence of IPCC assessments.

1.1 Overview of the Chapter

To better understand the science assessed in this Fourth Assessment Report (AR4), it is helpful to review the long historical perspective that has led to the current state of climate change knowledge. This chapter starts by describing the fundamental nature of earth science. It then describes the history of climate change science using a wide-ranging subset of examples, and ends with a history of the IPCC.

The concept of this chapter is new. There is no counterpart in previous IPCC assessment reports for an introductory chapter providing historical context for the remainder of the report. Here, a restricted set of topics has been selected to illustrate key accomplishments and challenges in climate change science. The topics have been chosen for their significance to the IPCC task of assessing information relevant for understanding the risks of human-induced climate change, and also to illustrate the complex and uneven pace of scientific progress.

In this chapter, the time frame under consideration stops with the publication of the Third Assessment Report (TAR; IPCC, 2001a). Developments subsequent to the TAR are described in the other chapters of this report, and we refer to these chapters throughout this first chapter.

1.2 The Nature of Earth Science

Science may be stimulated by argument and debate, but it generally advances through formulating hypotheses clearly and testing them objectively. This testing is the key to science. In fact, one philosopher of science insisted that to be genuinely scientific, a statement must be susceptible to testing that could potentially show it to be false (Popper, 1934). In practice, contemporary scientists usually submit their research findings to the scrutiny of their peers, which includes disclosing the methods that they use, so their results can be checked through replication by other scientists. The insights and research results of individual scientists, even scientists of unquestioned genius, are thus confirmed or rejected in the peer-reviewed literature by the combined efforts of many other scientists. It is not the belief or opinion of the scientists that is important, but rather the results of this testing. Indeed, when Albert Einstein was informed of the publication of a book entitled *100 Authors Against Einstein*, he is said to have remarked, 'If I were wrong, then one would have been enough!' (Hawking, 1988); however, that one opposing scientist would have needed proof in the form of testable results.

Thus science is inherently self-correcting; incorrect or incomplete scientific concepts ultimately do not survive repeated testing against observations of nature. Scientific theories are ways of explaining phenomena and providing insights that can be evaluated by comparison with physical reality. Each successful prediction adds to the weight of evidence supporting the theory, and any unsuccessful prediction demonstrates that the underlying theory is imperfect and requires improvement or abandonment. Sometimes, only certain kinds of questions tend to be asked about a scientific phenomenon until contradictions build to a point where a sudden change of paradigm takes place (Kuhn, 1996). At that point, an entire field can be rapidly reconstructed under the new paradigm.

Despite occasional major paradigm shifts, the majority of scientific insights, even unexpected insights, tend to emerge incrementally as a result of repeated attempts to test hypotheses as thoroughly as possible. Therefore, because almost every new advance is based on the research and understanding that has gone before, science is cumulative, with useful features retained and non-useful features abandoned. Active research scientists, throughout their careers, typically spend large fractions of their working time studying in depth what other scientists have done. Superficial or amateurish acquaintance with the current state of a scientific research topic is an obstacle to a scientist's progress. Working scientists know that a day in the library can save a year in the laboratory. Even Sir Isaac Newton (1675) wrote that if he had 'seen further it is by standing on the shoulders of giants'. Intellectual honesty and professional ethics call for scientists to acknowledge the work of predecessors and colleagues.

The attributes of science briefly described here can be used in assessing competing assertions about climate change. Can the statement under consideration, in principle, be proven false? Has it been rigorously tested? Did it appear in the peer-reviewed literature? Did it build on the existing research record where appropriate? If the answer to any of these questions is no, then less credence should be given to the assertion until it is tested and independently verified. The IPCC assesses the scientific literature to create a report based on the best available science (Section 1.6). It must be acknowledged, however, that the IPCC also contributes to science by identifying the key uncertainties and by stimulating and coordinating targeted research to answer important climate change questions.

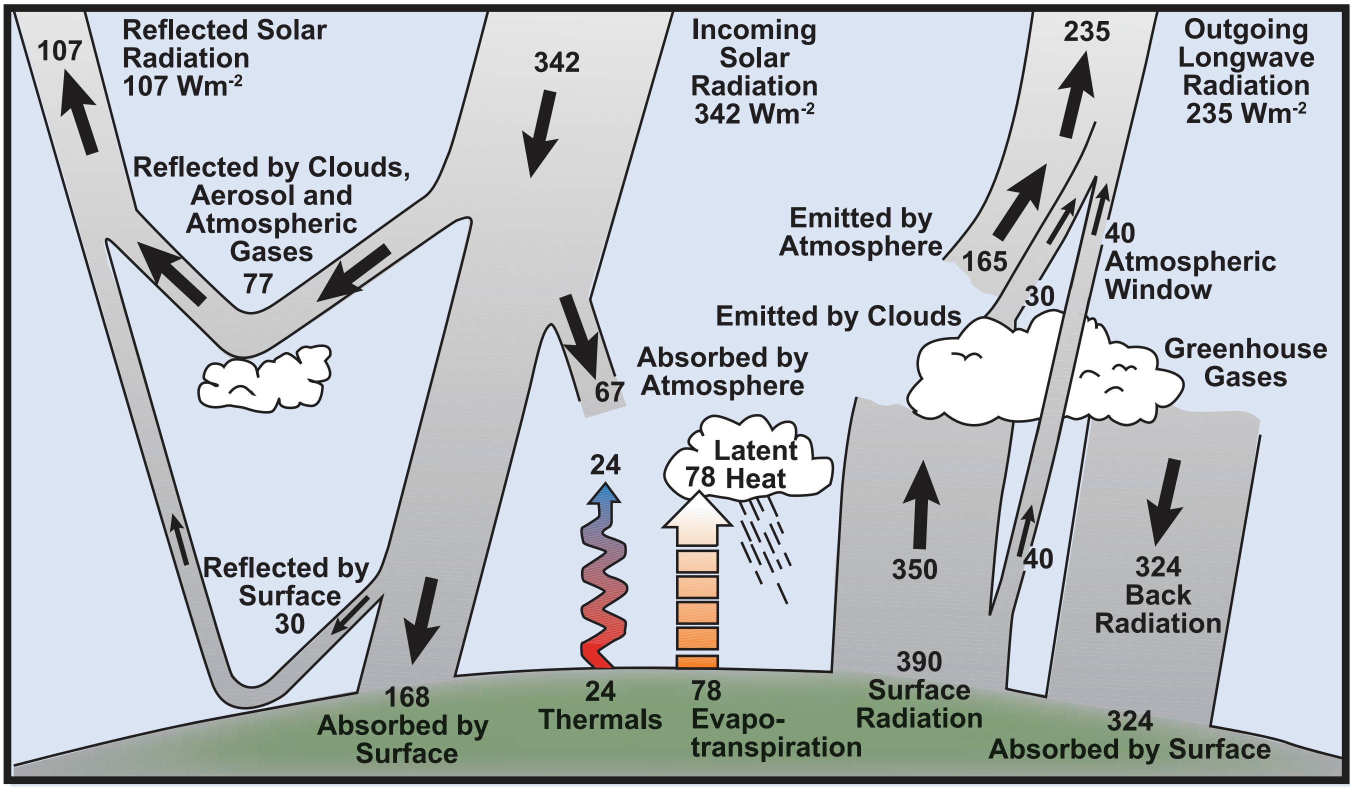
Frequently Asked Question 1.1

What Factors Determine Earth's Climate?

The climate system is a complex, interactive system consisting of the atmosphere, land surface, snow and ice, oceans and other bodies of water, and living things. The atmospheric component of the climate system most obviously characterises climate; climate is often defined as 'average weather'. Climate is usually described in terms of the mean and variability of temperature, precipitation and wind over a period of time, ranging from months to millions of years (the classical period is 30 years). The climate system evolves in time under the influence of its own internal dynamics and due to changes in external factors that affect climate (called 'forcings'). External forcings include natural phenomena such as volcanic eruptions and solar variations, as well as human-induced changes in atmospheric composition. Solar radiation powers the climate system. There are three fundamental ways to change the radiation balance of the Earth: 1) by changing the incoming solar radiation (e.g., by changes in Earth's orbit or in the Sun itself); 2) by changing the fraction of solar radiation that is reflected (called 'albedo'; e.g., by changes in cloud cover, atmospheric particles or vegetation); and 3) by altering the longwave radiation from Earth back towards space (e.g., by changing greenhouse gas concentrations). Climate, in turn, responds directly to such changes, as well as indirectly, through a variety of feedback mechanisms.

The amount of energy reaching the top of Earth's atmosphere each second on a surface area of one square metre facing the Sun during daytime is about 1,370 Watts, and the amount of energy per square metre per second averaged over the entire planet is one-quarter of this (see Figure 1). About 30% of the sunlight that reaches the top of the atmosphere is reflected back to space. Roughly two-thirds of this reflectivity is due to clouds and small particles in the atmosphere known as 'aerosols'. Light-coloured areas of Earth's surface – mainly snow, ice and deserts – reflect the remaining one-third of the sunlight. The most dramatic change in aerosol-produced reflectivity comes when major volcanic eruptions eject material very high into the atmosphere. Rain typically

(continued)



FAQ 1.1, Figure 1. *Estimate of the Earth's annual and global mean energy balance. Over the long term, the amount of incoming solar radiation absorbed by the Earth and atmosphere is balanced by the Earth and atmosphere releasing the same amount of outgoing longwave radiation. About half of the incoming solar radiation is absorbed by the Earth's surface. This energy is transferred to the atmosphere by warming the air in contact with the surface (thermals), by evapotranspiration and by longwave radiation that is absorbed by clouds and greenhouse gases. The atmosphere in turn radiates longwave energy back to Earth as well as out to space. Source: Kiehl and Trenberth (1997).*

clears aerosols out of the atmosphere in a week or two, but when material from a violent volcanic eruption is projected far above the highest cloud, these aerosols typically influence the climate for about a year or two before falling into the troposphere and being carried to the surface by precipitation. Major volcanic eruptions can thus cause a drop in mean global surface temperature of about half a degree celsius that can last for months or even years. Some man-made aerosols also significantly reflect sunlight.

The energy that is not reflected back to space is absorbed by the Earth's surface and atmosphere. This amount is approximately 240 Watts per square metre (W m^{-2}). To balance the incoming energy, the Earth itself must radiate, on average, the same amount of energy back to space. The Earth does this by emitting outgoing longwave radiation. Everything on Earth emits longwave radiation continuously. That is the heat energy one feels radiating out from a fire; the warmer an object, the more heat energy it radiates. To emit 240 W m^{-2}, a surface would have to have a temperature of around –19°C. This is much colder than the conditions that actually exist at the Earth's surface (the global mean surface temperature is about 14°C). Instead, the necessary –19°C is found at an altitude about 5 km above the surface.

The reason the Earth's surface is this warm is the presence of greenhouse gases, which act as a partial blanket for the longwave radiation coming from the surface. This blanketing is known as the natural greenhouse effect. The most important greenhouse gases are water vapour and carbon dioxide. The two most abundant constituents of the atmosphere – nitrogen and oxygen – have no such effect. Clouds, on the other hand, do exert a blanketing effect similar to that of the greenhouse gases; however, this effect is offset by their reflectivity, such that on average, clouds tend to have a cooling effect on climate (although locally one can feel the warming effect: cloudy nights tend to remain warmer than clear nights because the clouds radiate longwave energy back down to the surface). Human activities intensify the blanketing effect through the release of greenhouse gases. For instance, the amount of carbon dioxide in the atmosphere has increased by about 35% in the industrial era, and this increase is known to be due to human activities, primarily the combustion of fossil fuels and removal of forests. Thus, humankind has dramatically altered the chemical composition of the global atmosphere with substantial implications for climate.

Because the Earth is a sphere, more solar energy arrives for a given surface area in the tropics than at higher latitudes, where sunlight strikes the atmosphere at a lower angle. Energy is transported from the equatorial areas to higher latitudes via atmospheric and oceanic circulations, including storm systems. Energy is also required to evaporate water from the sea or land surface, and this energy, called latent heat, is released when water vapour condenses in clouds (see Figure 1). Atmospheric circulation is primarily driven by the release of this latent heat. Atmospheric circulation in turn drives much of the ocean circulation through the action of winds on the surface waters of the ocean, and through changes in the ocean's surface temperature and salinity through precipitation and evaporation.

Due to the rotation of the Earth, the atmospheric circulation patterns tend to be more east-west than north-south. Embedded in the mid-latitude westerly winds are large-scale weather systems that act to transport heat toward the poles. These weather systems are the familiar migrating low- and high-pressure systems and their associated cold and warm fronts. Because of land-ocean temperature contrasts and obstacles such as mountain ranges and ice sheets, the circulation system's planetary-scale atmospheric waves tend to be geographically anchored by continents and mountains although their amplitude can change with time. Because of the wave patterns, a particularly cold winter over North America may be associated with a particularly warm winter elsewhere in the hemisphere. Changes in various aspects of the climate system, such as the size of ice sheets, the type and distribution of vegetation or the temperature of the atmosphere or ocean will influence the large-scale circulation features of the atmosphere and oceans.

There are many feedback mechanisms in the climate system that can either amplify ('positive feedback') or diminish ('negative feedback') the effects of a change in climate forcing. For example, as rising concentrations of greenhouse gases warm Earth's climate, snow and ice begin to melt. This melting reveals darker land and water surfaces that were beneath the snow and ice, and these darker surfaces absorb more of the Sun's heat, causing more warming, which causes more melting, and so on, in a self-reinforcing cycle. This feedback loop, known as the 'ice-albedo feedback', amplifies the initial warming caused by rising levels of greenhouse gases. Detecting, understanding and accurately quantifying climate feedbacks have been the focus of a great deal of research by scientists unravelling the complexities of Earth's climate.

A characteristic of Earth sciences is that Earth scientists are unable to perform controlled experiments on the planet as a whole and then observe the results. In this sense, Earth science is similar to the disciplines of astronomy and cosmology that cannot conduct experiments on galaxies or the cosmos. This is an important consideration, because it is precisely such whole-Earth, system-scale experiments, incorporating the full complexity of interacting processes and feedbacks, that might ideally be required to fully verify or falsify climate change hypotheses (Schellnhuber et al., 2004). Nevertheless, countless empirical tests of numerous different hypotheses have built up a massive body of Earth science knowledge. This repeated testing has refined the understanding of numerous aspects of the climate system, from deep oceanic circulation to stratospheric chemistry. Sometimes a combination of observations and models can be used to test planetary-scale hypotheses. For example, the global cooling and drying of the atmosphere observed after the eruption of Mt. Pinatubo (Section 8.6) provided key tests of particular aspects of global climate models (Hansen et al., 1992).

Another example is provided by past IPCC projections of future climate change compared to current observations. Figure 1.1 reveals that the model projections of global average temperature from the First Assessment Report (FAR; IPCC, 1990) were higher than those from the Second Assessment Report (SAR; IPCC, 1996). Subsequent observations (Section 3.2) showed that the evolution of the actual climate system fell midway between the FAR and the SAR 'best estimate' projections and were within or near the upper range of projections from the TAR (IPCC, 2001a).

Not all theories or early results are verified by later analysis. In the mid-1970s, several articles about possible global cooling appeared in the popular press, primarily motivated by analyses indicating that Northern Hemisphere (NH) temperatures had decreased during the previous three decades (e.g., Gwynne, 1975). In the peer-reviewed literature, a paper by Bryson and Dittberner (1976) reported that increases in carbon dioxide (CO_2) should be associated with a decrease in global temperatures. When challenged by Woronko (1977), Bryson and Dittberner (1977) explained that the cooling projected by their model was due to aerosols (small particles in the atmosphere) produced by the same combustion that caused the increase in CO_2. However, because aerosols remain in the atmosphere only a short time compared to CO_2, the results were not applicable for long-term climate change projections. This example of a prediction of global cooling is a classic illustration of the self-correcting nature of Earth science. The scientists involved were reputable researchers who followed the accepted paradigm of publishing in scientific journals, submitting their methods and results to the scrutiny of their peers (although the peer-review did not catch this problem), and responding to legitimate criticism.

A recurring theme throughout this chapter is that climate science in recent decades has been characterised by the increasing rate of advancement of research in the field and by the notable evolution of scientific methodology and tools, including the models and observations that support and enable the research. During the last four decades, the rate at which scientists have added to the body of knowledge of atmospheric and oceanic processes has accelerated dramatically. As scientists incrementally increase the totality of knowledge, they publish their results in peer-reviewed journals. Between 1965 and 1995, the number of articles published per year in atmospheric science journals tripled (Geerts, 1999). Focusing more narrowly, Stanhill (2001) found that the climate change science literature grew approximately exponentially with a doubling time of 11 years for the period 1951 to 1997. Furthermore, 95% of all the climate change science literature since 1834 was published after 1951. Because science is cumulative, this represents considerable growth in the knowledge of climate processes and in the complexity of climate research. An important example of this is the additional physics incorporated in climate models over the last several decades, as illustrated in Figure 1.2. As a result of the cumulative nature of science, climate science today is an interdisciplinary synthesis of countless tested and proven physical processes and principles painstakingly compiled and verified over several centuries of detailed laboratory measurements, observational experiments and theoretical analyses; and is now far more wide-ranging and physically comprehensive than was the case only a few decades ago.

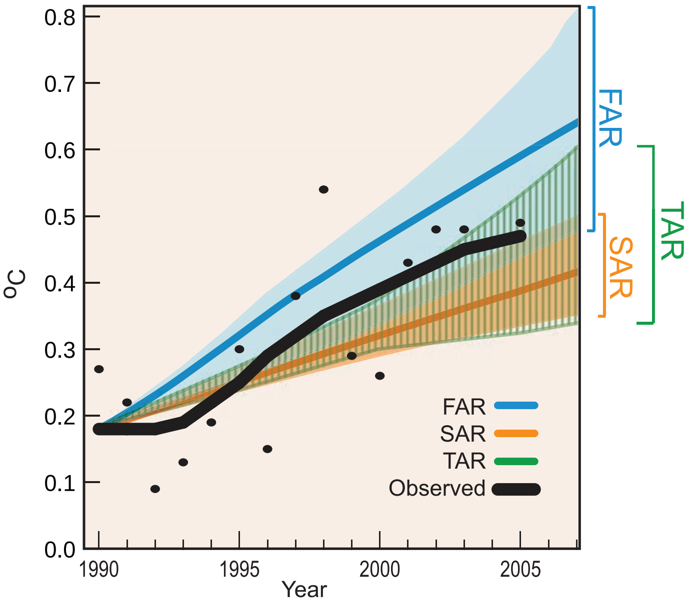


Figure 1.1. *Yearly global average surface temperature (Brohan et al., 2006), relative to the mean 1961 to 1990 values, and as projected in the FAR (IPCC, 1990), SAR (IPCC, 1996) and TAR (IPCC, 2001a). The 'best estimate' model projections from the FAR and SAR are in solid lines with their range of estimated projections shown by the shaded areas. The TAR did not have 'best estimate' model projections but rather a range of projections. Annual mean observations (Section 3.2) are depicted by black circles and the thick black line shows decadal variations obtained by smoothing the time series using a 13-point filter.*

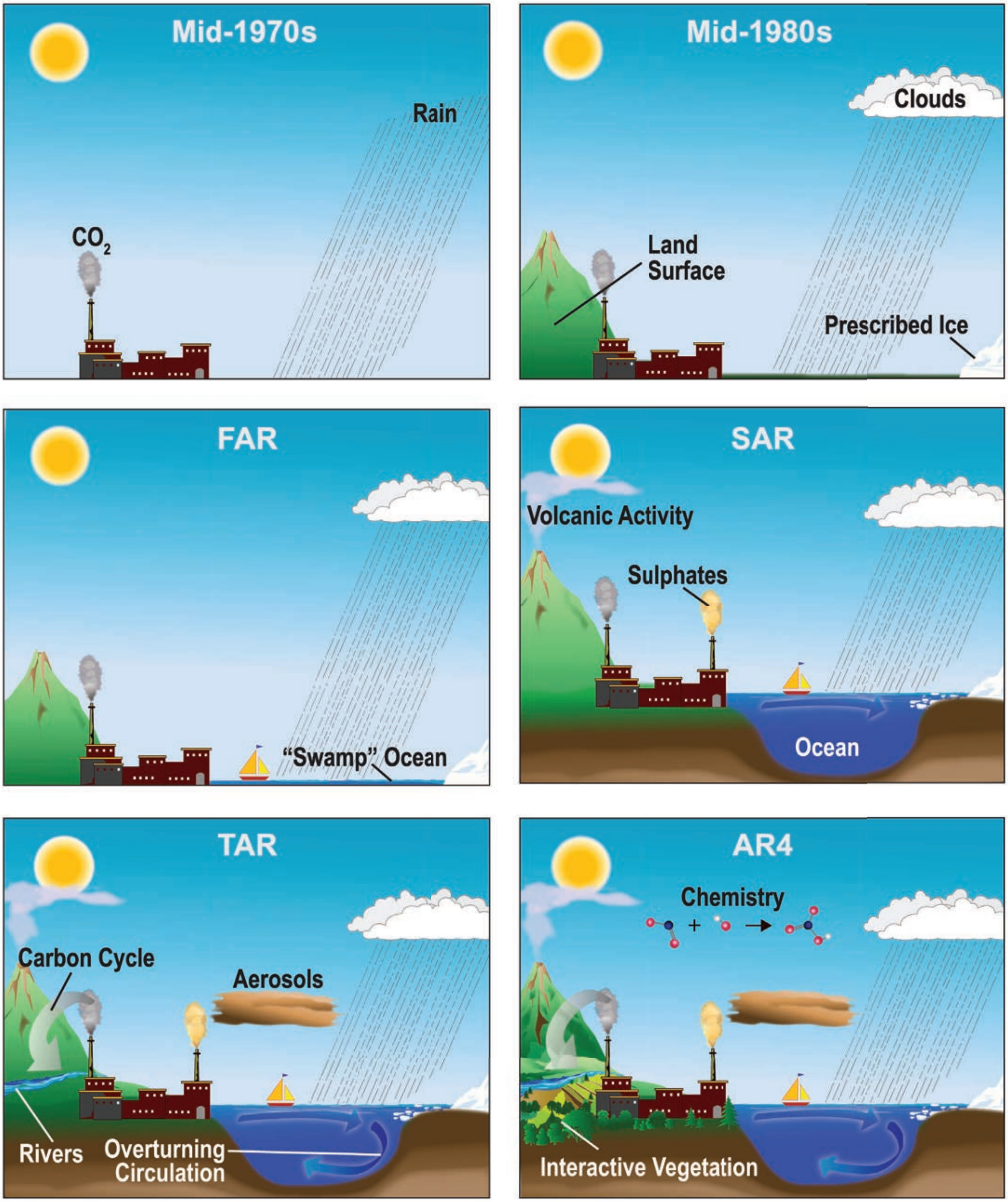


Figure 1.2. *The complexity of climate models has increased over the last few decades. The additional physics incorporated in the models are shown pictorially by the different features of the modelled world.*

1.3 Examples of Progress in Detecting and Attributing Recent Climate Change

1.3.1 The Human Fingerprint on Greenhouse Gases

The high-accuracy measurements of atmospheric CO_2 concentration, initiated by Charles David Keeling in 1958, constitute the master time series documenting the changing composition of the atmosphere (Keeling, 1961, 1998). These data have iconic status in climate change science as evidence of the effect of human activities on the chemical composition of the global atmosphere (see FAQ 7.1). Keeling's measurements on Mauna Loa in Hawaii provide a true measure of the global carbon cycle, an effectively continuous record of the burning of fossil fuel. They also maintain an accuracy and precision that allow scientists to separate fossil fuel emissions from those due to the natural annual cycle of the biosphere, demonstrating a long-term change in the seasonal exchange of CO_2 between the atmosphere, biosphere and ocean. Later observations of parallel trends in the atmospheric abundances of the $^{13}CO_2$ isotope (Francey and Farquhar, 1982) and molecular oxygen (O_2) (Keeling and Shertz, 1992; Bender et al., 1996) uniquely identified this rise in CO_2 with fossil fuel burning (Sections 2.3, 7.1 and 7.3).

To place the increase in CO_2 abundance since the late 1950s in perspective, and to compare the magnitude of the anthropogenic increase with natural cycles in the past, a longer-term record of CO_2 and other natural greenhouse gases is needed. These data came from analysis of the composition of air enclosed in bubbles in ice cores from Greenland and Antarctica. The initial measurements demonstrated that CO_2 abundances were significantly lower during the last ice age than over the last 10 kyr of the Holocene (Delmas et al., 1980; Berner et al., 1980; Neftel et al., 1982). From 10 kyr before present up to the year 1750, CO_2 abundances stayed within the range 280 ± 20 ppm (Indermühle et al., 1999). During the industrial era, CO_2 abundance rose roughly exponentially to 367 ppm in 1999 (Neftel et al., 1985; Etheridge et al., 1996; IPCC, 2001a) and to 379 ppm in 2005 (Section 2.3.1; see also Section 6.4).

Direct atmospheric measurements since 1970 (Steele et al., 1996) have also detected the increasing atmospheric abundances of two other major greenhouse gases, methane (CH_4) and nitrous oxide (N_2O). Methane abundances were initially increasing at a rate of about 1% yr^{-1} (Graedel and McRae, 1980; Fraser et al., 1981; Blake et al., 1982) but then slowed to an average increase of 0.4% yr^{-1} over the 1990s (Dlugokencky et al., 1998) with the possible stabilisation of CH_4 abundance (Section 2.3.2). The increase in N_2O abundance is smaller, about 0.25% yr^{-1}, and more difficult to detect (Weiss, 1981; Khalil and Rasmussen, 1988). To go back in time, measurements were made from firn air trapped in snowpack dating back over 200 years, and these data show an accelerating rise in both CH_4 and N_2O into the 20th century (Machida et al., 1995; Battle et al., 1996). When ice core measurements extended the CH_4 abundance back 1 kyr, they showed a stable, relatively constant abundance of 700 ppb until the 19th century when a steady increase brought CH_4 abundances to 1,745 ppb in 1998 (IPCC, 2001a) and 1,774 ppb in 2005 (Section 2.3.2). This peak abundance is much higher than the range of 400 to 700 ppb seen over the last half-million years of glacial-interglacial cycles, and the increase can be readily explained by anthropogenic emissions. For N_2O the results are similar: the relative increase over the industrial era is smaller (15%), yet the 1998 abundance of 314 ppb (IPCC, 2001a), rising to 319 ppb in 2005 (Section 2.3.3), is also well above the 180-to-260 ppb range of glacial-interglacial cycles (Flückiger et al., 1999; see Sections 2.3, 6.2, 6.3, 6.4, 7.1 and 7.4)

Several synthetic halocarbons (chlorofluorocarbons (CFCs), hydrofluorocarbons, perfluorocarbons, halons and sulphur hexafluoride) are greenhouse gases with large global warming potentials (GWPs; Section 2.10). The chemical industry has been producing these gases and they have been leaking into the atmosphere since about 1930. Lovelock (1971) first measured CFC-11 ($CFCl_3$) in the atmosphere, noting that it could serve as an artificial tracer, with its north-south gradient reflecting the latitudinal distribution of anthropogenic emissions. Atmospheric abundances of all the synthetic halocarbons were increasing until the 1990s, when the abundance of halocarbons phased out under the Montreal Protocol began to fall (Montzka et al., 1999; Prinn et al., 2000). In the case of synthetic halocarbons (except perfluoromethane), ice core research has shown that these compounds did not exist in ancient air (Langenfelds et al., 1996) and thus confirms their industrial human origin (see Sections 2.3 and 7.1).

At the time of the TAR scientists could say that the abundances of all the well-mixed greenhouse gases during the 1990s were greater than at any time during the last half-million years (Petit et al, 1999), and this record now extends back nearly one million years (Section 6.3). Given this daunting picture of increasing greenhouse gas abundances in the atmosphere, it is noteworthy that, for simpler challenges but still on a hemispheric or even global scale, humans have shown the ability to undo what they have done. Sulphate pollution in Greenland was reversed in the 1980s with the control of acid rain in North America and Europe (IPCC, 2001b), and CFC abundances are declining globally because of their phase-out undertaken to protect the ozone layer.

1.3.2 Global Surface Temperature

Shortly after the invention of the thermometer in the early 1600s, efforts began to quantify and record the weather. The first meteorological network was formed in northern Italy in 1653 (Kington, 1988) and reports of temperature observations were published in the earliest scientific journals (e.g., Wallis and Beale, 1669). By the latter part of the 19th century, systematic observations of the weather were being made in almost all inhabited areas of the world. Formal international coordination of meteorological observations from ships commenced in 1853 (Quetelet, 1854).

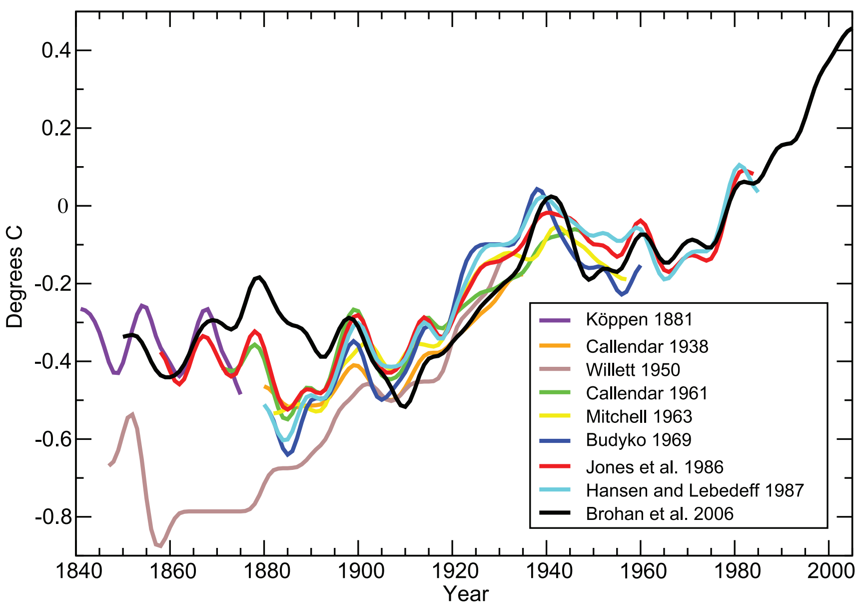


Figure 1.3. *Published records of surface temperature change over large regions. Köppen (1881) tropics and temperate latitudes using land air temperature. Callendar (1938) global using land stations. Willett (1950) global using land stations. Callendar (1961) 60°N to 60°S using land stations. Mitchell (1963) global using land stations. Budyko (1969) Northern Hemisphere using land stations and ship reports. Jones et al. (1986a,b) global using land stations. Hansen and Lebedeff (1987) global using land stations. Brohan et al. (2006) global using land air temperature and sea surface temperature data is the longest of the currently updated global temperature time series (Section 3.2). All time series were smoothed using a 13-point filter. The Brohan et al. (2006) time series are anomalies from the 1961 to 1990 mean (°C). Each of the other time series was originally presented as anomalies from the mean temperature of a specific and differing base period. To make them comparable, the other time series have been adjusted to have the mean of their last 30 years identical to that same period in the Brohan et al. (2006) anomaly time series.*

Inspired by the paper *Suggestions on a Uniform System of Meteorological Observations* (Buys-Ballot, 1872), the International Meteorological Organization (IMO) was formed in 1873. Its successor, the World Meteorological Organization (WMO), still works to promote and exchange standardised meteorological observations. Yet even with uniform observations, there are still four major obstacles to turning instrumental observations into accurate global time series: (1) access to the data in usable form; (2) quality control to remove or edit erroneous data points; (3) homogeneity assessments and adjustments where necessary to ensure the fidelity of the data; and (4) area-averaging in the presence of substantial gaps.

Köppen (1873, 1880, 1881) was the first scientist to overcome most of these obstacles in his quest to study the effect of changes in sunspots (Section 2.7). Much of his data came from Dove (1852), but wherever possible he used data directly from the original source, because Dove often lacked information about the observing methods. Köppen considered examination of the annual mean temperature to be an adequate technique for quality control of far distant stations. Using data from more than 100 stations, Köppen averaged annual observations into several major latitude belts and then area-averaged these into a near-global time series shown in Figure 1.3.

Callendar (1938) produced the next global temperature time series expressly to investigate the influence of CO_2 on temperature (Section 2.3). Callendar examined about 200 station records. Only a small portion of them were deemed defective, based on quality concerns determined by comparing differences with neighbouring stations or on homogeneity concerns based on station changes documented in the recorded metadata. After further removing two arctic stations because he had no compensating stations from the antarctic region, he created a global average using data from 147 stations.

Most of Callendar's data came from World Weather Records (WWR; Clayton, 1927). Initiated by a resolution at the 1923 IMO Conference, WWR was a monumental international undertaking producing a 1,196-page volume of monthly temperature, precipitation and pressure data from hundreds of stations around the world, some with data starting in the early 1800s. In the early 1960s, J. Wolbach had these data digitised (National Climatic Data Center, 2002). The WWR project continues today under the auspices of the WMO with the digital publication of decadal updates to the climate records for thousands of stations worldwide (National Climatic Data Center, 2005).

Willett (1950) also used WWR as the main source of data for 129 stations that he used to create a global temperature time series going back to 1845. While the resolution that initiated WWR called for the publication of long and homogeneous records, Willett took this mandate one step further by carefully selecting a subset of stations with as continuous and homogeneous a record as possible from the most recent update of WWR, which included data through 1940. To avoid over-weighting certain areas such as Europe, only one record, the best available, was included from each 10° latitude and longitude square. Station monthly data were averaged into five-year periods and then converted to anomalies with respect to the five-year period 1935 to 1939. Each station's anomaly was given equal weight to create the global time series.

Callendar in turn created a new near-global temperature time series in 1961 and cited Willett (1950) as a guide for some of his improvements. Callendar (1961) evaluated 600 stations with about three-quarters of them passing his quality checks. Unbeknownst to Callendar, a former student of Willett, Mitchell (1963), in work first presented in 1961, had created his own updated global temperature time series using slightly fewer than 200 stations and averaging the data into latitude bands. Landsberg and Mitchell (1961) compared Callendar's results with Mitchell's and stated that there was generally good agreement except in the data-sparse regions of the Southern Hemisphere.

Meanwhile, research in Russia was proceeding on a very different method to produce large-scale time series. Budyko (1969) used smoothed, hand-drawn maps of monthly temperature anomalies as a starting point. While restricted to analysis of the NH, this map-based approach not only allowed the inclusion of an increasing number of stations over time (e.g., 246 in 1881, 753 in 1913, 976 in 1940 and about 2,000 in 1960) but also the utilisation of data over the oceans (Robock, 1982).

Increasing the number of stations utilised has been a continuing theme over the last several decades with considerable effort being spent digitising historical station data as well as addressing the continuing problem of acquiring up-to-date data, as there can be a long lag between making an observation and the data getting into global data sets. During the 1970s and 1980s, several teams produced global temperature time series. Advances especially worth noting during this period include the extended spatial interpolation and station averaging technique of Hansen and Lebedeff (1987) and the Jones et al. (1986a,b) painstaking assessment of homogeneity and adjustments to account for discontinuities in the record of each of the thousands of stations in a global data set. Since then, global and national data sets have been rigorously adjusted for homogeneity using a variety of statistical and metadata-based approaches (Peterson et al., 1998).

One recurring homogeneity concern is potential urban heat island contamination in global temperature time series. This concern has been addressed in two ways. The first is by adjusting the temperature of urban stations to account for assessed urban heat island effects (e.g., Karl et al., 1988; Hansen et al., 2001). The second is by performing analyses that, like Callendar (1938), indicate that the bias induced by urban heat islands in the global temperature time series is either minor or non-existent (Jones et al., 1990; Peterson et al., 1999).

As the importance of ocean data became increasingly recognised, a major effort was initiated to seek out, digitise and quality-control historical archives of ocean data. This work has since grown into the International Comprehensive Ocean-Atmosphere Data Set (ICOADS; Worley et al., 2005), which has coordinated the acquisition, digitisation and synthesis of data ranging from transmissions by Japanese merchant ships to the logbooks of South African whaling boats. The amount of sea surface temperature (SST) and related data acquired continues to grow.

As fundamental as the basic data work of ICOADS was, there have been two other major advances in SST data. The first was adjusting the early observations to make them comparable to current observations (Section 3.2). Prior to 1940, the majority of SST observations were made from ships by hauling a bucket on deck filled with surface water and placing a thermometer in it. This ancient method eventually gave way to thermometers placed in engine cooling water inlets, which are typically located several metres below the ocean surface. Folland and Parker (1995) developed an adjustment model that accounted for heat loss from the buckets and that varied with bucket size and type, exposure to solar radiation, ambient wind speed and ship speed. They verified their results using time series of night marine air temperature. This adjusted the early bucket observations upwards by a few tenths of a degree celsius.

Most of the ship observations are taken in narrow shipping lanes, so the second advance has been increasing global coverage in a variety of ways. Direct improvement of coverage has been achieved by the internationally coordinated placement of drifting and moored buoys. The buoys began to be numerous enough to make significant contributions to SST analyses in the mid-1980s (McPhaden et al., 1998) and have subsequently increased to more than 1,000 buoys transmitting data at any one time. Since 1982, satellite data, anchored to *in situ* observations, have contributed to near-global coverage (Reynolds and Smith, 1994). In addition, several different approaches have been used to interpolate and combine land and ocean observations into the current global temperature time series (Section 3.2). To place the current instrumental observations into a longer historical context requires the use of proxy data (Section 6.2).

Figure 1.3 depicts several historical 'global' temperature time series, together with the longest of the current global temperature time series, that of Brohan et al. (2006; Section 3.2). While the data and the analysis techniques have changed over time, all the time series show a high degree of consistency since 1900. The differences caused by using alternate data sources and interpolation techniques increase when the data are sparser. This phenomenon is especially illustrated by the pre-1880 values of Willett's (1950) time series. Willett noted that his data coverage remained fairly constant after 1885 but dropped off dramatically before that time to only 11 stations before 1850. The high degree of agreement between the time series resulting from these many different analyses increases the confidence that the changes they are indicating are real.

Despite the fact that many recent observations are automatic, the vast majority of data that go into global surface temperature calculations – over 400 million individual readings of thermometers at land stations and over 140 million individual *in situ* SST observations – have depended on the dedication of tens of thousands of individuals for well over a century. Climate science owes a great debt to the work of these individual weather observers as well as to international organisations such as the IMO, WMO and the Global Climate Observing System, which encourage the taking and sharing of high-quality meteorological observations. While modern researchers and their institutions put a great deal of time and effort into acquiring and adjusting the data to account for all known problems and biases, century-scale global temperature time series would not have been possible without the conscientious work of individuals and organisations worldwide dedicated to quantifying and documenting their local environment (Section 3.2).

1.3.3 Detection and Attribution

Using knowledge of past climates to qualify the nature of ongoing changes has become a concern of growing importance during the last decades, as reflected in the successive IPCC reports. While linked together at a technical level, detection and attribution have separate objectives. Detection of climate change is the process of demonstrating that climate has changed in some defined statistical sense, without providing a reason for that change. Attribution of causes of climate change is the process of establishing the most likely causes for the detected change with some defined level of confidence. Using traditional approaches, unequivocal attribution would require controlled experimentation with our climate system. However, with no spare Earth with which to experiment, attribution of anthropogenic climate change must be pursued by: (a) detecting that the climate has changed (as defined above); (b) demonstrating that the detected change is consistent with computer model simulations of the climate change 'signal' that is calculated to occur in response to anthropogenic forcing; and (c) demonstrating that the detected change is not consistent with alternative, physically plausible explanations of recent climate change that exclude important anthropogenic forcings.

Both detection and attribution rely on observational data and model output. In spite of the efforts described in Section 1.3.2, estimates of century-scale natural climate fluctuations remain difficult to obtain directly from observations due to the relatively short length of most observational records and a lack of understanding of the full range and effects of the various and ongoing external influences. Model simulations with no changes in external forcing (e.g., no increases in atmospheric CO_2 concentration) provide valuable information on the natural internal variability of the climate system on time scales of years to centuries. Attribution, on the other hand, requires output from model runs that incorporate historical estimates of changes in key anthropogenic and natural forcings, such as well-mixed greenhouse gases, volcanic aerosols and solar irradiance. These simulations can be performed with changes in a single forcing only (which helps to isolate the climate effect of that forcing), or with simultaneous changes in a whole suite of forcings.

In the early years of detection and attribution research, the focus was on a single time series – the estimated global-mean changes in the Earth's surface temperature. While it was not possible to detect anthropogenic warming in 1980, Madden and Ramanathan (1980) and Hansen et al. (1981) predicted it would be evident at least within the next two decades. A decade later, Wigley and Raper (1990) used a simple energy-balance climate model to show that the observed change in global-mean surface temperature from 1867 to 1982 could not be explained by natural internal variability. This finding was later confirmed using variability estimates from more complex coupled ocean-atmosphere general circulation models (e.g., Stouffer et al., 1994).

As the science of climate change progressed, detection and attribution research ventured into more sophisticated statistical analyses that examined complex patterns of climate change. Climate change patterns or 'fingerprints' were no longer limited to a single variable (temperature) or to the Earth's surface. More recent detection and attribution work has made use of precipitation and global pressure patterns, and analysis of vertical profiles of temperature change in the ocean and atmosphere. Studies with multiple variables make it easier to address attribution issues. While two different climate forcings may yield similar changes in global mean temperature, it is highly unlikely that they will produce exactly the same 'fingerprint' (i.e., climate changes that are identical as a function of latitude, longitude, height, season and history over the 20th century).

Such model-predicted fingerprints of anthropogenic climate change are clearly statistically identifiable in observed data. The common conclusion of a wide range of fingerprint studies conducted over the past 15 years is that observed climate changes cannot be explained by natural factors alone (Santer et al., 1995, 1996a,b,c; Hegerl et al., 1996, 1997, 2000; Hasselmann, 1997; Barnett et al., 1999; Tett et al., 1999; Stott et al., 2000). A substantial anthropogenic influence is required in order to best explain the observed changes. The evidence from this body of work strengthens the scientific case for a discernible human influence on global climate.

1.4 Examples of Progress in Understanding Climate Processes

1.4.1 The Earth's Greenhouse Effect

The realisation that Earth's climate might be sensitive to the atmospheric concentrations of gases that create a greenhouse effect is more than a century old. Fleming (1998) and Weart (2003) provided an overview of the emerging science. In terms of the energy balance of the climate system, Edme Mariotte noted in 1681 that although the Sun's light and heat easily pass through glass and other transparent materials, heat from other sources (*chaleur de feu*) does not. The ability to generate an artificial warming of the Earth's surface was demonstrated in simple greenhouse experiments such as Horace Benedict de Saussure's experiments in the 1760s using a 'heliothermometer' (panes of glass covering a thermometer in a darkened box) to provide an early analogy to the greenhouse effect. It was a conceptual leap to recognise that the air itself could also trap thermal radiation. In 1824, Joseph Fourier, citing Saussure, argued 'the temperature [of the Earth] can be augmented by the interposition of the atmosphere, because heat in the state of light finds less resistance in penetrating the air, than in repassing into the air when converted into non-luminous heat'. In 1836, Pouillit followed up on Fourier's ideas and argued 'the atmospheric stratum…exercises a greater absorption upon the terrestrial than on the solar rays'. There was still no understanding of exactly what substance in the atmosphere was responsible for this absorption.

In 1859, John Tyndall (1861) identified through laboratory experiments the absorption of thermal radiation by complex molecules (as opposed to the primary bimolecular atmospheric constituents O_2 and molecular nitrogen). He noted that changes in the amount of any of the radiatively active constituents of the atmosphere such as water (H_2O) or CO_2 could have produced 'all the mutations of climate which the researches of geologists

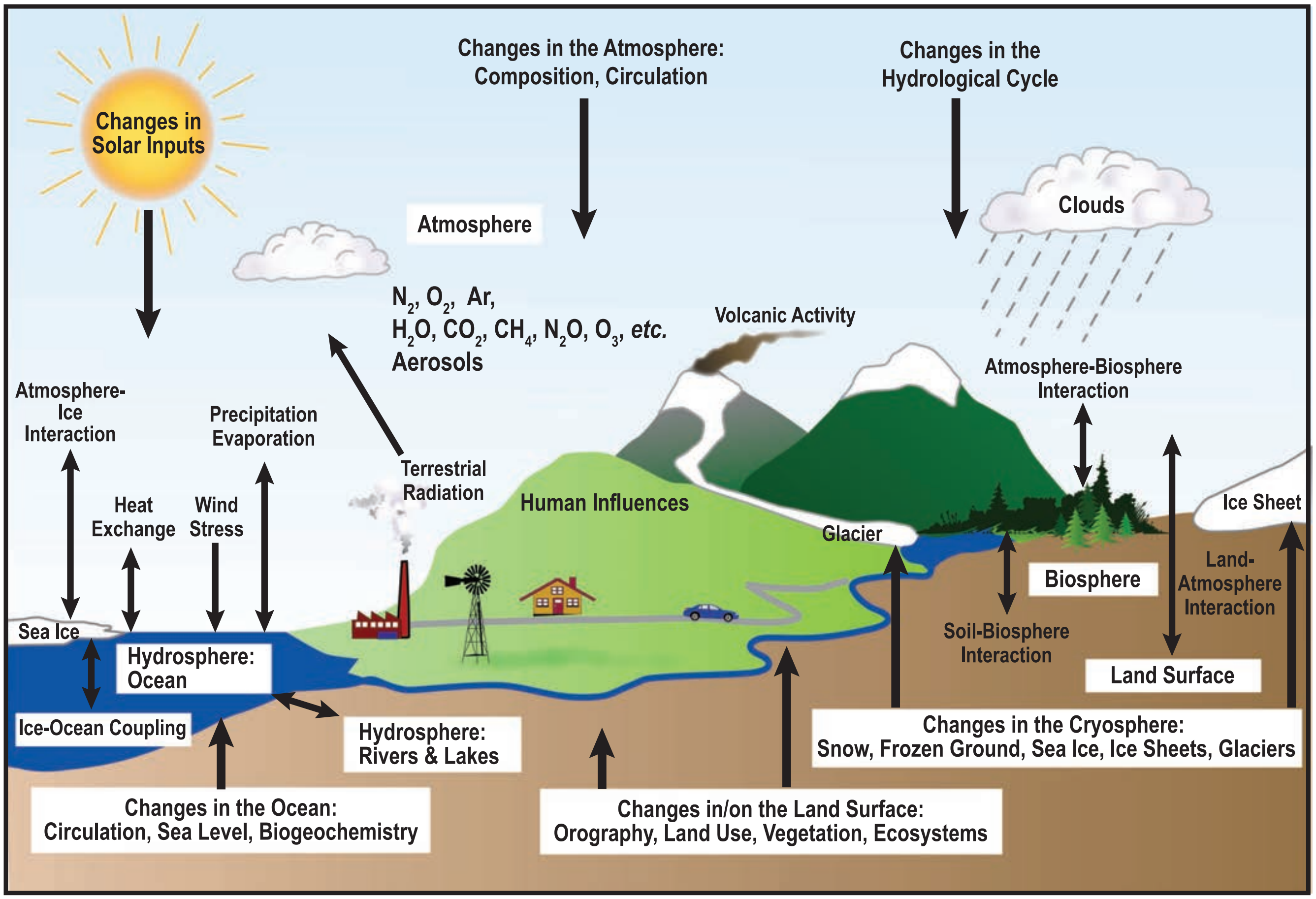
Frequently Asked Question 1.2

What is the Relationship between Climate Change and Weather?

Climate is generally defined as average weather, and as such, climate change and weather are intertwined. Observations can show that there have been changes in weather, and it is the statistics of changes in weather over time that identify climate change. While weather and climate are closely related, there are important differences. A common confusion between weather and climate arises when scientists are asked how they can predict climate 50 years from now when they cannot predict the weather a few weeks from now. The chaotic nature of weather makes it unpredictable beyond a few days. Projecting changes in climate (i.e., long-term average weather) due to changes in atmospheric composition or other factors is a very different and much more manageable issue. As an analogy, while it is impossible to predict the age at which any particular man will die, we can say with high confidence that the average age of death for men in industrialised countries is about 75. Another common confusion of these issues is thinking that a cold winter or a cooling spot on the globe is evidence against global warming. There are always extremes of hot and cold, although their frequency and intensity change as climate changes. But when weather is averaged over space and time, the fact that the globe is warming emerges clearly from the data.

Meteorologists put a great deal of effort into observing, understanding and predicting the day-to-day evolution of weather systems. Using physics-based concepts that govern how the atmosphere moves, warms, cools, rains, snows, and evaporates water, meteorologists are typically able to predict the weather successfully several days into the future. A major limiting factor to the predictability of weather beyond several days is a fundamental dynamical property of the atmosphere. In the 1960s, meteorologist Edward Lorenz discovered that very slight differences in initial conditions can produce very different forecast results.

(continued)



FAQ 1.2, Figure 1. *Schematic view of the components of the climate system, their processes and interactions.*

This is the so-called butterfly effect: a butterfly flapping its wings (or some other small phenomenon) in one place can, in principle, alter the subsequent weather pattern in a distant place. At the core of this effect is chaos theory, which deals with how small changes in certain variables can cause apparent randomness in complex systems.

Nevertheless, chaos theory does not imply a total lack of order. For example, slightly different conditions early in its history might alter the day a storm system would arrive or the exact path it would take, but the average temperature and precipitation (that is, climate) would still be about the same for that region and that period of time. Because a significant problem facing weather forecasting is knowing all the conditions at the start of the forecast period, it can be useful to think of climate as dealing with the background conditions for weather. More precisely, climate can be viewed as concerning the status of the entire Earth system, including the atmosphere, land, oceans, snow, ice and living things (see Figure 1) that serve as the global background conditions that determine weather patterns. An example of this would be an El Niño affecting the weather in coastal Peru. The El Niño sets limits on the probable evolution of weather patterns that random effects can produce. A La Niña would set different limits.

Another example is found in the familiar contrast between summer and winter. The march of the seasons is due to changes in the geographical patterns of energy absorbed and radiated away by the Earth system. Likewise, projections of future climate are shaped by fundamental changes in heat energy in the Earth system, in particular the increasing intensity of the greenhouse effect that traps heat near Earth's surface, determined by the amount of carbon dioxide and other greenhouse gases in the atmosphere. Projecting changes in climate due to changes in greenhouse gases 50 years from now is a very different and much more easily solved problem than forecasting weather patterns just weeks from now. To put it another way, long-term variations brought about by changes in the composition of the atmosphere are much more predictable than individual weather events. As an example, while we cannot predict the outcome of a single coin toss or roll of the dice, we can predict the statistical behaviour of a large number of such trials.

While many factors continue to influence climate, scientists have determined that human activities have become a dominant force, and are responsible for most of the warming observed over the past 50 years. Human-caused climate change has resulted primarily from changes in the amounts of greenhouse gases in the atmosphere, but also from changes in small particles (aerosols), as well as from changes in land use, for example. As climate changes, the probabilities of certain types of weather events are affected. For example, as Earth's average temperature has increased, some weather phenomena have become more frequent and intense (e.g., heat waves and heavy downpours), while others have become less frequent and intense (e.g., extreme cold events).

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reveal'. In 1895, Svante Arrhenius (1896) followed with a climate prediction based on greenhouse gases, suggesting that a 40% increase or decrease in the atmospheric abundance of the trace gas CO_2 might trigger the glacial advances and retreats. One hundred years later, it would be found that CO_2 did indeed vary by this amount between glacial and interglacial periods. However, it now appears that the initial climatic change preceded the change in CO_2 but was enhanced by it (Section 6.4).

G. S. Callendar (1938) solved a set of equations linking greenhouse gases and climate change. He found that a doubling of atmospheric CO_2 concentration resulted in an increase in the mean global temperature of 2°C, with considerably more warming at the poles, and linked increasing fossil fuel combustion with a rise in CO_2 and its greenhouse effects: 'As man is now changing the composition of the atmosphere at a rate which must be very exceptional on the geological time scale, it is natural to seek for the probable effects of such a change. From the best laboratory observations it appears that the principal result of increasing atmospheric carbon dioxide… would be a gradual increase in the mean temperature of the colder regions of the Earth.' In 1947, Ahlmann reported a 1.3°C warming in the North Atlantic sector of the Arctic since the 19th century and mistakenly believed this climate variation could be explained entirely by greenhouse gas warming. Similar model predictions were echoed by Plass in 1956 (see Fleming, 1998): 'If at the end of this century, measurements show that the carbon dioxide content of the atmosphere has risen appreciably and at the same time the temperature has continued to rise throughout the world, it will be firmly established that carbon dioxide is an important factor in causing climatic change' (see Chapter 9).

In trying to understand the carbon cycle, and specifically how fossil fuel emissions would change atmospheric CO_2, the interdisciplinary field of carbon cycle science began. One of the first problems addressed was the atmosphere-ocean exchange of CO_2. Revelle and Suess (1957) explained why part of the emitted CO_2 was observed to accumulate in the atmosphere rather than being completely absorbed by the oceans. While CO_2 can be mixed rapidly into the upper layers of the ocean, the time to mix with the deep ocean is many centuries. By the time of the TAR, the interaction of climate change with the oceanic circulation and biogeochemistry was projected to reduce the fraction of anthropogenic CO_2 emissions taken up by the oceans in the future, leaving a greater fraction in the atmosphere (Sections 7.1, 7.3 and 10.4).

In the 1950s, the greenhouse gases of concern remained CO_2 and H_2O, the same two identified by Tyndall a century earlier. It was not until the 1970s that other greenhouse gases – CH_4, N_2O and CFCs – were widely recognised as important anthropogenic greenhouse gases (Ramanathan, 1975; Wang et al., 1976; Section 2.3). By the 1970s, the importance of aerosol-cloud effects in reflecting sunlight was known (Twomey, 1977), and atmospheric aerosols (suspended small particles) were being proposed as climate-forcing constituents. Charlson and others (summarised in Charlson et al., 1990) built a consensus that sulphate aerosols were, by themselves, cooling the Earth's surface by directly reflecting sunlight. Moreover, the increases in sulphate aerosols were anthropogenic and linked with the main source of CO_2, burning of fossil fuels (Section 2.4). Thus, the current picture of the atmospheric constituents driving climate change contains a much more diverse mix of greenhouse agents.

1.4.2 Past Climate Observations, Astronomical Theory and Abrupt Climate Changes

Throughout the 19th and 20th centuries, a wide range of geomorphology and palaeontology studies has provided new insight into the Earth's past climates, covering periods of hundreds of millions of years. The Palaeozoic Era, beginning 600 Ma, displayed evidence of both warmer and colder climatic conditions than the present; the Tertiary Period (65 to 2.6 Ma) was generally warmer; and the Quaternary Period (2.6 Ma to the present – the ice ages) showed oscillations between glacial and interglacial conditions. Louis Agassiz (1837) developed the hypothesis that Europe had experienced past glacial ages, and there has since been a growing awareness that long-term climate observations can advance the understanding of the physical mechanisms affecting climate change. The scientific study of one such mechanism – modifications in the geographical and temporal patterns of solar energy reaching the Earth's surface due to changes in the Earth's orbital parameters – has a long history. The pioneering contributions of Milankovitch (1941) to this astronomical theory of climate change are widely known, and the historical review of Imbrie and Imbrie (1979) calls attention to much earlier contributions, such as those of James Croll, originating in 1864.

The pace of palaeoclimatic research has accelerated over recent decades. Quantitative and well-dated records of climate fluctuations over the last 100 kyr have brought a more comprehensive view of how climate changes occur, as well as the means to test elements of the astronomical theory. By the 1950s, studies of deep-sea cores suggested that the ocean temperatures may have been different during glacial times (Emiliani, 1955). Ewing and Donn (1956) proposed that changes in ocean circulation actually could initiate an ice age. In the 1960s, the works of Emiliani (1969) and Shackleton (1967) showed the potential of isotopic measurements in deep-sea sediments to help explain Quaternary changes. In the 1970s, it became possible to analyse a deep-sea core time series of more than 700 kyr, thereby using the last reversal of the Earth's magnetic field to establish a dated chronology. This deep-sea observational record clearly showed the same periodicities found in the astronomical forcing, immediately providing strong support to Milankovitch's theory (Hays et al., 1976).

Ice cores provide key information about past climates, including surface temperatures and atmospheric chemical composition. The bubbles sealed in the ice are the only available samples of these past atmospheres. The first deep ice cores from Vostok in Antarctica (Barnola et al., 1987; Jouzel et al., 1987, 1993) provided additional evidence of the role of astronomical forcing. They also revealed a highly correlated evolution of temperature changes and atmospheric composition, which was subsequently confirmed over the past 400 kyr (Petit et al., 1999) and now extends to almost 1 Myr. This discovery drove research to understand the causal links between greenhouse gases and climate change. The same data that confirmed the astronomical theory also revealed its limits: a linear response of the climate system to astronomical forcing could not explain entirely the observed fluctuations of rapid ice-age terminations preceded by longer cycles of glaciations.

The importance of other sources of climate variability was heightened by the discovery of abrupt climate changes. In this context, 'abrupt' designates regional events of large amplitude, typically a few degrees celsius, which occurred within several decades – much shorter than the thousand-year time scales that characterise changes in astronomical forcing. Abrupt temperature changes were first revealed by the analysis of deep ice cores from Greenland (Dansgaard et al., 1984). Oeschger et al. (1984) recognised that the abrupt changes during the termination of the last ice age correlated with cooling in Gerzensee (Switzerland) and suggested that regime shifts in the Atlantic Ocean circulation were causing these widespread changes. The synthesis of palaeoclimatic observations by Broecker and Denton (1989) invigorated the community over the next decade. By the end of the 1990s, it became clear that the abrupt climate changes during the last ice age, particularly in the North Atlantic regions as found in the Greenland ice cores, were numerous (Dansgaard et al., 1993), indeed abrupt (Alley et al., 1993) and of large amplitude (Severinghaus and Brook, 1999). They are now referred to as Dansgaard-Oeschger events. A similar variability is seen in the North Atlantic Ocean, with north-south oscillations of the polar front (Bond et al., 1992) and associated changes in ocean temperature and salinity (Cortijo et al., 1999). With no obvious external forcing, these changes are thought to be manifestations of the internal variability of the climate system.

The importance of internal variability and processes was reinforced in the early 1990s with analysis of records with high temporal resolution. New ice cores (Greenland Ice Core Project, Johnsen et al., 1992; Greenland Ice Sheet Project 2, Grootes et al., 1993), new ocean cores from regions with high sedimentation rates, as well as lacustrine sediments and cave stalagmites produced additional evidence for unforced climate changes, and revealed a large number of abrupt changes in many regions throughout the last glacial cycle. Long sediment cores from the deep ocean were used to reconstruct the thermohaline circulation connecting deep and surface waters (Bond et al., 1992; Broecker, 1997) and to demonstrate the participation of the ocean in these abrupt climate changes during glacial periods.

By the end of the 1990s, palaeoclimate proxies for a range of climate observations had expanded greatly. The analysis of deep corals provided indicators for nutrient content and mass exchange from the surface to deep water (Adkins et al., 1998), showing abrupt variations characterised by synchronous changes in surface and deep-water properties (Shackleton et al., 2000). Precise measurements of the CH_4 abundances (a global quantity) in polar ice cores showed that they changed in concert with the Dansgaard-Oeschger events and thus allowed for synchronisation of the dating across ice cores (Blunier et al., 1998). The characteristics of the antarctic temperature variations and their relation to the Dansgaard-Oeschger events in Greenland were consistent with the simple concept of a bipolar seesaw caused by changes in the thermohaline circulation of the Atlantic Ocean (Stocker, 1998). This work underlined the role of the ocean in transmitting the signals of abrupt climate change.

Abrupt changes are often regional, for example, severe droughts lasting for many years have changed civilizations, and have occurred during the last 10 kyr of stable warm climate (deMenocal, 2001). This result has altered the notion of a stable climate during warm epochs, as previously suggested by the polar ice cores. The emerging picture of an unstable ocean-atmosphere system has opened the debate of whether human interference through greenhouse gases and aerosols could trigger such events (Broecker, 1997).

Palaeoclimate reconstructions cited in the FAR were based on various data, including pollen records, insect and animal remains, oxygen isotopes and other geological data from lake varves, loess, ocean sediments, ice cores and glacier termini. These records provided estimates of climate variability on time scales up to millions of years. A climate proxy is a local quantitative record (e.g., thickness and chemical properties of tree rings, pollen of different species) that is interpreted as a climate variable (e.g., temperature or rainfall) using a transfer function that is based on physical principles and recently observed correlations between the two records. The combination of instrumental and proxy data began in the 1960s with the investigation of the influence of climate on the proxy data, including tree rings (Fritts, 1962), corals (Weber and Woodhead, 1972; Dunbar and Wellington, 1981) and ice cores (Dansgaard et al., 1984; Jouzel et al., 1987). Phenological and historical data (e.g., blossoming dates, harvest dates, grain prices, ships' logs, newspapers, weather diaries, ancient manuscripts) are also a valuable source of climatic reconstruction for the period before instrumental records became available. Such documentary data also need calibration against instrumental data to extend and reconstruct the instrumental record (Lamb, 1969; Zhu, 1973; van den Dool, 1978; Brazdil, 1992; Pfister, 1992). With the development of multi-proxy reconstructions, the climate data were extended not only from local to global, but also from instrumental data to patterns of climate variability (Wanner et al., 1995; Mann et al., 1998; Luterbacher et al., 1999). Most of these reconstructions were at single sites and only loose efforts had been made to consolidate records. Mann et al. (1998) made a notable advance in the use of proxy data by ensuring that the dating of different records lined up. Thus, the true spatial patterns of temperature variability and change could be derived, and estimates of NH average surface temperatures were obtained.

The Working Group I (WGI) WGI FAR noted that past climates could provide analogues. Fifteen years of research since that assessment has identified a range of variations and instabilities in the climate system that occurred during the last 2 Myr of glacial-interglacial cycles and in the super-warm period of 50 Ma. These past climates do not appear to be analogues of the immediate future, yet they do reveal a wide range of climate processes that need to be understood when projecting 21st-century climate change (see Chapter 6).

1.4.3 Solar Variability and the Total Solar Irradiance

Measurement of the absolute value of total solar irradiance (TSI) is difficult from the Earth's surface because of the need to correct for the influence of the atmosphere. Langley (1884) attempted to minimise the atmospheric effects by taking measurements from high on Mt. Whitney in California, and to estimate the correction for atmospheric effects by taking measurements at several times of day, for example, with the solar radiation having passed through different atmospheric pathlengths. Between 1902 and 1957, Charles Abbot and a number of other scientists around the globe made thousands of measurements of TSI from mountain sites. Values ranged from 1,322 to 1,465 W m^{-2}, which encompasses the current estimate of 1,365 W m^{-2}. Foukal et al. (1977) deduced from Abbot's daily observations that higher values of TSI were associated with more solar faculae (e.g., Abbot, 1910).

In 1978, the Nimbus-7 satellite was launched with a cavity radiometer and provided evidence of variations in TSI (Hickey et al., 1980). Additional observations were made with an active cavity radiometer on the Solar Maximum Mission, launched in 1980 (Willson et al., 1980). Both of these missions showed that the passage of sunspots and faculae across the Sun's disk influenced TSI. At the maximum of the 11-year solar activity cycle, the TSI is larger by about 0.1% than at the minimum. The observation that TSI is highest when sunspots are at their maximum is the opposite of Langley's (1876) hypothesis.

As early as 1910, Abbot believed that he had detected a downward trend in TSI that coincided with a general cooling of climate. The solar cycle variation in irradiance corresponds to an 11-year cycle in radiative forcing which varies by about 0.2 W m^{-2}. There is increasingly reliable evidence of its influence on atmospheric temperatures and circulations, particularly in the higher atmosphere (Reid, 1991; Brasseur, 1993; Balachandran and Rind, 1995; Haigh, 1996; Labitzke and van Loon, 1997; van Loon and Labitzke, 2000). Calculations with three-dimensional models (Wetherald and Manabe, 1975; Cubasch et al., 1997; Lean and Rind, 1998; Tett et al., 1999; Cubasch and Voss, 2000) suggest that the changes in solar radiation could cause surface temperature changes of the order of a few tenths of a degree celsius.

For the time before satellite measurements became available, the solar radiation variations can be inferred from cosmogenic isotopes (^{10}Be, ^{14}C) and from the sunspot number. Naked-eye observations of sunspots date back to ancient times, but it was only after the invention of the telescope in 1607 that it became possible to routinely monitor the number, size and position of these 'stains' on the surface of the Sun. Throughout the 17th and 18th centuries, numerous observers noted the variable concentrations and ephemeral nature of sunspots, but very few sightings were reported between 1672 and 1699 (for an overview see Hoyt et al., 1994). This period of low solar activity, now known as the Maunder Minimum, occurred during the climate period now commonly referred to as the Little Ice Age (Eddy, 1976). There is no exact agreement as to which dates mark the beginning and end of the Little Ice Age, but from about 1350 to about 1850 is one reasonable estimate.

During the latter part of the 18th century, Wilhelm Herschel (1801) noted the presence not only of sunspots but of bright patches, now referred to as faculae, and of granulations on the solar surface. He believed that when these indicators of activity were more numerous, solar emissions of light and heat were greater and could affect the weather on Earth. Heinrich Schwabe (1844) published his discovery of a '10-year cycle' in sunspot numbers. Samuel Langley (1876) compared the brightness of sunspots with that of the surrounding photosphere. He concluded that they would block the emission of radiation and estimated that at sunspot cycle maximum the Sun would be about 0.1% less bright than at the minimum of the cycle, and that the Earth would be 0.1°C to 0.3°C cooler.

These satellite data have been used in combination with the historically recorded sunspot number, records of cosmogenic isotopes, and the characteristics of other Sun-like stars to estimate the solar radiation over the last 1,000 years (Eddy, 1976; Hoyt and Schatten, 1993, 1997; Lean et al., 1995; Lean, 1997). These data sets indicated quasi-periodic changes in solar radiation of 0.24 to 0.30% on the centennial time scale. These values have recently been re-assessed (see, e.g., Chapter 2).

The TAR states that the changes in solar irradiance are not the major cause of the temperature changes in the second half of the 20th century unless those changes can induce unknown large feedbacks in the climate system. The effects of galactic cosmic rays on the atmosphere (via cloud nucleation) and those due to shifts in the solar spectrum towards the ultraviolet (UV) range, at times of high solar activity, are largely unknown. The latter may produce changes in tropospheric circulation via changes in static stability resulting from the interaction of the increased UV radiation with stratospheric ozone. More research to investigate the effects of solar behaviour on climate is needed before the magnitude of solar effects on climate can be stated with certainty.

1.4.4 Biogeochemistry and Radiative Forcing

The modern scientific understanding of the complex and interconnected roles of greenhouse gases and aerosols in climate change has undergone rapid evolution over the last two decades. While the concepts were recognised and outlined in the 1970s (see Sections 1.3.1 and 1.4.1), the publication of generally accepted quantitative results coincides with, and was driven in part by, the questions asked by the IPCC beginning in 1988. Thus, it is instructive to view the evolution of this topic as it has been treated in the successive IPCC reports.

The WGI FAR codified the key physical and biogeochemical processes in the Earth system that relate a changing climate to atmospheric composition, chemistry, the carbon cycle and natural ecosystems. The science of the time, as summarised in the FAR, made a clear case for anthropogenic interference with the climate system. In terms of greenhouse agents, the main conclusions from the WGI FAR Policymakers Summary are still valid today: (1) 'emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases: CO_2, CH_4, CFCs, N_2O'; (2) 'some gases are potentially more effective (at greenhouse warming)'; (3) feedbacks between the carbon cycle, ecosystems and atmospheric greenhouse gases in a warmer world will affect CO_2 abundances; and (4) GWPs provide a metric for comparing the climatic impact of different greenhouse gases, one that integrates both the radiative influence and biogeochemical cycles. The climatic importance of tropospheric ozone, sulphate aerosols and atmospheric chemical feedbacks were proposed by scientists at the time and noted in the assessment. For example, early global chemical modelling results argued that global tropospheric ozone, a greenhouse gas, was controlled by emissions of the highly reactive gases nitrogen oxides (NO_x), carbon monoxide (CO) and non-methane hydrocarbons (NMHC, also known as volatile organic compounds, VOC). In terms of sulphate aerosols, both the direct radiative effects and the indirect effects on clouds were acknowledged, but the importance of carbonaceous aerosols from fossil fuel and biomass combustion was not recognised (Chapters 2, 7 and 10).

The concept of radiative forcing (RF) as the radiative imbalance (W m^{-2}) in the climate system at the top of the atmosphere caused by the addition of a greenhouse gas (or other change) was established at the time and summarised in Chapter 2 of the WGI FAR. Agents of RF included the direct greenhouse gases, solar radiation, aerosols and the Earth's surface albedo. What was new and only briefly mentioned was that 'many gases produce indirect effects on the global radiative forcing'. The innovative global modelling work of Derwent (1990) showed that emissions of the reactive but non-greenhouse gases – NO_x, CO and NMHCs – altered atmospheric chemistry and thus changed the abundance of other greenhouse gases. Indirect GWPs for NO_x, CO and VOCs were proposed. The projected chemical feedbacks were limited to short-lived increases in tropospheric ozone. By 1990, it was clear that the RF from tropospheric ozone had increased over the 20th century and stratospheric ozone had decreased since 1980 (e.g., Lacis et al., 1990), but the associated RFs were not evaluated in the assessments. Neither was the effect of anthropogenic sulphate aerosols, except to note in the FAR that 'it is conceivable that this radiative forcing has been of a comparable magnitude, but of opposite sign, to the greenhouse forcing earlier in the century'. Reflecting in general the community's concerns about this relatively new measure of climate forcing, RF bar charts appear only in the underlying FAR chapters, but not in the FAR Summary. Only the long-lived greenhouse gases are shown, although sulphate aerosols direct effect in the future is noted with a question mark (i.e., dependent on future emissions) (Chapters 2, 7 and 10).

The cases for more complex chemical and aerosol effects were becoming clear, but the scientific community was unable at the time to reach general agreement on the existence, scale and magnitude of these indirect effects. Nevertheless, these early discoveries drove the research agendas in the early 1990s. The widespread development and application of global chemistry-transport models had just begun with international workshops (Pyle et al., 1996; Jacob et al., 1997; Rasch, 2000). In the Supplementary Report (IPCC, 1992) to the FAR, the indirect chemical effects of CO, NO_x and VOC were reaffirmed, and the feedback effect of CH_4 on the tropospheric hydroxyl radical (OH) was noted, but the indirect RF values from the FAR were retracted and denoted in a table with '+', '0' or '–'. Aerosol-climate interactions still focused on sulphates, and the assessment of their direct RF for the NH (i.e., a cooling) was now somewhat quantitative as compared to the FAR. Stratospheric ozone depletion was noted as causing a significant and negative RF, but not quantified. Ecosystems research at this time was identifying the responses to climate change and CO_2 increases, as well as altered CH_4 and N_2O fluxes from natural systems; however, in terms of a community assessment it remained qualitative.

By 1994, with work on SAR progressing, the Special Report on Radiative Forcing (IPCC, 1995) reported significant breakthroughs in a set of chapters limited to assessment of the carbon cycle, atmospheric chemistry, aerosols and RF. The carbon budget for the 1980s was analysed not only from bottom-up emissions estimates, but also from a top-down approach including carbon isotopes. A first carbon cycle assessment was performed through an international model and analysis workshop examining terrestrial and oceanic uptake to better quantify the relationship between CO_2 emissions and the resulting increase in atmospheric abundance. Similarly, expanded analyses of the global budgets of trace gases and aerosols from both natural and anthropogenic sources highlighted the rapid expansion of biogeochemical research. The first RF bar chart appears, comparing all the major components of RF change from the pre-industrial period to the present. Anthropogenic soot aerosol, with a positive RF, was not in the 1995 Special Report but was added to the SAR. In terms of atmospheric chemistry, the first open-invitation modelling study for the IPCC recruited 21 atmospheric chemistry models to participate in a controlled study of photochemistry and chemical feedbacks. These studies (e.g., Olson et al., 1997) demonstrated a robust consensus about some indirect effects, such as the CH_4 impact on atmospheric chemistry, but great uncertainty about others, such as the prediction of tropospheric ozone changes. The model studies plus the theory of chemical feedbacks in the CH_4-CO-OH system (Prather, 1994) firmly established that the atmospheric lifetime of a perturbation (and hence climate impact and GWP) of CH_4 emissions was about 50% greater than reported in the FAR. There was still no consensus on quantifying the past or future changes in tropospheric ozone or OH (the primary sink for CH_4) (Chapters 2, 7 and 10).

In the early 1990s, research on aerosols as climate forcing agents expanded. Based on new research, the range of climate-relevant aerosols was extended for the first time beyond sulphates to include nitrates, organics, soot, mineral dust and sea salt. Quantitative estimates of sulphate aerosol indirect effects on cloud properties and hence RF were sufficiently well established to be included in assessments, and carbonaceous aerosols from biomass burning were recognised as being comparable in importance to sulphate (Penner et al., 1992). Ranges are given in the special report (IPCC, 1995) for direct sulphate RF (–0.25 to –0.9 W m^{-2}) and biomass-burning aerosols (–0.05 to –0.6 W m^{-2}). The aerosol indirect RF was estimated to be about equal to the direct RF, but with larger uncertainty. The injection of stratospheric aerosols from the eruption of Mt. Pinatubo was noted as the first modern test of a known radiative forcing, and indeed one climate model accurately predicted the temperature response (Hansen et al., 1992). In the one-year interval between the special report and the SAR, the scientific understanding of aerosols grew. The direct anthropogenic aerosol forcing (from sulphate, fossil-fuel soot and biomass-burning aerosols) was reduced to –0.5 W m^{-2}. The RF bar chart was now broken into aerosol components (sulphate, fossil-fuel soot and biomass burning aerosols) with a separate range for indirect effects (Chapters 2 and 7; Sections 8.2 and 9.2).

Throughout the 1990s, there were concerted research programs in the USA and EU to evaluate the global environmental impacts of aviation. Several national assessments culminated in the IPCC Special Report on Aviation and the Global Atmosphere (IPCC, 1999), which assessed the impacts on climate and global air quality. An open invitation for atmospheric model participation resulted in community participation and a consensus on many of the environmental impacts of aviation (e.g., the increase in tropospheric ozone and decrease in CH_4 due to NO_x emissions were quantified). The direct RF of sulphate and of soot aerosols was likewise quantified along with that of contrails, but the impact on cirrus clouds that are sometimes generated downwind of contrails was not. The assessment re-affirmed that RF was a first-order metric for the global mean surface temperature response, but noted that it was inadequate for regional climate change, especially in view of the largely regional forcing from aerosols and tropospheric ozone (Sections 2.6, 2.8 and 10.2).

By the end of the 1990s, research on atmospheric composition and climate forcing had made many important advances. The TAR was able to provide a more quantitative evaluation in some areas. For example, a large, open-invitation modelling workshop was held for both aerosols (11 global models) and tropospheric ozone-OH chemistry (14 global models). This workshop brought together as collaborating authors most of the international scientific community involved in developing and testing global models of atmospheric composition. In terms of atmospheric chemistry, a strong consensus was reached for the first time that science could predict the changes in tropospheric ozone in response to scenarios for CH_4 and the indirect greenhouse gases (CO, NO_x, VOC) and that a quantitative GWP for CO could be reported. Further, combining these models with observational analysis, an estimate of the change in tropospheric ozone since the pre-industrial era – with uncertainties – was reported. The aerosol workshop made similar advances in evaluating the impact of different aerosol types. There were many different representations of uncertainty (e.g., a range in models versus an expert judgment) in the TAR, and the consensus RF bar chart did not generate a total RF or uncertainties for use in the subsequent IPCC Synthesis Report (IPCC, 2001b) (Chapters 2 and 7; Section 9.2).

1.4.5 Cryospheric Topics

The cryosphere, which includes the ice sheets of Greenland and Antarctica, continental (including tropical) glaciers, snow, sea ice, river and lake ice, permafrost and seasonally frozen ground, is an important component of the climate system. The cryosphere derives its importance to the climate system from a variety of effects, including its high reflectivity (albedo) for solar radiation, its low thermal conductivity, its large thermal inertia, its potential for affecting ocean circulation (through exchange of freshwater and heat) and atmospheric circulation (through topographic changes), its large potential for affecting sea level (through growth and melt of land ice), and its potential for affecting greenhouse gases (through changes in permafrost) (Chapter 4).

Studies of the cryospheric albedo feedback have a long history. The albedo is the fraction of solar energy reflected back to space. Over snow and ice, the albedo (about 0.7 to 0.9) is large compared to that over the oceans (<0.1). In a warming climate, it is anticipated that the cryosphere would shrink, the Earth's overall albedo would decrease and more solar energy would be absorbed to warm the Earth still further. This powerful feedback loop was recognised in the 19th century by Croll (1890) and was first introduced in climate models by Budyko (1969) and Sellers (1969). But although the principle of the albedo feedback is simple, a quantitative understanding of the effect is still far from complete. For instance, it is not clear whether this mechanism is the main reason for the high-latitude amplification of the warming signal.

The potential cryospheric impact on ocean circulation and sea level are of particular importance. There may be 'large-scale discontinuities' (IPCC, 2001a) resulting from both the shutdown of the large-scale meridional circulation of the world oceans (see Section 1.4.6) and the disintegration of large continental ice sheets. Mercer (1968, 1978) proposed that atmospheric warming could cause the ice shelves of western Antarctica to disintegrate and that as a consequence the entire West Antarctic Ice Sheet (10% of the antarctic ice volume) would lose its land connection and come afloat, causing a sea level rise of about five metres.

The importance of permafrost-climate feedbacks came to be realised widely only in the 1990s, starting with the works of Kvenvolden (1988, 1993), MacDonald (1990) and Harriss et al. (1993). As permafrost thaws due to a warmer climate, CO_2 and CH_4 trapped in permafrost are released to the atmosphere. Since CO_2 and CH_4 are greenhouse gases, atmospheric temperature is likely to increase in turn, resulting in a feedback loop with more permafrost thawing. The permafrost and seasonally thawed soil layers at high latitudes contain a significant amount (about one-quarter) of the global total amount of soil carbon. Because global warming signals are amplified in high-latitude regions, the potential for permafrost thawing and consequent greenhouse gas releases is thus large.

In situ monitoring of the cryosphere has a long tradition. For instance, it is important for fisheries and agriculture. Seagoing communities have documented sea ice extent for centuries. Records of thaw and freeze dates for lake and river ice start with Lake Suwa in Japan in 1444, and extensive records of snowfall in China were made during the Qing Dynasty (1644–1912). Records of glacial length go back to the mid-1500s. Internationally coordinated, long-term glacier observations started in 1894 with the establishment of the International Glacier Commission in Zurich, Switzerland. The longest time series of a glacial mass balance was started in 1946 at the Storglaciären in northern Sweden, followed by Storbreen in Norway (begun in 1949). Today a global network of mass balance monitoring for some 60 glaciers is coordinated through the World Glacier Monitoring Service. Systematic measurements of permafrost (thermal state and active layer) began in earnest around 1950 and were coordinated under the Global Terrestrial Network for Permafrost.

The main climate variables of the cryosphere (extent, albedo, topography and mass) are in principle observable from space, given proper calibration and validation through *in situ* observing efforts. Indeed, satellite data are required in order to have full global coverage. The polar-orbiting Nimbus 5 satellite, launched in 1972, yielded the earliest all-weather, all-season imagery of global sea ice, using microwave instruments (Parkinson et al., 1987), and enabled a major advance in the scientific understanding of the dynamics of the cryosphere. Launched in 1978, the Television Infrared Observation Satellite (TIROS-N) yielded the first monitoring from space of snow on land surfaces (Dozier et al., 1981). The number of cryospheric elements now routinely monitored from space is growing, and current satellites are now addressing one of the more challenging elements, variability of ice volume.

Climate modelling results have pointed to high-latitude regions as areas of particular importance and ecological vulnerability to global climate change. It might seem logical to expect that the cryosphere overall would shrink in a warming climate or expand in a cooling climate. However, potential changes in precipitation, for instance due to an altered hydrological cycle, may counter this effect both regionally and globally. By the time of the TAR, several climate models incorporated physically based treatments of ice dynamics, although the land ice processes were only rudimentary. Improving representation of the cryosphere in climate models is still an area of intense research and continuing progress (Chapter 8).

1.4.6 Ocean and Coupled Ocean-Atmosphere Dynamics

Developments in the understanding of the oceanic and atmospheric circulations, as well as their interactions, constitute a striking example of the continuous interplay among theory, observations and, more recently, model simulations. The atmosphere and ocean surface circulations were observed and analysed globally as early as the 16th and 17th centuries, in close association with the development of worldwide trade based on sailing. These efforts led to a number of important conceptual and theoretical works. For example, Edmund Halley first published a description of the tropical atmospheric cells in 1686, and George Hadley proposed a theory linking the existence of the trade winds with those cells in 1735. These early studies helped to forge concepts that are still useful in analysing and understanding both the atmospheric general circulation itself and model simulations (Lorenz, 1967; Holton, 1992).

A comprehensive description of these circulations was delayed by the lack of necessary observations in the higher atmosphere or deeper ocean. The balloon record of Gay-Lussac, who reached an altitude of 7,016 m in 1804, remained unbroken for more than 50 years. The stratosphere was independently discovered near the turn of the 20th century by Aßmann (1902) and Teisserenc de Bort (1902), and the first manned balloon flight into the stratosphere was made in 1901 (Berson and Süring, 1901). Even though it was recognised over 200 years ago (Rumford, 1800; see also Warren, 1981) that the oceans' cold subsurface waters must originate at high latitudes, it was not appreciated until the 20th century that the strength of the deep circulation might vary over time, or that the ocean's Meridional Overturning Circulation (MOC; often loosely referred to as the 'thermohaline circulation', see the Glossary for more information) may be very important for Earth's climate.

By the 1950s, studies of deep-sea cores suggested that the deep ocean temperatures had varied in the distant past. Technology also evolved to enable measurements that could confirm that the deep ocean is not only not static, but in fact quite dynamic (Swallow and Stommel's 1960 subsurface float experiment Aries, referred to by Crease, 1962). By the late 1970s, current meters could monitor deep currents for substantial amounts of time, and the first ocean observing satellite (SeaSat) revealed that significant information about subsurface ocean variability is imprinted on the sea surface. At the same time, the first estimates of the strength of the meridional transport of heat and mass were made (Oort and Vonder Haar, 1976; Wunsch, 1978), using a combination of models and data. Since then the technological developments have accelerated, but monitoring the MOC directly remains a substantial challenge (see Chapter 5), and routine observations of the subsurface ocean remain scarce compared to that of the atmosphere.

In parallel with the technological developments yielding new insights through observations, theoretical and numerical explorations of multiple (stable or unstable) equilibria began. Chamberlain (1906) suggested that deep ocean currents could reverse in direction, and might affect climate. The idea did not gain momentum until fifty years later, when Stommel (1961) presented a mechanism, based on the opposing effects that temperature and salinity have on density, by which ocean circulation can fluctuate between states. Numerical climate models incorporating models of the ocean circulation were developed during this period, including the pioneering work of Bryan (1969) and Manabe and Bryan (1969). The idea that the ocean circulation could change radically, and might perhaps even feel the attraction of different equilibrium states, gained further support through the simulations of coupled climate models (Bryan and Spelman, 1985; Bryan, 1986; Manabe and Stouffer, 1988). Model simulations using a hierarchy of models showed that the ocean circulation system appeared to be particularly vulnerable to changes in the freshwater balance, either by direct addition of freshwater or by changes in the hydrological cycle. A strong case emerged for the hypothesis that rapid changes in the Atlantic meridional circulation were responsible for the abrupt Dansgaard-Oeschger climate change events.

Although scientists now better appreciate the strength and variability of the global-scale ocean circulation, its roles in climate are still hotly debated. Is it a passive recipient of atmospheric forcing and so merely a diagnostic consequence of climate change, or is it an active contributor? Observational evidence for the latter proposition was presented by Sutton and Allen (1997), who noticed SST anomalies propagating along the Gulf Stream/North Atlantic Current system for years, and therefore implicated internal oceanic time scales. Is a radical change in the MOC likely in the near future? Brewer et al. (1983) and Lazier (1995) showed that the water masses of the North Atlantic were indeed changing (some becoming significantly fresher) in the modern observational record, a phenomenon that at least raises the possibility that ocean conditions may be approaching the point where the circulation might shift into Stommel's other stable regime. Recent developments in the ocean's various roles in climate can be found in Chapters 5, 6, 9 and 10.

Studying the interactions between atmosphere and ocean circulations was also facilitated through continuous interactions between observations, theories and simulations, as is dramatically illustrated by the century-long history of the advances in understanding the El Niño-Southern Oscillation (ENSO) phenomenon. This coupled air-sea phenomenon originates in the Pacific but affects climate globally, and has raised concern since at least the 19th century. Sir Gilbert Walker (1928) describes how H. H. Hildebrandsson (1897) noted large-scale relationships between interannual trends in pressure data from a worldwide network of 68 weather stations, and how Lockyer and Lockyer (1902) confirmed Hildebrandsson's discovery of an apparent 'seesaw' in pressure between South America and the Indonesian region. Walker named this seesaw pattern the 'Southern Oscillation' and related it to occurrences of drought and heavy rains in India, Australia, Indonesia and Africa. He also proposed that there must be a certain level of predictive skill in that system.

El Niño is the name given to the rather unusual oceanic conditions involving anomalously warm waters occurring in the eastern tropical Pacific off the coast of Peru every few years. The 1957–1958 International Geophysical Year coincided with a large El Niño, allowing a remarkable set of observations of the phenomenon. A decade later, a mechanism was presented that connected Walker's observations to El Niño (Bjerknes, 1969). This mechanism involved the interaction, through the SST field, between the east-west atmospheric circulation of which Walker's Southern Oscillation was an indicator (Bjerknes appropriately referred to this as the 'Walker Circulation') and variability in the pool of equatorial warm water of the Pacific Ocean. Observations made in the 1970s (e.g., Wyrtki, 1975) showed that prior to ENSO warm phases, the sea level in the western Pacific often rises significantly. By the mid-1980s, after an unusually disruptive El Niño struck in 1982 and 1983, an observing system (the Tropical Ocean Global Atmosphere (TOGA) array; see McPhaden et al., 1998) had been put in place to monitor ENSO. The resulting data confirmed the idea that the phenomenon was inherently one involving coupled atmosphere-ocean interactions and yielded much-needed detailed observational insights. By 1986, the first experimental ENSO forecasts were made (Cane et al., 1986; Zebiak and Cane, 1987).

The mechanisms and predictive skill of ENSO are still under discussion. In particular, it is not clear how ENSO changes with, and perhaps interacts with, a changing climate. The TAR states '...increasing evidence suggests the ENSO plays a fundamental role in global climate and its interannual variability, and increased credibility in both regional and global climate projections will be gained once realistic ENSOs and their changes are simulated'.

Just as the phenomenon of El Niño has been familiar to the people of tropical South America for centuries, a spatial pattern affecting climate variability in the North Atlantic has similarly been known by the people of Northern Europe for a long time. The Danish missionary Hans Egede made the following well-known diary entry in the mid-18th century: 'In Greenland, all winters are severe, yet they are not alike. The Danes have noticed that when the winter in Denmark was severe, as we perceive it, the winter in Greenland in its manner was mild, and conversely' (van Loon and Rogers, 1978).

Teisserenc de Bort, Hann, Exner, Defant and Walker all contributed to the discovery of the underlying dynamic structure. Walker, in his studies in the Indian Ocean, actually studied global maps of sea level pressure correlations, and named not only the Southern Oscillation, but also a Northern Oscillation, which he subsequently divided into a North Pacific and a North Atlantic Oscillation (Walker, 1924). However, it was Exner (1913, 1924) who made the first correlation maps showing the spatial structure in the NH, where the North Atlantic Oscillation (NAO) pattern stands out clearly as a north-south oscillation in atmospheric mass with centres of action near Iceland and Portugal.

The NAO significantly affects weather and climate, ecosystems and human activities of the North Atlantic sector. But what is the underlying mechanism? The recognition that the NAO is associated with variability and latitudinal shifts in the westerly flow of the jet stream originates with the works of Willett, Namias, Lorenz, Rossby and others in the 1930s, 1940s and 1950s (reviewed by Stephenson et al., 2003). Because atmospheric planetary waves are hemispheric in nature, changes in one region are often connected with changes in other regions, a phenomenon dubbed 'teleconnection' (Wallace and Gutzler, 1981).

The NAO may be partly described as a high-frequency stochastic process internal to the atmosphere. This understanding is evidenced by numerous atmosphere-only model simulations. It is also considered an expression of one of Earth's 'annular modes' (See Chapter 3). It is, however, the low-frequency variability of this phenomenon (Hurrell, 1995) that fuels continued investigations by climate scientists. The long time scales are the indication of potential predictive skill in the NAO. The mechanisms responsible for the correspondingly long 'memory' are still debated, although they are likely to have a local or remote oceanic origin. Bjerknes (1964) recognised the connection between the NAO index (which he referred to as the 'zonal index') and sea surface conditions. He speculated that ocean heat advection could play a role on longer time scales. The circulation of the Atlantic Ocean is radically different from that of the Indian and Pacific Oceans, in that the MOC is strongest in the Atlantic with warm water flowing northwards, even south of the equator, and cold water returning at depth. It would therefore not be surprising if the oceanic contributions to the NAO and to the Southern Oscillation were different.

Earth's climate is characterised by many modes of variability, involving both the atmosphere and ocean, and also the cryosphere and biosphere. Understanding the physical processes involved in producing low-frequency variability is crucial for improving scientists' ability to accurately predict climate change and for allowing the separation of anthropogenic and natural variability, thereby improving the ability to detect and attribute anthropogenic climate change. One central question for climate scientists, addressed in particular in Chapter 9, is to determine how human activities influence the dynamic nature of Earth's climate, and to identify what would have happened without any human influence at all.

1.5 Examples of Progress in Modelling the Climate

1.5.1 Model Evolution and Model Hierarchies

Climate scenarios rely upon the use of numerical models. The continuous evolution of these models over recent decades has been enabled by a considerable increase in computational capacity, with supercomputer speeds increasing by roughly a factor of a million in the three decades from the 1970s to the present. This computational progress has permitted a corresponding increase in model complexity (by including more and more components and processes, as depicted in Figure 1.2), in the length of the simulations, and in spatial resolution, as shown in Figure 1.4. The models used to evaluate future climate changes have therefore evolved over time. Most of the pioneering work on CO_2-induced climate change was based on atmospheric general circulation models coupled to simple 'slab' ocean models (i.e., models omitting ocean dynamics), from the early work of Manabe and Wetherald (1975) to the review of Schlesinger and Mitchell (1987). At the same time the physical content of the models has become more comprehensive (see in Section 1.5.2 the example of clouds). Similarly, most of the results presented in the FAR were from atmospheric models, rather than from models of the coupled climate system, and were used to analyse changes in the equilibrium climate resulting from a doubling of the atmospheric CO_2 concentration. Current climate projections can investigate time-dependent scenarios of climate evolution and can make use of much more complex coupled ocean-atmosphere models, sometimes even including interactive chemical or biochemical components.

A parallel evolution toward increased complexity and resolution has occurred in the domain of numerical weather prediction, and has resulted in a large and verifiable improvement in operational weather forecast quality. This example alone shows that present models are more realistic than were those of a decade ago. There is also, however, a continuing awareness that models do not provide a perfect simulation of reality, because resolving all important spatial or time scales remains far beyond current capabilities, and also because the behaviour of such a complex nonlinear system may in general be chaotic.

It has been known since the work of Lorenz (1963) that even simple models may display intricate behaviour because of their nonlinearities. The inherent nonlinear behaviour of the climate system appears in climate simulations at all time scales (Ghil, 1989). In fact, the study of nonlinear dynamical systems has become important for a wide range of scientific disciplines, and the corresponding mathematical developments are essential to interdisciplinary studies. Simple models of ocean-atmosphere interactions, climate-biosphere interactions or climate-economy interactions may exhibit a similar behaviour, characterised by partial unpredictability, bifurcations and transition to chaos.

In addition, many of the key processes that control climate sensitivity or abrupt climate changes (e.g., clouds, vegetation, oceanic convection) depend on very small spatial scales. They cannot be represented in full detail in the context of global models, and scientific understanding of them is still notably incomplete. Consequently, there is a continuing need to assist in the use and interpretation of complex models through models that are either conceptually simpler, or limited to a number of processes or to a specific region, therefore enabling a deeper understanding of the processes at work or a more relevant comparison with observations. With the development of computer capacities, simpler models have not disappeared; on the contrary, a stronger emphasis has been given to the concept of a 'hierarchy of models' as the only way to provide a linkage between theoretical understanding and the complexity of realistic models (Held, 2005).

The list of these 'simpler' models is very long. Simplicity may lie in the reduced number of equations (e.g., a single

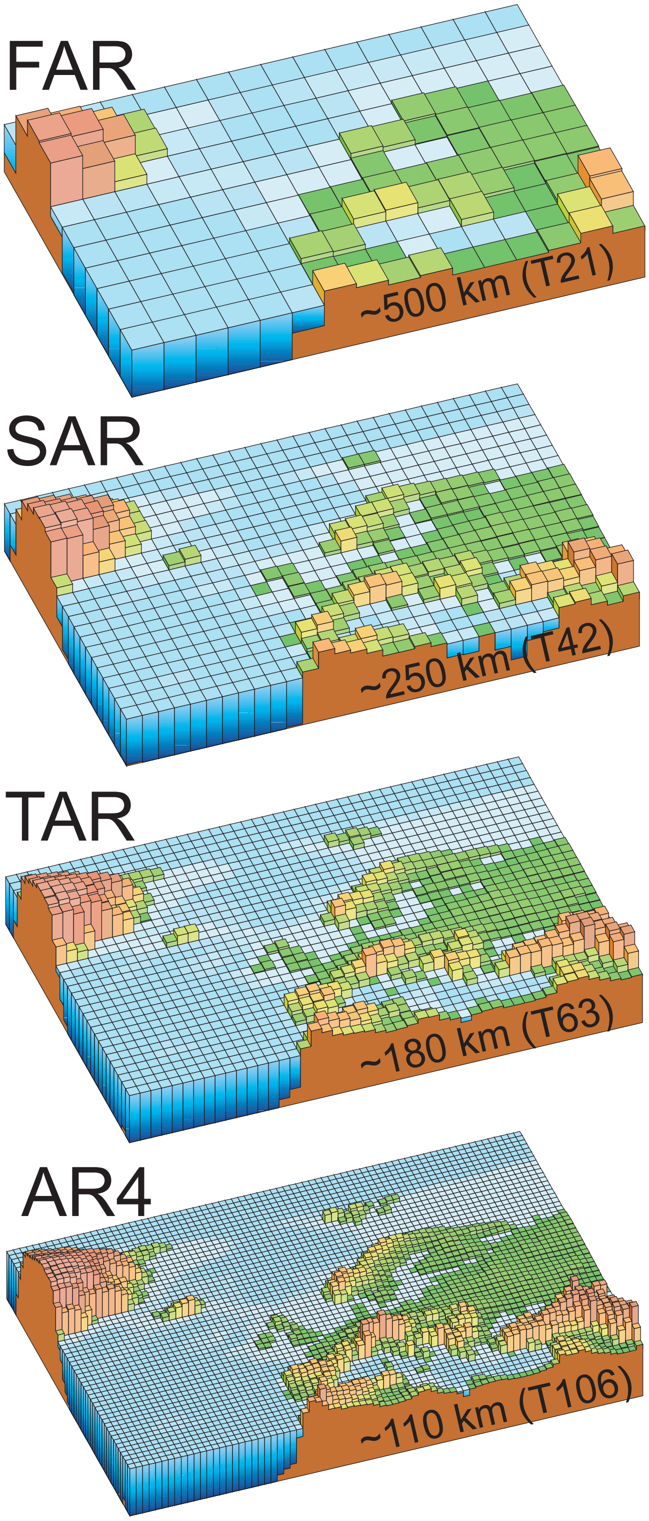


Figure 1.4. *Geographic resolution characteristic of the generations of climate models used in the IPCC Assessment Reports: FAR (IPCC, 1990), SAR (IPCC, 1996), TAR (IPCC, 2001a), and AR4 (2007). The figures above show how successive generations of these global models increasingly resolved northern Europe. These illustrations are representative of the most detailed horizontal resolution used for short-term climate simulations. The century-long simulations cited in IPCC Assessment Reports after the FAR were typically run with the previous generation's resolution. Vertical resolution in both atmosphere and ocean models is not shown, but it has increased comparably with the horizontal resolution, beginning typically with a single-layer slab ocean and ten atmospheric layers in the FAR and progressing to about thirty levels in both atmosphere and ocean.*

equation for the global surface temperature); in the reduced dimensionality of the problem (one-dimension vertical, one-dimension latitudinal, two-dimension); or in the restriction to a few processes (e.g., a mid-latitude quasi-geostrophic atmosphere with or without the inclusion of moist processes). The notion of model hierarchy is also linked to the idea of scale: global circulation models are complemented by regional models that exhibit a higher resolution over a given area, or process oriented models, such as cloud resolving models or large eddy simulations. Earth Models of Intermediate Complexity are used to investigate long time scales, such as those corresponding to glacial to interglacial oscillations (Berger et al., 1998). This distinction between models according to scale is evolving quickly, driven by the increase in computer capacities. For example, global models explicitly resolving the dynamics of convective clouds may soon become computationally feasible.

Many important scientific debates in recent years have had their origin in the use of conceptually simple models. The study of idealised atmospheric representations of the tropical climate, for example by Pierrehumbert (1995) who introduced a separate representation of the areas with ascending and subsiding circulation in the tropics, has significantly improved the understanding of the feedbacks that control climate. Simple linearized models of the atmospheric circulation have been used to investigate potential new feedback effects. Ocean box models have played an important role in improving the understanding of the possible slowing down of the Atlantic thermohaline circulation (Birchfield et al., 1990), as emphasized in the TAR. Simple models have also played a central role in the interpretation of IPCC scenarios: the investigation of climate scenarios presented in the SAR or the TAR has been extended to larger ensembles of cases using idealised models.

1.5.2 Model Clouds and Climate Sensitivity

The modelling of cloud processes and feedbacks provides a striking example of the irregular pace of progress in climate science. Representation of clouds may constitute the area in which atmospheric models have been modified most continuously to take into account increasingly complex physical processes. At the time of the TAR clouds remained a major source of uncertainty in the simulation of climate changes (as they still are at present: e.g., Sections 2.4, 2.6, 3.4.3, 7.5, 8.2, 8.4.11, 8.6.2.2, 8.6.3.2, 9.2.1.2, 9.4.1.8, 10.2.1.2, 10.3.2.2, 10.5.4.3, 11.8.1.3, 11.8.2.2).

In the early 1980s, most models were still using prescribed cloud amounts, as functions of location and altitude, and prescribed cloud radiative properties, to compute atmospheric radiation. The cloud amounts were very often derived from the zonally averaged climatology of London (1957). Succeeding generations of models have used relative humidity or other simple predictors to diagnose cloudiness (Slingo, 1987), thus providing a foundation of increased realism for the models, but at the same time possibly causing inconsistencies in the representation of the multiple roles of clouds as bodies interacting with radiation, generating precipitation and influencing small-scale convective or turbulent circulations. Following the pioneering studies of Sundqvist (1978), an explicit representation of clouds was progressively introduced into climate models, beginning in the late 1980s. Models first used simplified representations of cloud microphysics, following, for example, Kessler (1969), but more recent generations of models generally incorporate a much more comprehensive and detailed representation of clouds, based on consistent physical principles. Comparisons of model results with observational data presented in the TAR have shown that, based on zonal averages, the representation of clouds in most climate models was also more realistic in 2000 than had been the case only a few years before.

In spite of this undeniable progress, the amplitude and even the sign of cloud feedbacks was noted in the TAR as highly uncertain, and this uncertainty was cited as one of the key factors explaining the spread in model simulations of future climate for a given emission scenario. This cannot be regarded as a surprise: that the sensitivity of the Earth's climate to changing atmospheric greenhouse gas concentrations must depend strongly on cloud feedbacks can be illustrated on the simplest theoretical grounds, using data that have been available for a long time. Satellite measurements have indeed provided meaningful estimates of Earth's radiation budget since the early 1970s (Vonder Haar and Suomi, 1971). Clouds, which cover about 60% of the Earth's surface, are responsible for up to two-thirds of the planetary albedo, which is about 30%. An albedo decrease of only 1%, bringing the Earth's albedo from 30% to 29%, would cause an increase in the black-body radiative equilibrium temperature of about 1°C, a highly significant value, roughly equivalent to the direct radiative effect of a doubling of the atmospheric CO_2 concentration. Simultaneously, clouds make an important contribution to the planetary greenhouse effect. In addition, changes in cloud cover constitute only one of the many parameters that affect cloud radiative interactions: cloud optical thickness, cloud height and cloud microphysical properties can also be modified by atmospheric temperature changes, which adds to the complexity of feedbacks, as evidenced, for example, through satellite observations analysed by Tselioudis and Rossow (1994).

The importance of simulated cloud feedbacks was revealed by the analysis of model results (Manabe and Wetherald, 1975; Hansen et al, 1984), and the first extensive model intercomparisons (Cess et al., 1989) also showed a substantial model dependency. The strong effect of cloud processes on climate model sensitivities to greenhouse gases was emphasized further through a now-classic set of General Circulation Model (GCM) experiments, carried out by Senior and Mitchell (1993). They produced global average surface temperature changes (due to doubled atmospheric CO_2 concentration) ranging from 1.9°C to 5.4°C, simply by altering the way that cloud radiative properties were treated in the model. It is somewhat unsettling that the results of a complex climate model can be so drastically altered by substituting one reasonable cloud parametrization for another, thereby approximately replicating the overall inter-model range of sensitivities. Other GCM groups have also

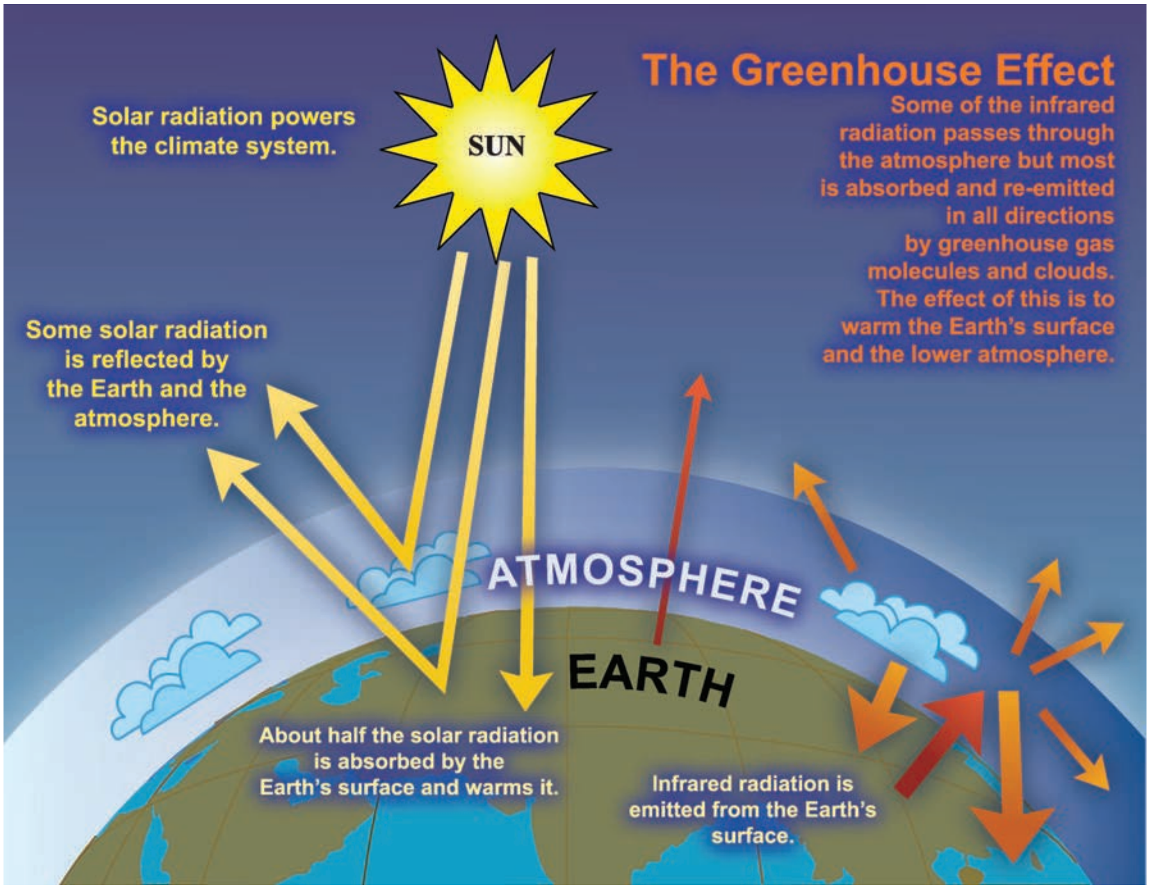
Frequently Asked Question 1.3

What is the Greenhouse Effect?

The Sun powers Earth's climate, radiating energy at very short wavelengths, predominately in the visible or near-visible (e.g., ultraviolet) part of the spectrum. Roughly one-third of the solar energy that reaches the top of Earth's atmosphere is reflected directly back to space. The remaining two-thirds is absorbed by the surface and, to a lesser extent, by the atmosphere. To balance the absorbed incoming energy, the Earth must, on average, radiate the same amount of energy back to space. Because the Earth is much colder than the Sun, it radiates at much longer wavelengths, primarily in the infrared part of the spectrum (see Figure 1). Much of this thermal radiation emitted by the land and ocean is absorbed by the atmosphere, including clouds, and reradiated back to Earth. This is called the greenhouse effect. The glass walls in a greenhouse reduce airflow and increase the temperature of the air inside. Analogously, but through a different physical process, the Earth's greenhouse effect warms the surface of the planet. Without the natural greenhouse effect, the average temperature at Earth's surface would be below the freezing point of water. Thus, Earth's natural greenhouse effect makes life as we know it possible. However, human activities, primarily the burning of fossil fuels and clearing of forests, have greatly intensified the natural greenhouse effect, causing global warming.

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapour is the most important greenhouse gas, and carbon dioxide (CO_2) is the second-most important one. Methane, nitrous oxide, ozone and several other gases present in the atmosphere in small amounts also contribute to the greenhouse effect. In the humid equatorial regions, where there is so much water vapour in the air that the greenhouse effect is very large, adding a small additional amount of CO_2 or water vapour has only a small direct impact on downward infrared radiation. However, in the cold, dry polar regions, the effect of a small increase in CO_2 or

(continued)



FAQ 1.3, Figure 1. *An idealised model of the natural greenhouse effect. See text for explanation.*

water vapour is much greater. The same is true for the cold, dry upper atmosphere where a small increase in water vapour has a greater influence on the greenhouse effect than the same change in water vapour would have near the surface.

Several components of the climate system, notably the oceans and living things, affect atmospheric concentrations of greenhouse gases. A prime example of this is plants taking CO_2 out of the atmosphere and converting it (and water) into carbohydrates via photosynthesis. In the industrial era, human activities have added greenhouse gases to the atmosphere, primarily through the burning of fossil fuels and clearing of forests.

Adding more of a greenhouse gas, such as CO_2, to the atmosphere intensifies the greenhouse effect, thus warming Earth's climate. The amount of warming depends on various feedback mechanisms. For example, as the atmosphere warms due to rising levels of greenhouse gases, its concentration of water vapour increases, further intensifying the greenhouse effect. This in turn causes more warming, which causes an additional increase in water vapour, in a self-reinforcing cycle. This water vapour feedback may be strong enough to approximately double the increase in the greenhouse effect due to the added CO_2 alone.

Additional important feedback mechanisms involve clouds. Clouds are effective at absorbing infrared radiation and therefore exert a large greenhouse effect, thus warming the Earth. Clouds are also effective at reflecting away incoming solar radiation, thus cooling the Earth. A change in almost any aspect of clouds, such as their type, location, water content, cloud altitude, particle size and shape, or lifetimes, affects the degree to which clouds warm or cool the Earth. Some changes amplify warming while others diminish it. Much research is in progress to better understand how clouds change in response to climate warming, and how these changes affect climate through various feedback mechanisms.

consistently obtained widely varying results by trying other techniques of incorporating cloud microphysical processes and their radiative interactions (e.g., Roeckner et al., 1987; Le Treut and Li, 1991), which differed from the approach of Senior and Mitchell (1993) through the treatment of partial cloudiness or mixed-phase properties. The model intercomparisons presented in the TAR showed no clear resolution of this unsatisfactory situation.

The scientific community realised long ago that using adequate data to constrain models was the only way to solve this problem. Using climate changes in the distant past to constrain the amplitude of cloud feedback has definite limitations (Ramstein et al., 1998). The study of cloud changes at decadal, interannual or seasonal time scales therefore remains a necessary path to constrain models. A long history of cloud observations now runs parallel to that of model development. Operational ground-based measurements, carried out for the purpose of weather prediction, constitute a valuable source of information that has been gathered and analysed by Warren et al. (1986, 1988). The International Satellite Cloud Climatology Project (ISCCP; Rossow and Schiffer, 1991) has developed an analysis of cloud cover and cloud properties using the measurements of operational meteorological satellites over a period of more than two decades. These data have been complemented by other satellite remote sensing data sets, such as those associated with the Nimbus-7 Temperature Humidity Infrared Radiometer (THIR) instrument (Stowe et al., 1988), with high-resolution spectrometers such as the High Resolution Infrared Radiation Sounder (HIRS) (Susskind et al., 1987), and with microwave absorption, as used by the Special Sensor Microwave/Imager (SSM/I). Chapter 8 provides an update of this ongoing observational effort.

A parallel effort has been carried out to develop a wider range of ground-based measurements, not only to provide an adequate reference for satellite observations, but also to make possible a detailed and empirically based analysis of the entire range of space and time scales involved in cloud processes. The longest-lasting and most comprehensive effort has been the Atmospheric Radiation Measurement (ARM) Program in the USA, which has established elaborately instrumented observational sites to monitor the full complexity of cloud systems on a long-term basis (Ackerman and Stokes, 2003). Shorter field campaigns dedicated to the observation of specific phenomena have also been established, such as the TOGA Coupled Ocean-Atmosphere Response Experiment (COARE) for convective systems (Webster and Lukas, 1992), or the Atlantic Stratocumulus Transition Experiment (ASTEX) for stratocumulus (Albrecht et al., 1995).

Observational data have clearly helped the development of models. The ISCCP data have greatly aided the development of cloud representations in climate models since the mid-1980s (e.g., Le Treut and Li, 1988; Del Genio et al., 1996). However, existing data have not yet brought about any reduction in the existing range of simulated cloud feedbacks. More recently, new theoretical tools have been developed to aid in validating parametrizations in a mode that emphasizes the role of cloud processes participating in climatic feedbacks. One such approach has been to focus on comprehensively observed episodes of cloudiness for which the large-scale forcing is observationally known, using single-column models (Randall et al., 1996; Somerville, 2000) and higher-resolution cloud-resolving models to evaluate GCM parametrizations. Another approach is to make use of the more global and continuous satellite data, on a statistical basis, through an investigation of the correlation between climate forcing and cloud parameters (Bony et al., 1997), in such a way as to provide a test of feedbacks between different climate variables. Chapter 8 assesses recent progress in this area.

1.5.3 Coupled Models: Evolution, Use, Assessment

The first National Academy of Sciences of the USA report on global warming (Charney et al., 1979), on the basis of two models simulating the impact of doubled atmospheric CO_2 concentrations, spoke of a range of global mean equilibrium surface temperature increase of between 1.5°C and 4.5°C, a range that has remained part of conventional wisdom at least as recently as the TAR. These climate projections, as well as those treated later in the comparison of three models by Schlesinger and Mitchell (1987) and most of those presented in the FAR, were the results of atmospheric models coupled with simple 'slab' ocean models (i.e., models omitting all changes in ocean dynamics).

The first attempts at coupling atmospheric and oceanic models were carried out during the late 1960s and early 1970s (Manabe and Bryan, 1969; Bryan et al., 1975; Manabe et al., 1975). Replacing 'slab' ocean models by fully coupled ocean-atmosphere models may arguably have constituted one of the most significant leaps forward in climate modelling during the last 20 years (Trenberth, 1993), although both the atmospheric and oceanic components themselves have undergone highly significant improvements. This advance has led to significant modifications in the patterns of simulated climate change, particularly in oceanic regions. It has also opened up the possibility of exploring transient climate scenarios, and it constitutes a step toward the development of comprehensive 'Earth-system models' that include explicit representations of chemical and biogeochemical cycles.

Throughout their short history, coupled models have faced difficulties that have considerably impeded their development, including: (i) the initial state of the ocean is not precisely known; (ii) a surface flux imbalance (in either energy, momentum or fresh water) much smaller than the observational accuracy is enough to cause a drifting of coupled GCM simulations into unrealistic states; and (iii) there is no direct stabilising feedback that can compensate for any errors in the simulated salinity. The strong emphasis placed on the realism of the simulated base state provided a rationale for introducing 'flux adjustments' or 'flux corrections' (Manabe and Stouffer, 1988; Sausen et al., 1988) in early simulations. These were essentially empirical corrections that could not be justified on physical principles, and that consisted of arbitrary additions of surface fluxes of heat and salinity in order to prevent the drift of the simulated climate away from a realistic state. The National Center for Atmospheric Research model may have been the first to realise non-flux-corrected coupled simulations systematically, and it was able to achieve simulations of climate change into the 21st century, in spite of a persistent drift that still affected many of its early simulations. Both the FAR and the SAR pointed out the apparent need for flux adjustments as a problematic feature of climate modelling (Cubasch et al., 1990; Gates et al., 1996).

By the time of the TAR, however, the situation had evolved, and about half the coupled GCMs assessed in the TAR did not employ flux adjustments. That report noted that 'some non-flux-adjusted models are now able to maintain stable climatologies of comparable quality to flux-adjusted models' (McAvaney et al., 2001). Since that time, evolution away from flux correction (or flux adjustment) has continued at some modelling centres, although a number of state-of-the-art models continue to rely on it. The design of the coupled model simulations is also strongly linked with the methods chosen for model initialisation. In flux-adjusted models, the initial ocean state is necessarily the result of preliminary and typically thousand-year-long simulations to bring the ocean model into equilibrium. Non-flux-adjusted models often employ a simpler procedure based on ocean observations, such as those compiled by Levitus et al. (1994), although some spin-up phase is even then necessary. One argument brought forward is that non-adjusted models made use of *ad hoc* tuning of radiative parameters (i.e., an implicit flux adjustment).

This considerable advance in model design has not diminished the existence of a range of model results. This is not a surprise, however, because it is known that climate predictions are intrinsically affected by uncertainty (Lorenz, 1963). Two distinct kinds of prediction problems were defined by Lorenz (1975). The first kind was defined as the prediction of the actual properties of the climate system in response to a given initial state. Predictions of the first kind are initial-value problems and, because of the nonlinearity and instability of the governing equations, such systems are not predictable indefinitely into the future. Predictions of the second kind deal with the determination of the response of the climate system to changes in the external forcings. These predictions are not concerned directly with the chronological evolution of the climate state, but rather with the long-term average of the statistical properties of climate. Originally, it was thought that predictions of the second kind do not at all depend on initial conditions. Instead, they are intended to determine how the statistical properties of the climate system (e.g., the average annual global mean temperature, or the expected number of winter storms or hurricanes, or the average monsoon rainfall) change as some external forcing parameter, for example CO_2 content, is altered. Estimates of future climate scenarios as a function of the concentration of atmospheric greenhouse gases are typical examples of predictions of the second kind. However, ensemble simulations show that the projections tend to form clusters around a number of attractors as a function of their initial state (see Chapter 10).

Uncertainties in climate predictions (of the second kind) arise mainly from model uncertainties and errors. To assess and disentangle these effects, the scientific community has organised a series of systematic comparisons of the different existing models, and it has worked to achieve an increase in the number and range of simulations being carried out in order to more fully explore the factors affecting the accuracy of the simulations.

An early example of systematic comparison of models is provided by Cess et al. (1989), who compared results of documented differences among model simulations in their representation of cloud feedback to show how the consequent effects on atmospheric radiation resulted in different model response to doubling of the CO_2 concentration. A number of ambitious and comprehensive 'model intercomparison projects' (MIPs) were set up in the 1990s under the auspices of the World Climate Research Programme to undertake controlled conditions for model evaluation. One of the first was the Atmospheric Model Intercomparison Project (AMIP), which studied atmospheric GCMs. The development of coupled models induced the development of the Coupled Model Intercomparison Project (CMIP), which studied coupled ocean-atmosphere GCMs and their response to idealised forcings, such as a 1% yearly increase in the atmospheric CO_2 concentration. It proved important in carrying out the various MIPs to standardise the model forcing parameters and the model output so that file formats, variable names, units, etc., are easily recognised by data users. The fact that the model results were stored separately and independently of the modelling centres, and that the analysis of the model output was performed mainly by research groups independent of the modellers, has added confidence in the results. Summary diagnostic products such as the Taylor (2001) diagram were developed for MIPs.

The establishment of the AMIP and CMIP projects opened a new era for climate modelling, setting standards of quality control, providing organisational continuity and ensuring that results are generally reproducible. Results from AMIP have provided a number of insights into climate model behaviour (Gates et al., 1999) and quantified improved agreement between simulated and observed atmospheric properties as new versions of models are developed. In general, results of the MIPs suggest that the most problematic areas of coupled model simulations involve cloud-radiation processes, the cryosphere, the deep ocean and ocean-atmosphere interactions.

Comparing different models is not sufficient, however. Using multiple simulations from a single model (the so-called Monte Carlo, or ensemble, approach) has proved a necessary and complementary approach to assess the stochastic nature of the climate system. The first ensemble climate change simulations with global GCMs used a set of different initial and boundary conditions (Cubasch et al., 1994; Barnett, 1995). Computational constraints limited early ensembles to a relatively small number of samples (fewer than 10). These ensemble simulations clearly indicated that even with a single model a large spread in the climate projections can be obtained.

Intercomparison of existing models and ensemble model studies (i.e., those involving many integrations of the same model) are still undergoing rapid development. Running ensembles was essentially impossible until recent advances in computer power occurred, as these systematic comprehensive climate model studies are exceptionally demanding on computer resources. Their progress has marked the evolution from the FAR to the TAR, and is likely to continue in the years to come.

1.6 The IPCC Assessments of Climate Change and Uncertainties

The WMO and the United Nations Environment Programme (UNEP) established the IPCC in 1988 with the assigned role of assessing the scientific, technical and socioeconomic information relevant for understanding the risk of human-induced climate change. The original 1988 mandate for the IPCC was extensive: '(a) Identification of uncertainties and gaps in our present knowledge with regard to climate changes and its potential impacts, and preparation of a plan of action over the short-term in filling these gaps; (b) Identification of information needed to evaluate policy implications of climate change and response strategies; (c) Review of current and planned national/international policies related to the greenhouse gas issue; (d) Scientific and environmental assessments of all aspects of the greenhouse gas issue and the transfer of these assessments and other relevant information to governments and intergovernmental organisations to be taken into account in their policies on social and economic development and environmental programs.' The IPCC is open to all members of UNEP and WMO. It does not directly support new research or monitor climate-related data. However, the IPCC process of synthesis and assessment has often inspired scientific research leading to new findings.

The IPCC has three Working Groups and a Task Force. Working Group I (WGI) assesses the scientific aspects of the climate system and climate change, while Working Groups II (WGII) and III (WGIII) assess the vulnerability and adaptation of socioeconomic and natural systems to climate change, and the mitigation options for limiting greenhouse gas emissions, respectively. The Task Force is responsible for the IPCC National Greenhouse Gas Inventories Programme. This brief history focuses on WGI and how it has described uncertainty in the quantities presented (See Box 1.1).

A main activity of the IPCC is to provide on a regular basis an assessment of the state of knowledge on climate change, and this volume is the fourth such Assessment Report of WGI. The IPCC also prepares Special Reports and Technical Papers on topics for which independent scientific information and advice is deemed necessary, and it supports the United Nations Framework Convention on Climate Change (UNFCCC) through its work on methodologies for National Greenhouse Gas Inventories. The FAR played an important role in the discussions of the Intergovernmental Negotiating Committee for the UNFCCC. The UNFCCC was adopted in 1992 and entered into force in 1994. It provides the overall policy framework and legal basis for addressing the climate change issue.

The WGI FAR was completed under the leadership of Bert Bolin (IPCC Chair) and John Houghton (WGI Chair) in a plenary at Windsor, UK in May 1990. In a mere 365 pages with eight colour plates, it made a persuasive, but not quantitative, case for anthropogenic interference with the climate system. Most conclusions from the FAR were non-quantitative and remain valid today (see also Section 1.4.4). For example, in terms of the greenhouse gases, 'emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases: CO_2, CH_4, CFCs, N_2O' (see Chapters 2 and 3; Section 7.1). On the other hand, the FAR did not foresee the phase-out of CFCs, missed the importance of biomass-burning aerosols and dust to climate and stated that unequivocal detection of the enhanced greenhouse effect was more than a decade away. The latter two areas highlight the advance of climate science and in particular the merging of models and observations in the new field of detection and attribution (see Section 9.1).

The Policymakers Summary of the WGI FAR gave a broad overview of climate change science and its Executive Summary separated key findings into areas of varying levels of confidence ranging from 'certainty' to providing an expert 'judgment'. Much of the summary is not quantitative (e.g., the radiative forcing bar charts do not appear in the summary). Similarly, scientific uncertainty is hardly mentioned; when ranges are given, as in the projected temperature increases of 0.2°C to 0.5°C per decade, no probability or likelihood is assigned to explain the range (see Chapter 10). In discussion of the climate sensitivity to doubled atmospheric CO_2 concentration, the combined subjective and objective criteria are explained: the range of model results was 1.9°C to 5.2°C; most were close to 4.0°C; but the newer model results were lower; and hence the best estimate was 2.5°C with a range of 1.5°C to 4.5°C. The likelihood of the value being within this range was not defined. However, the importance of identifying those areas where climate scientists had high confidence was recognised in the Policymakers Summary.

The Supplementary Report (IPCC, 1992) re-evaluated the RF values of the FAR and included the new IPCC scenarios for future emissions, designated IS92a–f. It also included updated chapters on climate observations and modelling (see Chapters 3, 4, 5, 6 and 8). The treatment of scientific uncertainty remained as in the FAR. For example, the calculated increase in global mean surface temperature since the 19th century was given as 0.45°C ± 0.15°C, with no quantitative likelihood for this range (see Section 3.2).

The SAR, under Bert Bolin (IPCC Chair) and John Houghton and Gylvan Meira Filho (WGI Co-chairs), was planned with and coupled to a preliminary Special Report (IPCC, 1995) that contained intensive chapters on the carbon cycle, atmospheric chemistry, aerosols and radiative forcing. The WGI SAR culminated in the government plenary in Madrid in November 1995. The most cited finding from that plenary, on attribution of climate change, has been consistently reaffirmed by subsequent research: 'The balance of evidence suggests a discernible human influence on global climate' (see Chapter 9). The SAR provided key input to the negotiations that led to the adoption in 1997 of the Kyoto Protocol to the UNFCCC.

Uncertainty in the WGI SAR was defined in a number of ways. The carbon cycle budgets used symmetric plus/minus ranges explicitly defined as 90% confidence intervals, whereas the RF bar chart reported a 'mid-range' bar along with a plus/minus range that was estimated largely on the spread of published values. The likelihood, or confidence interval, of the spread of published results was not given. These uncertainties were additionally modified by a declaration that the confidence of the RF being within the specified range was indicated by a stated confidence level that ranged from 'high' (greenhouse gases) to 'very low' (aerosols). Due to the difficulty in approving such a long draft in plenary, the Summary for Policy Makers (SPM) became a short document with no figures and few numbers. The use of scientific uncertainty in the SPM was thus limited and similar to the FAR: a range in the mean surface temperature increase since 1900 was given as 0.3°C to 0.6°C with no explanation as to likelihood of this range. While the underlying report showed projected future warming for a range of different climate models, the Technical Summary focused on a central estimate.

The IPCC Special Report on Aviation and the Global Atmosphere (IPCC, 1999) was a major interim assessment involving both WGI and WGIII and the Scientific Assessment Panel to the Montreal Protocol on Substances that Deplete the Ozone Layer. It assessed the impacts of civil aviation in terms of climate change and global air quality as well as looking at the effect of technology options for the future fleet. It was the first complete assessment of an industrial sub-sector. The summary related aviation's role relative to all human influence on the climate system: 'The best estimate of the radiative forcing in 1992 by aircraft is 0.05 W m^{-2} or about 3.5% of the total radiative forcing by all anthropogenic activities.' The authors took a uniform approach to assigning and propagating uncertainty in these RF values based on mixed objective and subjective criteria. In addition to a best value, a two-thirds likelihood (67% confidence) interval is given. This interval is similar to a one-sigma (i.e., one standard deviation) normal error distribution, but it was explicitly noted that the probability distribution outside this interval was not evaluated and might not have a normal distribution. A bar chart with 'whiskers' (two-thirds likelihood range) showing the components and total (without cirrus effects) RF for aviation in 1992 appeared in the SPM (see Sections 2.6 and 10.2).

The TAR, under Robert Watson (IPCC Chair) and John Houghton and Ding YiHui (WGI Co-chairs), was approved at the government plenary in Shanghai in January 2001. The predominant summary statements from the TAR WGI strengthened the SAR's attribution statement: 'An increasing body of observations gives a collective picture of a warming world and other changes in the climate system', and 'There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities.' The TAR Synthesis Report (IPCC, 2001b) combined the assessment reports from the three Working Groups. By combining data on global (WGI) and regional (WGII) climate change, the Synthesis Report was able to strengthen the conclusion regarding human influence: 'The Earth's climate system has demonstrably changed on both global and regional scales since the pre-industrial era, with some of these changes attributable to human activities' (see Chapter 9).

Box 1.1: Treatment of Uncertainties in the Working Group I Assessment

The importance of consistent and transparent treatment of uncertainties is clearly recognised by the IPCC in preparing its assessments of climate change. The increasing attention given to formal treatments of uncertainty in previous assessments is addressed in Section 1.6. To promote consistency in the general treatment of uncertainty across all three Working Groups, authors of the Fourth Assessment Report have been asked to follow a brief set of guidance notes on determining and describing uncertainties in the context of an assessment .[1] This box summarises the way that Working Group I has applied those guidelines and covers some aspects of the treatment of uncertainty specific to material assessed here.

Uncertainties can be classified in several different ways according to their origin. Two primary types are 'value uncertainties' and 'structural uncertainties'. Value uncertainties arise from the incomplete determination of particular values or results, for example, when data are inaccurate or not fully representative of the phenomenon of interest. Structural uncertainties arise from an incomplete understanding of the processes that control particular values or results, for example, when the conceptual framework or model used for analysis does not include all the relevant processes or relationships. Value uncertainties are generally estimated using statistical techniques and expressed probabilistically. Structural uncertainties are generally described by giving the authors' collective judgment of their confidence in the correctness of a result. In both cases, estimating uncertainties is intrinsically about describing the limits to knowledge and for this reason involves expert judgment about the state of that knowledge. A different type of uncertainty arises in systems that are either chaotic or not fully deterministic in nature and this also limits our ability to project all aspects of climate change.

The scientific literature assessed here uses a variety of other generic ways of categorising uncertainties. Uncertainties associated with 'random errors' have the characteristic of decreasing as additional measurements are accumulated, whereas those associated with 'systematic errors' do not. In dealing with climate records, considerable attention has been given to the identification of systematic errors or unintended biases arising from data sampling issues and methods of analysing and combining data. Specialised statistical methods based on quantitative analysis have been developed for the detection and attribution of climate change and for producing probabilistic projections of future climate parameters. These are summarised in the relevant chapters.

The uncertainty guidance provided for the Fourth Assessment Report draws, for the first time, a careful distinction between levels of confidence in scientific understanding and the likelihoods of specific results. This allows authors to express high confidence that an event is extremely unlikely (e.g., rolling a dice twice and getting a six both times), as well as high confidence that an event is about as likely as not (e.g., a tossed coin coming up heads). Confidence and likelihood as used here are distinct concepts but are often linked in practice.

The standard terms used to define levels of confidence in this report are as given in the IPCC Uncertainty Guidance Note, namely:

Confidence Terminology	**Degree of confidence in being correct**
Very high confidence	At least 9 out of 10 chance
High confidence	About 8 out of 10 chance
Medium confidence	About 5 out of 10 chance
Low confidence	About 2 out of 10 chance
Very low confidence	Less than 1 out of 10 chance

Note that 'low confidence' and 'very low confidence' are only used for areas of major concern and where a risk-based perspective is justified.

Chapter 2 of this report uses a related term 'level of scientific understanding' when describing uncertainties in different contributions to radiative forcing. This terminology is used for consistency with the Third Assessment Report, and the basis on which the authors have determined particular levels of scientific understanding uses a combination of approaches consistent with the uncertainty guidance note as explained in detail in Section 2.9.2 and Table 2.11.

[1] See Supplementary Material for this report

The standard terms used in this report to define the likelihood of an outcome or result where this can be estimated probabilistically are:

Likelihood Terminology	**Likelihood of the occurrence/ outcome**
Virtually certain	> 99% probability
Extremely likely	> 95% probability
Very likely	> 90% probability
Likely	> 66% probability
More likely than not	> 50% probability
About as likely as not	33 to 66% probability
Unlikely	< 33% probability
Very unlikely	< 10% probability
Extremely unlikely	< 5% probability
Exceptionally unlikely	< 1% probability

The terms 'extremely likely', 'extremely unlikely' and 'more likely than not' as defined above have been added to those given in the IPCC Uncertainty Guidance Note in order to provide a more specific assessment of aspects including attribution and radiative forcing.

Unless noted otherwise, values given in this report are assessed best estimates and their uncertainty ranges are 90% confidence intervals (i.e., there is an estimated 5% likelihood of the value being below the lower end of the range or above the upper end of the range). Note that in some cases the nature of the constraints on a value, or other information available, may indicate an asymmetric distribution of the uncertainty range around a best estimate.

In an effort to promote consistency, a guidance paper on uncertainty (Moss and Schneider, 2000) was distributed to all Working Group authors during the drafting of the TAR. The WGI TAR made some effort at consistency, noting in the SPM that when ranges were given they generally denoted 95% confidence intervals, although the carbon budget uncertainties were specified as ±1 standard deviation (68% likelihood). The range of 1.5°C to 4.5°C for climate sensitivity to atmospheric CO_2 doubling was reiterated but with no confidence assigned; however, it was clear that the level of scientific understanding had increased since that same range was first given in the Charney et al. (1979) report. The RF bar chart noted that the RF components could not be summed (except for the long-lived greenhouse gases) and that the 'whiskers' on the RF bars each meant something different (e.g., some were the range of models, some were uncertainties). Another failure in dealing with uncertainty was the projection of 21st-century warming: it was reported as a range covering (i) six Special Report on Emission Scenarios (SRES) emissions scenarios and (ii) nine atmosphere-ocean climate models using two grey envelopes without estimates of likelihood levels. The full range (i.e., scenario plus climate model range) of 1.4°C to 5.8°C is a much-cited finding of the WGI TAR but the lack of discussion of associated likelihood in the report makes the interpretation and useful application of this result difficult.

1.7 Summary

As this chapter shows, the history of the centuries-long effort to document and understand climate change is often complex, marked by successes and failures, and has followed a very uneven pace. Testing scientific findings and openly discussing the test results have been the key to the remarkable progress that is now accelerating in all domains, in spite of inherent limitations to predictive capacity. Climate change science is now contributing to the foundation of a new interdisciplinary approach to understanding our environment. Consequently, much published research and many notable scientific advances have occurred since the TAR, including advances in the understanding and treatment of uncertainty. Key aspects of recent climate change research are assessed in Chapters 2 through 11 of this report.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Chapter I

[EPA–HQ–OAR–2009–0171; FRL–9091–8]

RIN 2060–ZA14

Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Administrator finds that six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations. The Administrator also finds that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare under CAA section 202(a). These Findings are based on careful consideration of the full weight of scientific evidence and a thorough review of numerous public comments received on the Proposed Findings published April 24, 2009.

DATES: These Findings are effective on January 14, 2010.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2009–0171. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Jeremy Martinich, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (202) 343–9927; fax number: (202) 343–2202; e-mail address: *ghgendangerment@epa.gov*. For additional information regarding these Findings, please go to the Web site *http://www.epa.gov/climatechange/endangerment.html*.

SUPPLEMENTARY INFORMATION:

Judicial Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by February 16, 2010. Under CAA section 307(d)(7)(B), only an objection to this final action that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, "'[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.'" Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ACUS	Administrative Conference of the United States
ANPR	Advance Notice of Proposed Rulemaking
APA	Administrative Procedure Act
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIT	Climate Analysis Indicators Tool
CASAC	Clean Air Scientific Advisory Committee
CBI	Confidential Business Information
CCSP	Climate Change Science Program
CFCs	chlorofluorocarbons
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2e	CO_2-equivalent
CRU	Climate Research Unit
DOT	U.S. Department of Transportation
EO	Executive Order
EPA	U.S. Environmental Protection Agency
FR	**Federal Register**
GHG	greenhouse gas
GWP	global warming potential
HadCRUT	Hadley Centre/Climate Research Unit (CRU) temperature record
HCFCs	hydrochlorofluorocarbons
HFCs	hydrofluorocarbons
IA	Interim Assessment report
IPCC	Intergovernmental Panel on Climate Change
MPG	miles per gallon
MWP	Medieval Warm Period
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NASA	National Aeronautics and Space Administration
NF_3	nitrogen trifluoride
NHTSA	National Highway Traffic Safety Administration
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
NO_X	nitrogen oxides
NRC	National Research Council
NSPS	new source performance standards
NTTAA	National Technology Transfer and Advancement Act of 1995
OMB	Office of Management and Budget
PFCs	perfluorocarbons
PM	particulate matter
PSD	Prevention of Significant Deterioration
RFA	Regulatory Flexibility Act
SF_6	sulfur hexafluoride
SIP	State Implementation Plan
TSD	technical support document
U.S.	United States
UMRA	Unfunded Mandates Reform Act of 1995
UNFCCC	United Nations Framework Convention on Climate Change
USGCRP	U.S. Global Climate Research Program
VOC	volatile organic compound(s)
WCI	Western Climate Initiative
WRI	World Resources Institute

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I. Introduction

A. Overview

Pursuant to CAA section 202(a), the Administrator finds that greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare. Specifically, the Administrator is defining the ''air pollution'' referred to in CAA section 202(a) to be the mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). In this document, these six greenhouse gases are referred to as ''well-mixed greenhouse gases'' in this document (with more precise meanings of ''long lived'' and ''well mixed'' provided in Section IV.A).

The Administrator has determined that the body of scientific evidence compellingly supports this finding. The major assessments by the U.S. Global Climate Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) serve as the primary scientific basis supporting the Administrator's endangerment finding.[1] The Administrator reached her determination by considering both observed and projected effects of greenhouse gases in the atmosphere, their effect on climate, and the public health and welfare risks and impacts associated with such climate change. The Administrator's assessment focused on public health and public welfare impacts within the United States. She also examined the evidence with respect to impacts in other world regions, and she concluded that these impacts strengthen the case for endangerment to public health and welfare because impacts in other world regions can in turn adversely affect the United States.

The Administrator recognizes that human-induced climate change has the potential to be far-reaching and multi-dimensional, and in light of existing knowledge, that not all risks and potential impacts can be quantified or characterized with uniform metrics. There is variety not only in the nature and potential magnitude of risks and impacts, but also in our ability to characterize, quantify and project such impacts into the future. The Administrator is using her judgment, based on existing science, to weigh the threat for each of the identifiable risks, to weigh the potential benefits where relevant, and ultimately to assess whether these risks and effects, when viewed in total, endanger public health or welfare.

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public health by evaluating the risks associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food- and water-borne pathogens, and changes in aeroallergens. The evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding. Increases in ambient ozone are expected to occur over broad areas of the country, and they are expected to increase serious adverse health effects in large population areas that are and may continue to be in nonattainment. The evaluation of the potential risks associated with increases in ozone in attainment areas also supports such a finding.

The impact on mortality and morbidity associated with increases in average temperatures, which increase the likelihood of heat waves, also provides support for a public health endangerment finding. There are uncertainties over the net health impacts of a temperature increase due to decreases in cold-related mortality, but some recent evidence suggests that the net impact on mortality is more likely to be adverse, in a context where heat is already the leading cause of weather-related deaths in the United States.

The evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be

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[1] Section III of these Findings discusses the science on which these Findings are based. In addition, the Technical Support Document (TSD) accompanying these Findings summarizes the major assessments from the USGCRP, IPCC, and NRC.

adversely affected by an increase in the severity of coastal storm events due to rising sea levels.

There is some evidence that elevated carbon dioxide concentrations and climate changes can lead to changes in aeroallergens that could increase the potential for allergenic illnesses. The evidence on pathogen borne disease vectors provides directional support for an endangerment finding. The Administrator acknowledges the many uncertainties in these areas. Although these adverse effects provide some support for an endangerment finding, the Administrator is not placing primary weight on these factors.

Finally, the Administrator places weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to these climate-related health effects.

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public welfare by evaluating numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. For each of these sectors, the evidence provides support for a finding of endangerment to public welfare. The evidence concerning adverse impacts in the areas of water resources and sea level rise and coastal areas provides the clearest and strongest support for an endangerment finding, both for current and future generations. Strong support is also found in the evidence concerning infrastructure and settlements, as well ecosystems and wildlife. Across the sectors, the potential serious adverse impacts of extreme events, such as wildfires, flooding, drought, and extreme weather conditions, provide strong support for such a finding.

Water resources across large areas of the country are at serious risk from climate change, with effects on water supplies, water quality, and adverse effects from extreme events such as floods and droughts. Even areas of the country where an increase in water flow is projected could face water resource problems from the supply and water quality problems associated with temperature increases and precipitation variability, as well as the increased risk of serious adverse effects from extreme events, such as floods and drought. The severity of risks and impacts is likely to increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

Overall, the evidence on risk of adverse impacts for coastal areas provides clear support for a finding that greenhouse gas air pollution endangers the welfare of current and future generations. The most serious potential adverse effects are the increased risk of storm surge and flooding in coastal areas from sea level rise and more intense storms. Observed sea level rise is already increasing the risk of storm surge and flooding in some coastal areas. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. Even if there is a low probability of raising the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution. In addition, coastal areas face other adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss. The increased risk associated with these adverse impacts also endangers public welfare, with an increasing risk of greater adverse impacts in the future.

Strong support for an endangerment finding is also found in the evidence concerning energy, infrastructure, and settlements, as well ecosystems and wildlife. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to result in an increase in electricity production, especially supply for peak demand. This may be exacerbated by the potential for adverse impacts from climate change on hydropower resources as well as the potential risk of serious adverse effects on energy infrastructure from extreme events. Changes in extreme weather events threaten energy, transportation, and water resource infrastructure. Vulnerabilities of industry, infrastructure, and settlements to climate change are generally greater in high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Climate change will likely interact with and possibly exacerbate ongoing environmental change and environmental pressures in settlements, particularly in Alaska where indigenous communities are facing major environmental and cultural impacts on their historic lifestyles. Over the 21st century, changes in climate will cause some species to shift north and to higher elevations and fundamentally rearrange U.S. ecosystems. Differential capacities for range shifts and constraints from development, habitat fragmentation, invasive species, and broken ecological connections will likely alter ecosystem structure, function, and services, leading to predominantly negative consequences for biodiversity and the provision of ecosystem goods and services.

There is a potential for a net benefit in the near term[2] for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector may be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops. However, The body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture over time, with the potential for significant disruptions and crop failure in the future.

For the near term, the Administrator finds the beneficial impact on forest growth and productivity in certain parts of the country from elevated carbon dioxide concentrations and temperature increases to date is offset by the clear risk from the observed increases in wildfires, combined with risks from the spread of destructive pests and disease. For the longer term, the risk from adverse effects increases over time, such that overall climate change presents serious adverse risks for forest productivity. There is compelling reason to find that the support for a positive endangerment finding increases as one considers expected future conditions where temperatures continue to rise.

Looking across all of the sectors discussed above, the evidence provides compelling support for finding that greenhouse gas air pollution endangers the public welfare of both current and

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[2] The temporal scope of impacts is discussed in more detail in Section III.C. The phrase ''near term'' as used in this document generally refers to the current time period from and the next few decades. The phrase ''long term'' generally refers to a time frame extending beyond that to approximately the middle to the end of this century.

future generations. The risk and the severity of adverse impacts on public welfare are expected to increase over time.

The Administrator also finds that emissions of well-mixed greenhouse gases from the transportation sources covered under CAA section 202(a)[3] contribute to the total greenhouse gas air pollution, and thus to the climate change problem, which is reasonably anticipated to endanger public health and welfare. The Administrator is defining the air pollutant that contributes to climate change as the aggregate group of the well-mixed greenhouse gases. The definition of air pollutant used by the Administrator is based on the similar attributes of these substances. These attributes include the fact that they are sufficiently long-lived to be well mixed globally in the atmosphere, that they are directly emitted, and that they exert a climate warming effect by trapping outgoing, infrared heat that would otherwise escape to space, and that they are the focus of climate change science and policy.

In order to determine if emissions of the well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution that endangers public health and welfare, the Administrator compared the emissions from these CAA section 202(a) source categories to total global and total U.S. greenhouse gas emissions, finding that these source categories are responsible for about 4 percent of total global well-mixed greenhouse gas emissions and just over 23 percent of total U.S. well-mixed greenhouse gas emissions. The Administrator found that these comparisons, independently and together, clearly establish that these emissions contribute to greenhouse gas concentrations. For example, the emissions of well-mixed greenhouse gases from CAA section 202(a) sources are larger in magnitude than the total well-mixed greenhouse gas emissions from every other individual nation with the exception of China, Russia, and India, and are the second largest emitter within the United States behind the electricity generating sector. As the Supreme Court noted, ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts* v. *EPA,* 549 U.S. 497, 525 (2007).

The Administrator's findings are in response to the Supreme Court's decision in *Massachusetts* v. *EPA.* That case involved a 1999 petition submitted by the International Center for Technology Assessment and 18 other environmental and renewable energy industry organizations requesting that EPA issue standards under CAA section 202(a) for the emissions of carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons from new motor vehicles and engines. The Administrator's findings are in response to this petition and are for purposes of CAA section 202(a).

B. Background Information Helpful To Understand These Findings

This section provides some basic information regarding greenhouse gases and the CAA section 202(a) source categories, as well as the ongoing joint-rulemaking on greenhouse gases by EPA and the Department of Transportation. Additional technical and legal background, including a summary of the Supreme Court's *Massachusetts* v. *EPA* decision, can be found in the Proposed Endangerment and Contribution Findings (74 FR 18886, April 24, 2009).

1. Greenhouse Gases and Transportation Sources Under CAA Section 202(a)

Greenhouse gases are naturally present in the atmosphere and are also emitted by human activities. Greenhouse gases trap the Earth's heat that would otherwise escape from the atmosphere, and thus form the greenhouse effect that helps keep the Earth warm enough for life. Human activities are intensifying the naturally-occurring greenhouse effect by adding greenhouse gases to the atmosphere. The primary greenhouse gases of concern that are directly emitted by human activities include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Other pollutants (such as aerosols) and other human activities, such as land use changes that alter the reflectivity of the Earth's surface, also cause climatic warming and cooling effects. In these Findings, the term ''climate change'' generally refers to the global warming effect plus other associated changes (*e.g.,* precipitation effects, sea level rise, changes in the frequency and severity of extreme weather events) being induced by human activities, including activities that emit greenhouse gases. Natural causes also, contribute to climate change and climatic changes have occurred throughout the Earth's history. The concern now, however, is that the changes taking place in our atmosphere as a result of the well-documented buildup of greenhouse gases due to human activities are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Further detail on the state of climate change science can be found in Section III of these Findings as well as the technical support document (TSD) that accompanies this action (*www.epa.gov/climatechange/endangerment.html*).

The transportation sector is a major source of greenhouse gas emissions both in the United States and in the rest of the world. The transportation sources covered under CAA section 202(a)—the section of the CAA under which these Findings occur—include passenger cars, light- and heavy-duty trucks, buses, and motorcycles. These transportation sources emit four key greenhouse gases: carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. Together, these transportation sources are responsible for 23 percent of total annual U.S. greenhouse gas emissions, making this source the second largest in the United States behind electricity generation.[4]

Further discussion of the emissions data supporting the Administrator's cause or contribute finding can be found in Section V of these Findings, and the detailed greenhouse gas emissions data for section 202(a) source categories can be found in Appendix B of EPA's TSD.

2. Joint EPA and Department of Transportation Proposed Greenhouse Gas Rule

On September 15, 2009, EPA and the Department of Transportation's National Highway Safety Administration (NHTSA) proposed a National Program that would dramatically reduce greenhouse gas emissions and improve fuel economy for new cars and trucks sold in the United States. The combined EPA and NHTSA standards that make up this proposed National Program would apply to passenger cars, light-duty trucks, and medium-duty passenger vehicles, covering model years 2012 through 2016. They proposed to require these vehicles to meet an estimated combined average

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[3] Section 202(a) source categories include passenger cars, heavy-, medium and light-duty trucks, motorcycles, and buses.

[4] The units for greenhouse gas emissions in these findings are provided in carbon dioxide equivalent units, where carbon dioxide is the reference gas and every other greenhouse gas is converted to its carbon dioxide equivalent by using the 100-year global warming potential (as estimated by the Intergovernmental Panel on Climate Change (IPCC). assigned to each gas. The reference gas used is CO_2, and therefore Global Warming Potential (GWP)-weighted emissions are measured in teragrams of CO_2 equivalent (Tg CO_2 eq.). In accordance with UNFCCC reporting procedures, the United States quantifies greenhouse gas emissions using the 100-year time frame values for GWPs established in the IPCC Second Assessment Report.

emissions level of 250 grams of carbon dioxide per mile, equivalent to 35.5 miles per gallon (MPG) if the automobile industry were to meet this carbon dioxide level solely through fuel economy improvements. Together, these proposed standards would cut carbon dioxide emissions by an estimated 950 million metric tons and 1.8 billion barrels of oil over the lifetime of the vehicles sold under the program (model years 2012–2016). The proposed rulemaking can be viewed at (74 FR 49454, September 28, 2009).

C. Public Involvement

In response to the Supreme Court's decision, EPA has been examining the scientific and technical basis for the endangerment and cause or contribute decisions under CAA section 202(a) since 2007. The science informing the decision-making process has grown stronger since our work began. EPA's approach to evaluating the science, including comments submitted during the public comment period, is further discussed in Section III.A of these Findings. Public review and comment has always been a major component of EPA's process.

1. EPA's Initial Work on Endangerment

As part of the *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act* (73 FR 44353) published in July 2008, EPA provided a thorough discussion of the issues and options pertaining to endangerment and cause or contribute findings under the CAA. The Agency also issued a TSD providing an overview of all the major scientific assessments available at the time and emission inventory data relevant to the contribution finding (Docket ID No. EPA–HQ–OAR–2008–0318). The comment period for that *Advance Notice* was 120 days, and it provided an opportunity for EPA to hear from the public with regard to the issues involved in endangerment and cause or contribute findings as well as the supporting science. EPA received, reviewed and considered numerous comments at that time and this public input was reflected in the Findings that the Administrator proposed in April 2009. In addition, many comments were received on the TSD released with the *Advance Notice* and reflected in revisions to the TSD released in April 2009 to accompany the Administrator's proposal. All public comments on the *Advance Notice* are contained in the public docket for this action (Docket ID No. EPA–HQ–OAR–2008–0318) accessible through *www.regulations.gov.*

2. Public Involvement Since the April 2009 Proposed Endangerment Finding

The Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases (Proposed Findings) was published on April 24, 2009 (74 FR 18886). The Administrator's proposal was subject to a 60-day public comment period, which ended June 23, 2009, and also included two public hearings. Over 380,000 public comments were received on the Administrator's proposed endangerment and cause or contribute findings, including comments on the elements of the Administrator's April 2009 proposal, the legal issues pertaining to the Administrator's decisions, and the underlying TSD containing the scientific and technical information.

A majority of the comments (approximately 370,000) were the result of mass mail campaigns, which are defined as groups of comments that are identical or very similar in form and content. Overall, about two-thirds of the mass-mail comments received are supportive of the Findings and generally encouraged the Administrator both to make a positive endangerment determination and implement greenhouse gas emission regulations. Of the mass mail campaigns in disagreement with the Proposed Findings most either oppose the proposal on economic grounds (*e.g.,* due to concern for regulatory measures following an endangerment finding) or take issue with the proposed finding that atmospheric greenhouse gas concentrations endanger public health and welfare. Please note that for mass mailer campaigns, a representative copy of the comment is posted in the public docket for this Action (Docket ID No. EPA–HQ–OAR–2009–0171) at *www.regulations.gov.*

Approximately 11,000 other public comments were received. These comments raised a variety of issues related to the scientific and technical information EPA relied upon in making the Proposed Findings, legal and procedural issues, the content of the Proposed Findings, and the implications of the Proposed Findings.

In light of the very large number of comments received and the significant overlap between many comments, EPA has not responded to each comment individually. Rather, EPA has summarized and provided responses to each significant argument, assertion and question contained within the totality of the comments. EPA's responses to some of the most significant comments are provided in these Findings. Responses to all significant issues raised by the comments are contained in the 11 volumes of the Response to Comments document, organized by subject area (found in docket EPA–HQ–OAR–2009–0171).

3. Issues Raised Regarding the Rulemaking Process

EPA received numerous comments on process-related issues, including comments urging the Administrator to delay issuing the final findings, arguing that it was improper for the Administrator to sever the endangerment and cause or contribute findings from the attendant section 202(a) standards, arguing the final decision was preordained by the President's May vehicle announcement, and questioning the adequacy of the comment period. Summaries of key comments and EPA's responses are discussed in this section. Additional and more detailed responses can be found in the Response to Comments document, Volume 11. As noted in the Response to Comments document, EPA also received comments supporting the overall process.

a. It Is Reasonable for the Administrator To Issue the Endangerment and Cause or Contribute Findings Now

Though the Supreme Court did not establish a specific deadline for EPA to act, more than two and a half years have passed since the remand from the Supreme Court, and it has been 10 years since EPA received the original petition requesting that EPA regulate greenhouse gas emissions from new motor vehicles. EPA has a responsibility to respond to the Supreme Court's decision and to fulfill its obligations under current law, and there is good reason to act now given the urgency of the threat of climate change and the compelling scientific evidence.

Many commenters urge EPA to delay making final findings for a variety of reasons. They note that the Supreme Court did not establish a deadline for EPA to act on remand. Commenters also argue that the Supreme Court's decision does not require that EPA make a final endangerment finding, and thus that EPA has discretionary power and may decline to issue an endangerment finding, not only if the science is too uncertain, but also if EPA can provide ''some reasonable explanation'' for exercising its discretion. These commenters interpret the Supreme Court decision not as rejecting all policy reasons for declining to undertake an endangerment finding, but rather as dismissing solely the policy reasons EPA set forth in 2003. Some commenters cite language in the

Supreme Court decision regarding EPA's discretion regarding ''the manner, timing, content, and coordination of its regulations,'' and the Court's declining to rule on ''whether policy concerns can inform EPA's actions in the event that it makes'' a CAA section 202(a) finding to support their position.

Commenters then suggest a variety of policy reasons that EPA can and should make to support a decision not to undertake a finding of endangerment under CAA section 202(a)(1). For example, they argue that a finding of endangerment would trigger several other regulatory programs—such as the Prevention of Significant Deterioration (PSD) provisions—that would impose an unreasonable burden on the economy and government, without providing a benefit to the environment. Some commenters contend that EPA should defer issuing a final endangerment finding while Congress considers legislation. Many commenters note the ongoing international discussions regarding climate change and state their belief that unilateral EPA action would interfere with those negotiations. Others suggest deferring the EPA portion of the joint U.S. Department of Transportation (DOT)/EPA rulemaking because they argue that the new Corporate Average Fuel Economy (CAFE) standards will effectively result in lower greenhouse gas emissions from new motor vehicles, while avoiding the inevitable problems and concerns of regulating greenhouse gases under the CAA.

Other commenters argue that the endangerment determination has to be made on the basis of scientific considerations only. These commenters state that the Court was clear that ''[t]he statutory question is whether sufficient information exists to make an endangerment finding,'' and thus, only if ''the scientific uncertainty is so profound that it precludes EPA from making a reasoned judgment as to whether greenhouse gases contribute to global warming,'' may EPA avoid making a positive or negative endangerment finding. Many commenters urge EPA to take action quickly. They note that it has been 10 years since the original petition requesting that EPA regulate greenhouse gas emissions from motor vehicles was submitted to EPA. They argue that climate change is a serious problem that requires immediate action.

EPA agrees with the commenters who argue that the Supreme Court decision held that EPA is limited to consideration of science when undertaking an endangerment finding, and that we cannot delay issuing a finding due to policy concerns if the science is sufficiently certain (as it is here). The Supreme Court stated that ''EPA can avoid taking further action only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do'' 549 U.S. at 533. Some commenters point to this last provision, arguing that the policy reasons they provide are a ''reasonable explanation'' for not moving forward at this time. However, this ignores other language in the decision that clearly indicates that the Court interprets the statute to allow for the consideration only of science. For example, in rejecting the policy concerns expressed by EPA in its 2003 denial of the rulemaking petition, the Court noted that ''it is evident [the policy considerations] have nothing to do with whether greenhouse gas emissions contribute to climate change. Still less do they amount to a reasoned justification for declining to form *a scientific judgment'' Id.* at 533–34 (emphasis added).

Moreover, the Court also held that ''[t]he statutory question is whether sufficient information exists to make an endangerment finding'' *Id.* at 534. Taken as a whole, the Supreme Court's decision clearly indicates that policy reasons do not justify the Administrator avoiding taking further action on the question here.

We also note that the language many commenters quoted from the Supreme Court decision about EPA's discretion regarding the manner, timing and content of Agency actions, and the ability to consider policy concerns, relate to the motor vehicle standards required in the event that EPA makes a positive endangerment finding, and not the finding itself. EPA has long taken the position that it does have such discretion in the standard-setting step under CAA section 202(a).

b. The Administrator Reasonably Proceeded With the Endangerment and Cause or Contribute Findings Separate From the CAA Section 202(a) Standard Rulemaking

As discussed in the Proposed Findings, typically endangerment and cause or contribute findings have been proposed concurrently with proposed standards under various sections of the CAA, including CAA section 202(a). EPA received numerous comments on its decision to propose the endangerment and cause or contribute findings separate from any standards under CAA section 202(a).

Commenters argue that EPA has no authority to issue an endangerment determination under CAA section 202(a) separate and apart from the rulemaking to establish emissions standards under CAA section 202(a). According to these commenters, CAA section 202(a) provides only one reason to issue an endangerment determination, and that is as the basis for promulgating emissions standards for new motor vehicles; thus, it does not authorize such a stand-alone endangerment finding, and EPA may not create its own procedural rules completely divorced from the statutory text. They continue by stating that while CAA section 202(a) says EPA may issue emissions standards conditioned on such a finding, it does not say EPA may first issue an endangerment determination and then issue emissions standards. In addition, they contend, the endangerment proposal and the emissions standards proposal need to be issued together so commenters can fully understand the implications of the endangerment determination. Failure to do so, they argue, deprives the commenters of the opportunity to assess the regulations that will presumably follow from an endangerment finding. They also argue that the expected overlap between reductions in emissions of greenhouse gases from CAA section 202(a) standards issued by EPA and CAFE standards issued by DOT calls into question the basis for the CAA section 202(a) standards and the related endangerment finding, and that EPA is improperly motivated by an attempt to trigger a cascade of regulations under the CAA and/or to promote legislation by Congress.

EPA disagrees with the commenters' claims and arguments. The text of CAA section 202(a) is silent on this issue. It does not specify the timing of an endangerment finding, other than to be clear that emissions standards may not be issued unless such a determination has been made. EPA is exercising the procedural discretion that is provided by CAA section 202(a)'s lack of specific direction. The text of CAA section 202(a) envisions two separate actions by the Administrator: (1) A determination on whether emissions from classes or categories of new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger, and (2) a separate decision on issuance of appropriate emissions standards for such classes or categories. The procedure followed in this rulemaking, and the companion rulemaking involving emissions standards for light duty motor vehicles, is consistent with CAA section 202(a). EPA will issue final emissions standards for new motor vehicles only if affirmative findings are made concerning contribution and endangerment, and such emissions standards will not be finalized prior to making any such determinations. While it would also be consistent with CAA section 202(a) to issue the greenhouse gas endangerment and contribution findings and emissions standards for new light-duty vehicles in the same rulemaking, *e.g.,* a single proposal covering them and a single final rule covering them, nothing in CAA section 202(a) requires such a procedural approach, and nothing in the approach taken in this case violates the text of CAA section 202(a). Since Congress was silent on this issue, and more than one procedural approach may accomplish the requirements of CAA section 202(a), EPA has the discretion to use the approach considered appropriate in this case. Once the final affirmative contribution and endangerment findings are made, EPA has the authority to issue the final emissions standards for new light-duty motor vehicles; however, as the Supreme Court has noted, the agency has 'significant latitude as to the manner, timing, [and] content * * * of its regulations . * * *' *Massachusetts v. EPA,* 549 U.S. at 533. That includes the discretion to issue them in a separate rulemaking.

Commenters' argument would also lead to the conclusion that EPA could not make an endangerment finding for the entire category of new motor vehicles, as it is doing here, unless EPA also conducted a rulemaking that set emissions standards for all the classes and categories of new motor vehicles at the same time. This narrow procedural limitation would improperly remove discretion that CAA section 202(a) provides to EPA.

EPA has the discretion under CAA section 202(a) to consider classes or categories of new motor vehicles separately or together in making a contribution and endangerment determination. This discretion would be removed under commenters' interpretation, by limiting this to only those cases in which EPA was also ready to issue emissions standards for all of the classes or categories covered by the endangerment finding. However, nothing in the text of CAA section 202(a) places such a limit on EPA's discretion in determining how to group classes or categories of new motor vehicles for purposes of the contribution and endangerment findings. This limitation would not be appropriate, because the issues of contribution and endangerment are separate and distinct from the issues of setting emissions standards. EPA, in this case, is fully prepared to go forward with the contribution and endangerment determination, while it is not ready to proceed with rulemaking for each and every category of new motor vehicles in the first rulemaking to set emissions standards. Section 202(a) of the CAA provides EPA discretion with regard to when and how it conducts its rulemakings to make contribution and endangerment findings, and to set emissions standards, and the text of CAA section 202(a) does not support commenters attempt to limit such discretion.

Concerns have been raised that the failure to issue the proposed endangerment finding and the proposed emissions standard together preclude commenters from assessing and considering the implications of the endangerment finding and the regulations that would likely flow from such a finding. However, commenters have failed to explain how this interferes in any way with their ability to comment on the endangerment finding. In fact it does not interfere, because the two proposals address separate and distinct issues. The endangerment finding concerns the contribution of new motor vehicles to air pollution and the effect of that air pollution on public health or welfare. The emissions standards, which have been proposed (74 FR 49454, September 28, 2009), concern the appropriate regulatory emissions standards if affirmative findings are made on contribution and endangerment. These two proposals address different issues. While commenters have the opportunity to comment on the proposed emissions standards in that rulemaking, they have not shown, and cannot show, that they need to have the emissions standards proposal before them in order to provide relevant comments on the proposed contribution or endangerment findings. Further discussion of this issue can be found in Section II of these Findings, and discussion of the timing of this action and its relationship to other CAA provisions and Congressional action can be found in Section III of these Findings and Volume 11 of the Response to Comments document.

c. The Administrator's Final Decision Was Not Preordained by the President's May Vehicle Announcement

EPA received numerous comments arguing that the President's announcement of a new ''National Fuel Efficiency Policy'' on May 19, 2009 seriously undermines EPA's ability to provide objective consideration of and a legally adequate response to comments objecting to the previously proposed endangerment findings.

Commenters' conclusion is based on the view that the President's announced policy requires EPA to promulgate greenhouse gas emissions standards under CAA section 202(a), that the President's and Administrator Jackson's announcement indicated that the endangerment rulemaking was but a formality and that a final endangerment finding was a fait accompli. Commenters argue that this means the result of this rulemaking has been preordained and the merits of the issues have been prejudged.

EPA disagrees. Commenters' arguments wholly exaggerate and mischaracterize the circumstances. In the April 24, 2009 endangerment proposal EPA was clear that the two steps in the endangerment provision have to be satisfied in order for EPA to issue emissions standards for new motor vehicles under CAA section 202(a) (74 FR at 18888, April 24, 2009). This was repeated when EPA issued the Notice of Upcoming Joint Rulemaking to Establish Vehicle GHG Emissions and CAFE Standards (74 FR 24007 May 22, 2009) (Notice of Intent or NOI). This was repeated again when EPA issued proposed greenhouse gas emissions standards for certain new motor vehicles (74 FR 49454, September 28, 2009). EPA has consistently made it clear that issuance of new motor vehicle standards requires and is contingent upon satisfaction of the two-part endangerment test.

On May 19, 2009 EPA issued the joint Notice of Intent, which indicated EPA's intention to propose new motor vehicle standards. All of the major motor vehicle manufacturers, their trade associations, the State of California, and several environmental organizations announced their full support for the upcoming rulemaking. Not surprisingly, on the same day the President also announced his full support for this action. Commenters, however, erroneously equate this Presidential support with a Presidential directive that requires EPA to prejudge and preordain the result of this rulemaking.

The only evidence they point to are simply indications of Presidential support. Commenters point to a press release, which unsurprisingly refers to the Agency's announcement as delivering on the President's commitment to enact more stringent fuel economy standards, by bringing ''all stakeholders to the table and [coming] up with a plan'' for solving a serious problem. The plan that was announced, of course, was a plan to conduct notice and comment rulemaking. The press release itself states that President Obama ''set in motion a new national policy,'' with the policy ''aimed'' at reducing greenhouse gas emissions for new cars and trucks. What was ''set in motion'' was a notice and comment rulemaking described in the NOI issued by EPA on the same day. Neither the President nor EPA announced a final rule or a final direction that day, but instead did no more than announce a plan to go forward with a notice and comment rulemaking. That is how the plan ''delivers on the President's commitment'' to enact more stringent standards. The announcement was that a notice and comment rulemaking would be initiated with the aim of adopting certain emissions standards.

That is no different from what EPA or any other agency states when it issues a notice of proposed rulemaking. It starts a process that has the aim of issuing final regulations if they are deemed appropriate at the end of the public process. The fact that an Agency proposes a certain result, and expects that a final rule will be the result of setting such a process in motion, is the ordinary course of affairs in notice and comment rulemakings. This does not translate into prejudging the final result or having a preordained result that de facto negates the public comment process. The President's press release of May 19, 2009 was a recognition that this notice and comment rulemaking process would be set in motion, as well as providing his full support for the Agency to go forward in this direction; it was no more than that.

The various stakeholders who announced their support for the plan that had been set in motion all recognized that full notice and comment rulemaking was part of the plan, and they all reserved their rights to participate in such notice and comment rulemaking. For example, see the letter of support from Ford Motor Company, which states that ''Ford fully supports proposal and adoption of such a National Program, which we understand will be subject to full notice-and-comment rulemaking, affording all interested parties including Ford the right to participate fully, comment, and submit information, the results of which are not pre-determined but depend upon processes set by law.''

d. The Notice and Comment Period Was Adequate

Many commenters argue that the 60-day comment period was inadequate. Commenters claim that a 60-day period was insufficient time to fully evaluate the science and other information that informed the Administrator's proposal. Some commenters assert that because the comment period for the Proposed Finding substantially overlapped with the comment period for the Mandatory Greenhouse Gas Reporting Rule, as well as Congress' consideration of climate legislation, their ability to fully participate in the notice and comment period was ''seriously compromised.'' Moreover, they continue, because EPA had not yet proposed CAA section 202(a) standards, there was no valid reason to fail to extend the comment period. Several commenters and other entities had also requested that EPA extend the comment period.

Some commenters assert that the notice provided by this rulemaking was ''defective'' because the **Federal Register** notice announcing the proposal had an error in the e-mail address for the docket. At least one commenter suggests that this error deprives potential commenters of their Due Process under the Fifth Amendment of the Constitution, citing *Armstrong* v. *Manzo,* 380 U.S. 545, 552 (1965), and that failure to ''correct'' the minor typographical error in the e-mail address and extend the comment period would make the rule ''subject to reversal'' in violation of the CAA, Administrative Procedure Act (APA), the Due Process clause of the Constitution, and EO 12866.

Finally, for many of the same reasons that commenters argue a 60-day comment period was inadequate, several commenters request that EPA reopen and/or extend the comment period. One commenter requests that the comment period be reopened because there was new information regarding data used by EPA in the Proposed Findings. In particular, the commenter alleges that it recently became aware that one of the sources of global climate data had destroyed the raw data for its data set of global surface temperatures. The commenter argues that this alleged destruction of raw data violates scientific standards, calls into question EPA's reliance on that data in these Findings, and necessitates a reopening of the proceedings. Other commenters request that the comment period be extended and/or reopened due to the release of a Federal government document on the impact of climate change in the United States near the end of the comment period, as well as the release of an internal EPA staff document discussing the science.

The official public comment period on the proposed rule was adequate. First, a 60-day comment period satisfies the procedural requirements of CAA section 307 of the CAA, which requires a 30-day comment period, and that the docket be kept open to receive rebuttal or supplemental information as follow-up to any hearings for 30 days following the hearings. EPA met those obligations here—the comment period opened on April 24, 2009, the last hearing was on May 21, 2009 and the comment period closed June 23, 2009.

Second, as explained in letters denying requests to extend the comment period, a very large part of the information and analyses for the Proposed Findings had been previously released in July 30, 2008, as part of the *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act (ANPR)* (73 FR 44353). The public comment period for the ANPR is discussed above in Section I.C.1 of these Findings. The Administrator explained that the comment period for that ANPR was 120 days and that the major recent scientific assessments that EPA relied upon in the TSD released with the ANPR had previously each gone through their own public review processes and have been publicly available for some time. In other words, EPA has provided ample time for review, particularly with regard to the technical support for the Findings. See, for example, EPA Letter to Congressman Issa dated June 17, 2009, a copy of which is available at *http://epa.gov/climatechange/endangerment.html.*

Moreover, the comment period was not rendered insufficient merely because other climate-related proceedings were occurring simultaneously.

While one commenter suggests that the convergence of several different climate-related activities has ''seriously compromised'' their ability to participate in the comment process, that commenter was able to submit an 89 page comment on this proposal alone. Moreover, it is hardly rare that more than one rule is out for comment at the same time. As noted above, EPA has received a substantial number of significant comments on the Proposed Findings, and has thoroughly considered and responded to significant comments.

EPA finds no evidence that a typographical error in the docket e-mail address of the **Federal Register** notice announcing the proposal prevented the public from having a meaningful opportunity to comment, and therefore deprived them of due process. Although the minor error—which involved a word processing auto-correction that turned a short dash into a long dash—appeared in the FR version of the Proposed Findings, the e-mail address is correct in the signature version of the Proposed Findings posted on EPA's Web site until publication in the **Federal Register,** and in the ''Instructions for Submitting Written Comments'' document on the Web site for the rulemaking. EPA has received over 190,000 e-mails to the docket e-mail address to date, so the minor typographical error appearing in only one location has not been an impediment to interested parties' e-mailing comments. Moreover, EPA provided many other avenues for interested parties to submit comments in addition to the docket e-mail address, including via *www.regulations.gov,* mail, and fax; each of these options have been utilized by many commenters. EPA is confident that the minor typographical error did not prevent anyone from submitting written comments, by e-mail or otherwise, and that the public was provided ''meaningful participation in the regulatory process'' as mentioned in EO 12866.

Our response regarding the request to reopen the comment period due to concerns about alleged destruction of raw global surface data is discussed more fully in the Response to Comments document, Volume 11. The commenter did not provide any compelling reason to conclude that the absence of these data would materially affect the trends in the temperature records or conclusions drawn about them in the assessment literature and reflected in the TSD. The Hadley Centre/Climate Research Unit (CRU) temperature record (referred to as HadCRUT) is just one of three global surface temperature records that EPA and the assessment literature refer to and cite. National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA) also produce temperature records, and all three temperature records have been extensively peer reviewed. Analyses of the three global temperature records produce essentially the same long-term trends as noted in the Climate Change Science Program (CCSP) (2006) report ''Temperature Trends in the Lower Atmosphere,'' IPCC (2007), and NOAA's study[5] ''State of the Climate in 2008''. Furthermore, the commenter did not demonstrate that the allegedly destroyed data would materially alter the HadCRUT record or meaningfully hinder its replication. The raw data, a small part of which has not been public (for reasons described at: *https://www.uea.ac.uk/mac/comm/media/press/2009/nov/CRUupdate*), are available in a quality-controlled (or homogenized, value-added) format and the methodology for developing the quality-controlled data is described in the peer reviewed literature (as documented at *http://www.cru.uea.ac.uk/cru/data/temperature/*).

The release of the U.S. Global Climate Research Program (USGCRP) report on impacts of climate change in the United States in June 2009 also did not necessitate extending the comment period. This report was issued by the USGCRP, formerly the Climate Change Science Program (CCSP), and synthesized information contained in prior CCSP reports and other synthesis reports, many of which had already been published (and were included in the TSD for the Proposed Findings). Further, the USGCRP report itself underwent notice and comment before it was finalized and released.

Regarding the internal EPA staff paper that came to light during the comment period, several commenters submitted a copy of the EPA staff paper with their comments; EPA's response to the issues raised by the staff paper are discussed in the Response to Comments document, Volume 1. The fact that some internal agency deliberations were made public during the comment period does not in and of itself call into question those deliberations. As our responses to comments explain, EPA considered the concerns noted in the staff paper during the proposal stage, as well as when finalizing the Findings. There was nothing about those internal comments that required an extension or reopening of the comment period.

Thus, the opportunity for comment fully satisfies the CAA and Constitutional requirement of Due Process. Cases cited by commenters do not indicate otherwise. The comment period and thorough response to comment documents in the docket indicate that EPA has given people an opportunity to be heard in a ''meaningful time and a meaningful matter.'' *Armstrong* v. *Manzo,* 380 U.S. 545, 552 (1965). Interested parties had full notice of the rulemaking proceedings and a significant opportunity to participate through the comment process and multiple hearings.

For all the above reasons, EPA's denial of the requests for extension or reopening of the comment period was entirely reasonable in light of the extensive opportunity for public comment and heavy amount of public participation during the comment period. EPA has fully complied with all applicable public participation requirements for this rulemaking.

e. These Findings Did Not Necessitate a Formal Rulemaking Under the Administrative Procedure Act

One commenter, with the support of others, requests that EPA undertake a formal rulemaking process for the Findings, on the record, in accordance with the procedures described in sections 556–557 of the Administrative Procedure Act (APA). The commenter requests a multi-step process, involving additional public notice, an on-the-record proceeding (*e.g.,* formal administrative hearing) with the right of appeal, utilization of the Clean Air Scientific Advisory Committee (CASAC) and its advisory proceedings, and designation of representatives from other executive branch agencies to participate in the formal proceeding and any CASAC advisory proceeding.

The commenter asserts that while EPA is not obligated under the CAA to undertake these additional procedures, the Agency nonetheless has the legal authority to engage in such a proceeding. The commenter believes this proceeding would show that EPA is ''truly committed to scientific integrity and transparency.'' The commenter cites several cases to argue that refusal to proceed on the record would be ''arbitrary and capricious'' or would be an ''abuse of discretion.'' The allegation at the core of the commenter's argument is that profound and wide-ranging scientific uncertainties exist in the Proposed Findings and in the impacts on health and welfare discussed in the TSD. To support this argument, the commenter provides lengthy criticisms of the science. The commenter also argues that the regulatory cascade that would be ''unleashed'' by a positive endangerment finding warrants the more formal proceedings.

Finally, the commenter suggests that EPA engage in ''formal rulemaking'' procedures in part due to the Administrative Conference of the United States' (ACUS) recommended factors for engaging in formal rulemaking. The commenter argues that the current action is ''complex,'' ''open-ended,'' and the costs that errors in the action may pose are ''significant.''

EPA is denying the request to undertake an ''on the record'' formal rulemaking. EPA is under no obligation to follow the extraordinarily rarely used formal rulemaking provisions of the APA. First, CAA section 307(d) of the CAA clearly states that the rulemaking provisions of CAA section 307(d), *not* APA sections 553 through 557, apply to certain specified actions, such as this

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[5] Peterson, T.C., and M.O. Baringer (Eds.) (2009) State of the Climate in 2008. *Bull. Amer. Meteor. Soc.,* 90, S1–S196.

one. EPA has satisfied all the requirements of CAA section 307(d). Indeed, the commenter itself ''is not asserting that the Clean Air Act expressly requires'' the additional procedures it requests. Moreover, the commenter does not discuss how the suggested formal proceeding would fit into the informal rulemaking requirements of CAA section 307(d) that do apply.

Formal rulemaking is very rarely used by Federal agencies. The formal rulemaking provisions of the APA are only triggered when the statute explicitly calls for proceedings ''on the record after opportunity for an agency hearing.'' *United States* v. *Florida East Coast Ry. Co.,* 410 U.S. 224, 241 (1973). The mere mention of the word ''hearing'' does not trigger the formal rulemaking provisions of the APA. *Id.* The CAA does not include the statutory phrase required to trigger the formal rulemaking provisions of the APA (and as noted above the APA does not apply in the first place). Congress specified that certain rulemakings under the CAA follow the rulemaking procedures outlined in CAA section 307(d) rather than the APA ''formal rulemaking'' commenter suggests.

Despite the inapplicability of the formal rulemaking provisions to this action, commenters suggest that to refuse to voluntarily undertake rulemaking provisions not preferred by Congress would make EPA's rulemaking action an ''abuse of discretion.'' EPA disagrees with this claim, and cases cited by the commenter do not indicate otherwise. To support the idea that an agency decision to engage in informal rulemaking could be an abuse of discretion, commenter cites *Ford Motor Co.* v. *FTC,* 673 F.2d 1008 (9th Cir. 1981). In *Ford Motor Co.,* the court ruled that the FTC's decision regarding an automobile dealership should have been resolved through a rulemaking rather than an individualized adjudication. *Id.* at 1010. In that instance, the court favored ''rulemaking'' over adjudication—not ''formal rulemaking'' over the far more common ''informal rulemaking.'' The case stands only for the non-controversial proposition that sometimes agency use of *adjudications* may rise to an abuse of discretion where a *rulemaking* would be more appropriate—whether formal or informal. The Commenter does not cite a single judicial opinion stating that an agency abused its discretion by following the time-tested and Congressionally-favored informal rulemaking provisions of the CAA or the APA instead of the rarely used formal APA rulemaking provisions.

The commenter also alludes to the possibility that the choice of informal rulemaking may be ''arbitrary and capricious. EPA disagrees that the choice to follow the frequently used, and CAA required, informal rulemaking procedures is arbitrary and capricious. The commenter cites *Vermont Yankee Nuclear Power Corp.* v. *NRDC,* 435 U.S. 519 (1978) for the proposition that ''extremely compelling circumstances'' could lead to a court overturning agency action for declining to follow extraneous procedures. As the commenter notes, in *Vermont Yankee* the Supreme Court overturned a lower court decision for imposing additional requirements not required by applicable statutes. Even if the dicta in *Vermont Yankee* could be applied contrary to the holding of the case in the way the commenter suggests, EPA's decision to follow frequently used informal rulemaking procedures for this action is highly reasonable.

As for the ACUS factors the commenter cites in support of its request, as the commenter notes, the ACUS factors are mere recommendations. While EPA certainly respects the views of ACUS, the recommendations are not binding on the Agency. In addition, EPA has engaged in a thorough, traditional rulemaking process that ensures that any concerns expressed by the commenter have been addressed. EPA has fully satisfied all applicable law in their consideration of this rulemaking.

Finally, as explained in Section III of these Findings and the Response to Comments document, EPA's approach to evaluating the evidence before it was entirely reasonable, and did not require a formal hearing. EPA relied primarily on robust synthesis reports that have undergone peer review and comment. The Agency also carefully considered the comments received on the Proposed Findings and TSD, including review of attached studies and documents. The public has had ample opportunity to provide its views on the science, and the record supporting these final findings indicates that EPA carefully considered and responded to significant public comments. To the extent the commenter's concern is that a formal proceeding will help ensure the *right* action in response to climate change is taken, that is not an issue for these Findings. As discussed in Section III of these Findings, this science-based judgment is not the forum for considering the potential mitigation options or their impact.

II. Legal Framework for This Action

As discussed in the Proposed Findings, two statutory provisions of the CAA govern the Administrator's Findings. Section 202(a) of the CAA sets forth a two-part test for regulatory action under that provision: Endangerment and cause or contribute. Section 302 of the CAA contains definitions of the terms ''air pollutant'' and ''effects on welfare''. Below is a brief discussion of these statutory provisions and how they govern the Administrator's decision, as well as a summary of significant legal comments and EPA's responses to them.

A. Section 202(a) of the CAA—Endangerment and Cause or Contribute

1. The Statutory Framework

Section 202(a)(1) of the CAA states that:

> The Administrator shall by regulation prescribe (and from time to time revise) standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles or new motor vehicle engines, which in [her] judgment cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare.

Based on the text of CAA section 202(a) and its legislative history, the Administrator interprets the two-part test as follows. Further discussion of this two-part test can be found in Section II of the preamble for the Proposed Findings. First, the Administrator is required to protect public health and welfare, but she is not asked to wait until harm has occurred. EPA must be ready to take regulatory action to prevent harm before it occurs. Section 202(a)(1) requires the Administrator to ''anticipate'' ''danger'' to public health or welfare. The Administrator is thus to consider both current and future risks. Second, the Administrator is to exercise judgment by weighing risks, assessing potential harms, and making reasonable projections of future trends and possibilities. It follows that when exercising her judgment the Administrator balances the likelihood and severity of effects. This balance involves a sliding scale; on one end the severity of the effects may be of great concern, but the likelihood low, while on the other end the severity may be less, but the likelihood high. Under either scenario, the Administrator is permitted to find endangerment. If the harm would be catastrophic, the Administrator is permitted to find endangerment even if the likelihood is small.

Because scientific knowledge is constantly evolving, the Administrator may be called upon to make decisions while recognizing the uncertainties and limitations of the data or information available, as risks to public health or welfare may involve the frontiers of scientific or medical knowledge. At the same time, the Administrator must exercise reasoned decision making, and avoid speculative inquiries. Third, as discussed further below, the Administrator is to consider the cumulative impact of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources. Fourth, the Administrator is to consider the risks to all parts of our population, including those who are at greater risk for reasons such as increased susceptibility to adverse health effects. If vulnerable subpopulations are especially at risk, the Administrator is entitled to take that point into account in deciding the question of endangerment. Here too, both likelihood and severity of adverse effects are relevant, including catastrophic scenarios and their probabilities as well as the less severe effects. As explained below, vulnerable subpopulations face serious health risks as a result of climate change.

In addition, by instructing the Administrator to consider whether emissions of an air pollutant cause or contribute to air pollution, the statute is clear that she need not find that emissions from any one sector or group of sources are the sole or even the major part of an air pollution problem. The use of the term ''contribute'' clearly indicates a lower threshold than the sole or major cause. Moreover, the statutory language in CAA section 202(a) does not contain a modifier on its use of the term contribute. Unlike other CAA provisions, it does not require ''significant'' contribution. See, *e.g.,* CAA sections 111(b); 213(a)(2), (4). To be sure, any finding of a ''contribution'' requires some threshold to be met; a truly trivial or de minimis ''contribution'' might not count as such. The Administrator therefore has ample discretion in exercising her reasonable judgment in determining whether, under the circumstances presented, the cause or contribute criterion has been met. Congress made it clear that the Administrator is to exercise her judgment in determining contribution, and authorized regulatory controls to address air pollution even if the air pollution problem results from a wide variety of sources. While the endangerment test looks at the entire air pollution problem and the risks it poses, the cause or contribute test is designed to authorize EPA to identify and then address what may well be many different sectors or groups of sources that are each part of—and thus contributing to—the problem.

This framework recognizes that regulatory agencies such as EPA must be able to deal with the reality that ''[m]an's ability to alter his environment has developed far more rapidly than his ability to foresee with certainty the effects of his alterations.'' See *Ethyl Corp* v. *EPA,* 541 F.2d 1, 6 (DC Cir.), *cert. denied* 426 U.S. 941 (1976). Both ''the Clean Air Act 'and common sense * * * demand regulatory action to prevent harm, even if the regulator is less than certain that harm is otherwise inevitable.' '' See *Massachusetts* v. *EPA,* 549 U.S. at 506, n.7 (citing *Ethyl Corp.*).

The Administrator recognizes that the context for this action is unique. There is a very large and comprehensive base of scientific information that has been developed over many years through a global consensus process involving numerous scientists from many countries and representing many disciplines. She also recognizes that there are varying degrees of uncertainty across many of these scientific issues. It is in this context that she is exercising her judgment and applying the statutory framework. As discussed in the Proposed Findings, this interpretation is based on and supported by the language in CAA section 202(a), its legislative history and case law.

2. Summary of Response to Key Legal Comments on the Interpretation of the CAA Section 202(a) Endangerment and Cause or Contribute Test

EPA received numerous comments regarding the interpretation of CAA section 202(a) set forth in the Proposed Findings. Below is a brief discussion of some of the key adverse legal comments and EPA's responses. Other key legal comments and EPA's responses are provided in later sections discussing the Administrator's findings.

Additional and more detailed summaries and responses can be found in the Response to Comments document. As noted in the Response to Comments document, EPA also received comments supporting its legal interpretations.

a. The Administrator Properly Interpreted the Precautionary and Preventive Nature of the Statutory Language

Various commenters argue either that the endangerment test under CAA section 202(a) is not precautionary and preventive in nature, or that EPA's interpretation and application is so extreme that it is contrary to what Congress intended in 1977, and effectively guarantees an affirmative endangerment finding. Commenters also argue that the endangerment test improperly shifts the burdens to the opponents of an endangerment finding and is tantamount to assuming the air pollution is harmful unless it is shown to be safe.

EPA rejects the argument that the endangerment test in CAA section 202(a) is not precautionary or preventive in nature. As discussed in more detail in the proposal, Congress relied heavily on the en banc decision in Ethyl when it revised section 202(a) and other CAA provisions to adopt the current language on endangerment and contribution. 74 FR 18886, 18891–2. The Ethyl court could not have been clearer on the precautionary nature of a criteria based on endangerment. The court rejected the argument that EPA had to find actual harm was occurring before it could make the required endangerment finding. The court stated that:

> *The Precautionary Nature of ''Will Endanger.''* Simply as a matter of plain meaning, we have difficulty crediting petitioners' reading of the ''will endanger'' standard. The meaning of ''endanger'' is not disputed. Case law and dictionary definition agree that endanger means something less than actual harm. When one is endangered, harm is *threatened;* no actual injury need ever occur. Thus, for example, a town may be ''endangered'' by a threatening plague or hurricane and yet emerge from the danger completely unscathed. A statute allowing for regulation in the face of danger is, necessarily, a precautionary statute. Regulatory action may be taken before the threatened harm occurs; indeed, the very existence of such precautionary legislation would seem to *demand* that regulatory action precede, and, optimally, prevent, the perceived threat. As should be apparent, the ''will endanger'' language of Section 211(c)(1)(A) makes it such a precautionary statute. *Ethyl* at 13 (footnotes omitted).

Similarly, the court stated that ''[i]n sum, based on the plain meaning of the statute, the juxtaposition of CAA section 211 with CAA sections 108 and 202, and the *Reserve Mining* precedent, we conclude that the ''will endanger'' standard is precautionary in nature and does not require proof of actual harm before regulation is appropriate.'' *Ethyl* at 17. It is this authority to act before harm has occurred that makes it a preventive, precautionary provision.

It is important to note that this statement was in the context of rejecting an argument that EPA had to prove actual harm before it could adopt fuel control regulations under then CAA section 211(c)(1). The court likewise rejected the argument that EPA had to show that such harm was ''probable.''

The court made it clear that determining endangerment entails judgments involving both the risk or likelihood of harm and the severity of the harm if it were to occur. Nowhere did the court indicate that the burden was on the opponents of an endangerment finding to show that there was no endangerment. The opinion focuses on describing the burden the statute places on EPA, rejecting *Ethyl's* arguments of a burden to show actual or probable harm.

Congress intentionally adopted a precautionary and preventive approach. It stated that the purpose of the 1977 amendments was to ''emphasize the preventive or precautionary nature of the act, *i.e.,* to assure that regulatory action can effectively prevent harm before it occurs; to emphasize the predominate value of protection to public health.'' [6] Congress also stated that it authorized the Administrator to weigh risks and make projections of future trends, a ''middle road between those who would impose a nearly impossible standard of proof on the Administrator before he may move to protect public health and those who would shift the burden of proof for all pollutants to make the pollutant source prove the safety of its emissions as a condition of operation.'' Leg. His. at 2516.

Thus, EPA rejects commenters' arguments. Congress intended this provision to be preventive and precautionary in nature, however it did not shift the burden of proof to opponents of an endangerment finding to show safety or no endangerment. Moreover, as is demonstrated in the following, EPA has not shifted the burden of proof in the final endangerment finding, but rather is weighing the likelihood and severity of harms to arrive at the final finding. EPA has not applied an exaggerated or dramatically expanded precautionary principle, and instead has exercised judgment by weighing and balancing the factors that are relevant under this provision.

b. The Administrator Does Not Need To Find That the Control Measures Following an Endangerment Finding Would Prevent at Least a Substantial Part of the Danger in Order To Find Endangerment

Several commenters argue that it is unlawful for EPA to make an affirmative endangerment finding unless EPA finds that the regulatory control measures contemplated to follow such a finding would prevent at least a substantial part of the danger from the global climate change at which the regulation is aimed. This hurdle is also described by commenters as the regulation ''achieving the statutory objective of preventing damage'', or ''fruitfully attacking'' the environmental and public health danger at hand by meaningfully and substantially reducing it. Commenters point to *Ethyl Corp.* v. *EPA,* 541 F.2d 1 (DC Cir. 1976) (en banc) as support for this view, as well as portions of the legislative history of this provision.

Commenters contend that EPA has failed to show that this required degree of meaningful reduction of endangerment would be achieved through regulation of new motor vehicles based on an endangerment finding. In making any such showing, commenters argue that EPA would need to account for the following: (1) The fact that any regulation would be limited to *new* motor vehicles, if not the subset of new motor vehicles discussed in the President's May 2009 announcement, (2) any increase in emissions from purchasers delaying purchases of new vehicles subject to any greenhouse gas emissions standards, or increasing the miles traveled of new vehicles with greater fuel economy, (3) the fact that only a limited portion of the new motor vehicle emissions of greenhouse gases would be controlled, (4) the fact that CAFE standards would effectively achieve the same reductions, and (5) the fact that any vehicle standards would not themselves reduce global temperatures. Some commenters refer to EPA's proposal for greenhouse gas emissions standards for new motor vehicles as support for these arguments, claiming the proposed new motor vehicle emission standards are largely duplicative of the standards proposed by the National Highway Traffic Safety Administration (NHTSA), and the estimates of the impacts of the proposed standards confirm that EPA's proposed standards cannot ''fruitfully attack'' global climate change (74 FR 49454, September 28, 2009).

Commenters attempt to read into the statute a requirement that is not there. EPA interprets the endangerment provision of CAA section 202(a) as not requiring any such finding or showing as described by commenters. The text of CAA section 202(a) does not support such an interpretation. The endangerment provision calls for EPA, in its judgment, to determine whether air pollution is reasonably anticipated to endanger public health or welfare, and whether emissions from certain sources cause or contribute to such air pollution. If EPA makes an affirmative finding, then it shall set emissions standards applicable to emissions of such air pollutants from new motor vehicles. There is no reference in the text of the endangerment or cause or contribute provision to anything concerning the degree of reductions that would be achieved by the emissions standards that would follow such a finding. The Administrator's judgment is directed at the issues of endangerment and cause or contribute, not at how effective the resulting emissions control standards will be.

As in the several other similar provisions adopted in the 1977 amendments, in CAA section 202(a) Congress explicitly separated two different decisions to be made, providing different criteria for them. The first decision involves the air pollution and the endangerment criteria, and the contribution to the air pollution by the sources. The second decision involves how to regulate the sources to control the emissions if an affirmative endangerment and contribution finding are made. In all of the various provisions, there is broad similarity in the phrasing of the endangerment and contribution decision. However, for the decision on how to regulate, there are a wide variety of different approaches adopted by Congress. In some case, EPA has discretion whether to issue standards or not, while in other cases, as in CAA section 202(a), EPA is required to issue standards. In some cases, the regulatory criteria are general, as in CAA section 202(a); in others, they provide significantly more direction as to how standards are to be set, as in CAA section 213(a)(4).

As the Supreme Court made clear in *Massachusetts* v. *EPA,* EPA's judgment in making the endangerment and contribution findings is constrained by the statute, and EPA is to decide these issues based solely on the scientific and other evidence relevant to that decision. EPA may not ''rest[] on reasoning divorced from the statutory text,'' and instead EPA's exercise of judgment must relate to whether an air pollutant causes or contributes to air pollution that endangers. *Massachusetts* v. *EPA,* 549 U.S. at 532. As the Supreme Court noted, EPA must ''exercise discretion within defined statutory limits.'' Id. at 533. EPA's belief one way or the other regarding whether regulation of greenhouse gases from new motor vehicles would be ''effective'' is irrelevant in making the endangerment and contribution decisions before EPA. Id. Instead ''[t]he statutory question is

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[6] The Supreme Court recognized that the current language in section 202(a), adopted in 1977, is ''more protective'' than the 1970 version that was similar to the section 211 language before the DC Circuit in *Ethyl. Massachusetts* v. *EPA,* 549 U.S. at 506, fn 7.

whether sufficient information exists to make an endangerment finding'' Id. at 534.

The effectiveness of a potential future control strategy is not relevant to deciding whether air pollution levels in the atmosphere endanger. It is also not relevant to deciding whether emissions of greenhouse gases from new motor vehicles contribute to such air pollution. Commenters argue that Congress implicitly imposed a third requirement, that the future control strategy have a certain degree of effectiveness in reducing the endangerment before EPA could make the affirmative findings that would authorize such regulation. There is no statutory text that supports such an interpretation, and the Supreme Court makes it clear that EPA has no discretion to read this kind of additional factor into CAA section 202(a)'s endangerment and contribution criteria. In fact, the Supreme Court rejected similar arguments that EPA had the discretion to consider various other factors besides endangerment and contribution in deciding whether to deny a petition. *Massachusetts* v. *EPA,* 549 U.S. at 532–35.

Commenters point to language from the *Ethyl* case to support their position, noting that the DC Circuit referred to the emissions control regulation adopted by EPA under CAA section 211(c) as one that would ''fruitfully attack'' the environmental and public health danger by meaningfully and substantially reducing the danger. It is important to understand the context for this discussion in *Ethyl.* The petitioner *Ethyl Corp.* argued that EPA had to show that the health threat from the emissions of lead from the fuel additive being regulated had to be considered in isolation, and the threat ''in and of itself'' from the additive had to meet the test of endangerment in CAA section 211(c). EPA had rejected this approach, and had interpreted CAA section 211(c)(1) as calling for EPA to look at the cumulative impact of lead, and to consider the impact of lead from emissions related to use of the fuel additive in the context all other human exposure to lead. The court rejected *Ethyl's* approach and supported EPA's interpretation. The DC Circuit noted that Congress was fully aware that the burden of lead on the body was caused by multiple sources and that it would be of no value to try and determine the effect on human health from the lead automobile emissions by themselves. The court specifically noted that ''the incremental effect of lead emissions on the total body lead burden is of no practical value in determining whether health is endangered,'' but recognized that this incremental effect is of value ''in deciding whether the lead exposure problem can fruitfully be attacked through control of lead additives.'' *Ethyl,* 541 F.2d at 31 fn 62. The court made clear that the factor that was critically important to determining the effectiveness of the resulting control strategy—the incremental effect of automobile lead emissions on total body burden—was irrelevant and of no value in determining whether the endangerment criteria was met. Thus it is clear that the court in *Ethyl* did not interpret then CAA section 211(c)(1)(A) as requiring EPA to make a showing of the effectiveness of the resulting emissions control strategy, and instead found just the opposite, that the factors that would determine effectiveness are irrelevant to determining endangerment.

Commenters also cite to the legislative history, noting that Congress referred to the ''preventive or precautionary nature of the Act, *i.e.,* to assure that regulatory action can effectively prevent harm before it occurs.'' Leg. Hist. at 2516. However, this statement by Congress is presented as an answer to the question on page 2515, ''Should the Administrator act to prevent harm before it occurs or should he be authorized to regulate an air pollutant only if he finds actual harm has already occurred.'' Leg. Hist. at 2515. In this context, the discussion on page 2516 clearly indicates that there is no opportunity for prevention or precaution if the test is one of actual harm already occurring. This discussion does not say or imply that even if the harm has not occurred, you can not act unless you also show that your action will effectively address it. This discussion concerns the endangerment test, not the criteria for standard setting. The criteria for standard setting address how the agency should act to address the harm, and as the *Ethyl* case notes, the factors relevant to how to ''fruitfully attack'' the harm are irrelevant to determining whether the harm is one that endangers the public health or welfare.

As with current CAA section 202(a), there is no basis to conflate these two separate decisions and to read into the endangerment criteria an obligation that EPA show that the resulting emissions control strategy or strategies will have some significant degree of harm reduction or effectiveness in addressing the endangerment. The conflating of the two decisions is not supported in the text of this provision, by the Supreme Court in *Massachusetts* v. *EPA,* by the DC Circuit in *Ethyl,* or by Congress in the legislative history of this provision. It would be an unworkable interpretation, calling for EPA to project out the result of perhaps not one, but even several, future rulemakings stretching over perhaps a decade or decades. Especially in the context of global climate change, the effectiveness of a control strategy for new motor vehicles would have to be viewed in the context of a number of future motor vehicle regulations, as well as in the larger context of the CAA and perhaps even global context. That would be an unworkable and speculative requirement to impose on EPA as a precondition to answering the public health and welfare issues before it, as they are separate and apart from the issues involved with developing, implementing and evaluating the effectiveness of emissions control strategies.

c. The Administrator Does Not Need To Find There Is Significant Risk of Harm

Commenters argue that Congress established a minimum requirement that there be a ''significant risk of harm'' to find endangerment. They contend that this requirement stemmed from the *Ethyl* case, and that Congress adopted this view. According to the commenters, the risk is the function of two variables: the nature of the hazard at issue and the likelihood of its occurrence. Commenters argue that Congress imposed a requirement that this balance demonstrate a ''significant risk of harm'' to strike a balance between the precautionary nature of the CAA and the burdensome economic and societal consequences of regulation.

There are two basic problems with the commenters' arguments. First, commenters equate ''significant risk of harm'' as the overall test for endangerment, however the *Ethyl* case and the legislative history treat the risk of harm as only one of the two components that are to be considered in determining endangerment.—, The two components are the likelihood or risk of a harm occurring, and the severity of harm if it were to occur. Second, commenters equate it to a minimum statutory requirement. However, while the court in the *Ethyl* case made it clear that the facts in that case met the then applicable endangerment criteria, it also clearly said it was not determining what other facts or circumstances might amount to endangerment, including cases where the likelihood of a harm occurring was less than a significant risk of the harm.

In the EPA rulemaking that led to the *Ethyl* case, EPA stated that the requirement to reduce lead in gasoline ''is based on the finding that lead particle emissions from motor vehicles present a significant risk of harm to the health of urban populations, particularly to the health of city children'' (38 FR 33734, December 6, 1973). The court in *Ethyl* supported EPA's determination, and addressed a variety of issues. First, it determined that the ''will endanger'' criteria of then CAA section 211(c) was intended to be precautionary in nature. It rejected arguments that EPA had to show proof of actual harm, or probable harm. *Ethyl,* 541 F.2d at 13–20. It was in this context, evaluating petitioner's arguments on whether the likelihood of a harm occurring had to rise to the level of actual or probable harm, that the court approved of EPA's view that a significant risk of harm could satisfy the statutory criteria. The precautionary nature of the provision meant that EPA did not need to show that either harm was actually occurring or was probable.

Instead, the court made it clear that the concept of endangerment is ''composed of reciprocal elements of risk and harm,'' *Ethyl* at 18. This means ''the public health may properly be found endangered both by a lesser risk of a greater harm and by a greater risk of lesser harm. Danger depends upon the relation between the risk and harm presented by each case, and cannot legitimately be pegged to 'probable' harm, regardless of whether that harm be great or small.'' The Ethyl court pointed to the decision by the 8th Circuit in *Reserve Mining Co.* v. *EPA,* 514 F.2d 492 (8th Cir, 1975), which interpreted similar language under the Federal Water Pollution Control Act, where the 8th Circuit upheld an endangerment finding in a case involving ''reasonable medical concern,'' or a ''potential'' showing of harm. This was further evidence that a minimum ''probable'' likelihood of harm was not required.

The Ethyl court made it clear that there was no specific magnitude of risk of harm occurring that was required. ''Reserve Mining convincingly demonstrates that the magnitude of risk sufficient to justify regulation is inversely proportional to the harm to be avoided.'' *Ethyl* at 19. This means there is no minimum requirement that the magnitude of risk be ''significant'' or another specific level of likelihood of occurrence. You need to evaluate the risk of harm in the context of the severity of the harm if it were to occur. In the case before it, the Ethyl court noted that ''the harm caused by lead poisoning is severe.'' Even with harm as severe as lead poisoning, EPA did not rely on ''potential'' risk or a ''reasonable medical concern.'' Instead, EPA found that there was a significant risk of this harm to health. This finding of a significant risk was less than the level of ''probable'' harm called for by the petitioner Ethyl Corporation but was ''considerably more certain than the risk that justified regulation in Reserve Mining of a comparably 'fright-laden' harm.'' *Ethyl* at 19–20. The Ethyl court concluded that this combination of risk (likelihood of harm) and severity of harm was sufficient under CAA section 211(c). ''Thus we conclude that however far the parameters of risk and harm inherent in the 'will endanger' standard might reach in an appropriate case, they certainly present a 'danger' that can be regulated when the harm to be avoided is widespread lead poisoning and the risk of that occurrence is 'significant'.'' *Ethyl* at 20.

Thus, the court made it clear that the endangerment criteria was intended to be precautionary in nature, that the risk of harm was one of the elements to consider in determining endangerment, and that the risk of harm needed to be considered in the context of the severity of the potential harm. It also concluded that a significant risk of harm coupled with an appropriate severity of the potential harm would satisfy the statutory criteria, and in the case before it the Administrator was clearly authorized to determine endangerment where there was a significant risk of harm that was coupled with a severe harm such as lead poisoning.

Importantly, the court also made it clear that it was not determining a minimum threshold that always had to be met. Instead, it emphasized that the risk of harm and severity of the potential harm had to be evaluated on a case by case basis. The court specifically said it was not determining ''however far the parameters of risk and harm * * * might reach in an appropriate case.'' *Ethyl* at 20. Also see *Ethyl* fn 17 at 13. The court recognized that this balancing of risk and harm ''must be confined to reasonable limits'' and even absolute certainty of a de minimis harm might not justify government action. However, ''whether a particular combination of slight risk and great harm, or great risk and slight harm constitutes a danger must depend on the facts of each case.'' *Ethyl* at fn 32 at 18.[7]

In some cases, commenters confuse matters by switching the terminology, and instead refer to effects that ''significantly harm'' the public health or welfare. As with the reference to ''significant risk of harm,'' commenters fail to recognize that there are two different aspects that must be considered, risk of harm and severity of harm, and neither of these aspects has a requirement that there be a finding of ''significance.'' The DC Circuit in *Ethyl* makes clear that it is the combination of these two aspects that must be evaluated for purposes of endangerment, and there is no requirement of ''significance'' assigned to either of the two aspects that must instead be evaluated in combination. Congress addressed concerns over burdensome economic and societal consequences in the various statutory provisions that provide the criteria for standard setting or other agency action if there is an affirmative endangerment finding. Those statutory provisions, for example, make standard setting discretionary or specify how cost and other factors are to be taken into consideration in setting standards. However, the issues of risk of harm and severity of harm if it were to occur are separate from the issues of the economic impacts of any resulting regulatory provisions (*see* below).

As is clear in the prior summary of the endangerment findings and the more detailed discussion later, the breadth of the sectors of our society that are affected by climate change and the time frames at issue mean there is a very wide range of risks and harms that need to be considered, from evidence of various harms occurring now to evidence of risks of future harms. The Administrator has determined that the body of scientific evidence compellingly supports her endangerment finding.

B. Air Pollutant, Public Health and Welfare

The CAA defines both ''air pollutant'' and ''effects on welfare.'' We provide both definitions here again for convenience.

Air pollutant is defined as:

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[7] Commenters point to *Amer. Farm Bureau Ass'n* v. *EPA,* 559 F.3d 512, 533 (DC Cir. 2009) as supporting their argument. However, in that case the Court made clear that EPA's action was not subject to the endangerment criterion in CAA section 108 but instead was subject to CAA section 109's requirement that the primary NAAQS be requisite to protect the public health with an adequate margin of safety. Under that provision and its case law, the Court upheld EPA's reasoned balancing of the uncertainty regarding the link between non-urban thoracic coarse PM and adverse health effects, the large population groups potentially exposed to these particles, and the nature and degree of the health effects at issue. Citing to EPA's reasoning at 71 FR 61193 in the final PM rule, the court explained that EPA need not wait for conclusive proof of harm before setting a NAAQS under section 109 for this kind of coarse PM. The Court's reference to EPA's belief that there may be a significant risk to public health is not stated as any sort of statutory minimum, but instead refers to the Agency's reasoning at 71 FR 61193, which displays a reasoned balancing of possibility of harm and severity of harm if it were to occur.

''Any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term ''air pollutant'' is used.'' CAA section 302(g). As the Supreme Court held, greenhouse gases fit well within this capacious definition. *See Massachusetts* v. *EPA,* 549 U.S. at 532. They are ''without a doubt'' physical chemical substances emitted into the ambient air. *Id.* at 529.

''Regarding 'effects on welfare', the CAA states that [a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants.'' CAA section 302(h).

As noted in the Proposed Findings, this definition is quite broad. Importantly, it is not an exclusive list due to the use of the term ''includes, but is not limited to, * * * .'' Effects other than those listed here may also be considered effects on welfare. Moreover, the terms contained within the definition are themselves expansive.

Although the CAA defines ''effects on welfare'' as discussed above, there are no definitions of ''public health'' or ''public welfare'' in the CAA. The Supreme Court has discussed the concept of public health in the context of whether costs of implementation can be considered when setting the health based primary National Ambient Air Quality Standards. *Whitman v. American Trucking Ass'n,* 531 U.S. 457 (2001). In *Whitman,* the Court imbued the term with its most natural meaning: ''the health of the public. *Id.* at 466. In the past, when considering public health, EPA has looked at morbidity, such as impairment of lung function, aggravation of respiratory and cardiovascular disease, and other acute and chronic health effects, as well as mortality. *See, e.g., Final National Ambient Air Quality Standard for Ozone,* (73 FR 16436, 2007).

EPA received numerous comments regarding its proposed interpretations of air pollutant and public health and welfare. Summaries of key comments and EPA's responses are discussed in Sections IV and V of these Findings. Additional and more detailed summaries and responses can be found in the Response to Comments document. As noted in the Response to Comments document, EPA also received comments supporting its legal interpretations.

III. EPA's Approach for Evaluating the Evidence Before It

This section discusses EPA's approach to evaluating the evidence before it, including the approach taken to the scientific evidence, the legal framework for this decision making, and several issues critical to determining the scope of the evaluation performed.

A. The Science on Which the Decisions Are Based

In 2007, EPA initiated its assessment of the science and other technical information to use in addressing the endangerment and cause or contribute issues before it under CAA section 202(a). This scientific and technical information was developed in the form of a TSD in 2007. An earlier draft of this document was released as part of the ANPR published July 30, 2008 (73 FR 44353). That earlier draft of the TSD relied heavily on the IPCC Fourth Assessment Report of 2007, key NRC reports, and a limited number of then-available synthesis and assessment products of the U.S. Climate Change Science Program (CCSP; now encompassed by USGCRP). EPA received a number of comments specifically focused on the TSD during the 120-day public comment period for the ANPR.

EPA revised and updated the TSD in preparing the Proposed Findings on endangerment and cause or contribute. Many of the comments received on the ANPR were reflected in the draft TSD released in April 2009 that served as the underlying scientific and technical basis for the Administrator's Proposed Findings, published April 24, 2009 (74 FR 18886). The draft TSD released in April 2009 also reflected the findings of 11 new synthesis and assessment products under the U.S. CCSP that had been published since July 2008.

The TSD that summarizes scientific findings from the major assessments of the USGCRP, the IPCC, and the NRC accompanies these Findings. The TSD is available at *www.epa.gov/climatechange/endangerment.html* and in the docket for this action. It also includes the most recent comprehensive assessment of the USGCRP, *Global Climate Change Impacts in the United States,*[8] published in June 2009. In addition, the TSD incorporates up-to-date observational data for a number of key climate variables from the NOAA, and the most up-to-date emissions data from EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* published in April, 2009.[9] And finally, as discussed in Section I.B of these Findings, EPA received a large number of public comments on the Administrator's Proposed Findings, many of which addressed science issues either generally or specifically as reflected in the draft TSD released with the April 2009 proposal. A number of edits and updates were made to the draft TSD as a result of these comments.[10]

EPA is giving careful consideration to all of the scientific and technical information in the record, as discussed below. However, the Administrator is relying on the major assessments of the USGCRP, IPCC, and NRC as the primary scientific and technical basis of her endangerment decision for a number of reasons.

First, these assessments address the scientific issues that the Administrator must examine for the endangerment analysis. When viewed in total, these assessments address the issue of greenhouse gas endangerment by providing data and information on: (1) The amount of greenhouse gases being emitted by human activities; (2) how greenhouse gases have been and continue to accumulate in the atmosphere as a result of human activities; (3) changes to the Earth's energy balance as a result of the buildup of atmospheric greenhouse gases; (4) observed temperature and other climatic changes at the global and regional scales; (5) observed changes in other climate-sensitive sectors and systems of the human and natural environment; (6) the extent to which observed climate change and other changes in climate-sensitive systems can be attributed to the human-induced buildup of atmospheric greenhouse gases; (7) future projected climate change under a range of different scenarios of changing greenhouse gas emission rates; and (8) the projected risks and impacts to

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[8] Karl, T., J. Melillo, and T. Peterson (Eds.) (2009) Global Climate Change Impacts in the United States. Cambridge University Press, Cambridge, United Kingdom.

[9] U.S. EPA (2009) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007.* EPA–430–R–09–004, Washington, DC.

[10] EPA has placed within the docket a separate memo ''Summary of Major Changes to the Technical Support Document'' identifying where within the TSD such changes were made relative to the draft TSD released in April 2009.

human health, society and the environment.

Second, as indicated above, these assessments are recent and represent the current state of knowledge on the key elements for the endangerment analysis. It is worth noting that the June 2009 assessment of the USGCRP incorporates a number of key findings from the 2007 IPCC Fourth Assessment Report; such findings include the attribution of observed climate change to human emissions of greenhouse gases, and the future projected scenarios of climate change for the global and regional scales. This demonstrates that much of the underlying science that EPA has been utilizing since 2007 has not only been in the public domain for some time, but also has remained relevant and robust.

Third, these assessments are comprehensive in their coverage of the greenhouse gas and climate change problem, and address the different stages of the emissions-to-potential-harm chain necessary for the endangerment analysis. In so doing, they evaluate the findings of numerous individual peer-reviewed studies in order to draw more general and overarching conclusions about the state of science. The USGCRP, IPCC, and NRC assessments synthesize literally thousands of individual studies and convey the consensus conclusions on what the body of scientific literature tells us.

Fourth, these assessment reports undergo a rigorous and exacting standard of peer review by the expert community, as well as rigorous levels of U.S. government review and acceptance. Individual studies that appear in scientific journals, even if peer reviewed, do not go through as many review stages, nor are they reviewed and commented on by as many scientists. The review processes of the IPCC, USGCRP, and NRC (explained in fuller detail in the TSD and the Response to Comments document, Volume 1) provide EPA with strong assurance that this material has been well vetted by both the climate change research community and by the U.S. government. These assessments therefore essentially represent the U.S. government's view of the state of knowledge on greenhouse gases and climate change. For example, with regard to government acceptance and approval of IPCC assessment reports, the USGCRP Web site states that: ''When governments accept the IPCC reports and approve their Summary for Policymakers, they acknowledge the legitimacy of their scientific content.'' [11] It is the Administrator's view that such review and acceptance by the U.S. Government lends further support for placing primary weight on these major assessments.

It is EPA's view that the scientific assessments of the IPCC, USGRCP, and the NRC represent the best reference materials for determining the general state of knowledge on the scientific and technical issues before the agency in making an endangerment decision. No other source of information provides such a comprehensive and in-depth analysis across such a large body of scientific studies, adheres to such a high and exacting standard of peer review, and synthesizes the resulting consensus view of a large body of scientific experts across the world. For these reasons, the Administrator is placing primary and significant weight on these assessment reports in making her decision on endangerment.

A number of commenters called upon EPA to perform a new and independent assessment of all of the underlying climate change science, separate and apart from USGCRP, IPCC, and NRC. In effect, commenters suggest that EPA is either required to or should ignore the attributes discussed above concerning these assessment reports, and should instead perform its own assessment of all of the underlying studies and information.

In addition to the significant reasons discussed above for relying on and placing primary weight on these assessment reports, EPA has been a very active part of the U.S. government climate change research enterprise, and has taken an active part in the review, writing, and approval of these assessments. EPA was the lead agency for three significant reports under the USGCRP [12], and recently completed an assessment addressing the climate change impacts on U.S. air quality—a report on which the TSD heavily relies for that particular issue. EPA was also involved in review of the IPCC Fourth Assessment Report, and in particular took part in the approval of the summary for policymakers for the Working Group II Volume, *Impacts, Adaptation and Vulnerability.*[13] The USGCRP, IPCC, and NRC assessments have been reviewed and formally accepted by, commissioned by, or in some cases authored by, U.S. government agencies and individual government scientists. These reports already reflect significant input from EPA's scientists and the scientists of many other government agencies.

EPA has no reason to believe that the assessment reports do not represent the best source material to determine the state of science and the consensus view of the world's scientific experts on the issues central to making an endangerment decision with respect to greenhouse gases. EPA also has no reason to believe that putting this significant body of work aside and attempting to develop a new and separate assessment would provide any better basis for making the endangerment decision, especially because any such new assessment by EPA would still have to give proper weight to these same consensus assessment reports.

In summary, EPA concludes that its reliance on existing and recent synthesis and assessment reports is entirely reasonable and allows EPA to rely on the best available science.[14] EPA also recognizes that scientific research is very active in many areas addressed in the TSD (*e.g.,* aerosol effects on climate, climate feedbacks such as water vapor, and internal and external climate forcing mechanisms), as well as for some emerging issues (*e.g.,* ocean acidification and climate change effects on water quality). EPA recognizes the potential importance of new scientific research, and the value of an ongoing process to take more recent science into account. EPA reviewed new literature in

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[11] *http://www.globalchange.gov/publications/reports/ipcc-reports.*

[12] CCSP (2009) *Coastal Sensitivity to Sea-Level Rise: A Focus on the Mid-Atlantic Region.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [James G. Titus (Coordinating Lead Author), K. Eric Anderson, Donald R. Cahoon, Dean B. Gesch, Stephen K. Gill, Benjamin T. Gutierrez, E. Robert Thieler, and S. Jeffress Williams (Lead Authors)], U.S. Environmental Protection Agency, Washington DC, USA, 320 pp. CCSP (2008) *Preliminary review of adaptation options for climate-sensitive ecosystems and resources.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Julius, S.H., J.M. West (eds.), J.S. Baron, B. Griffith, L.A. Joyce, P. Kareiva, B.D. Keller, M.A. Palmer, C.H. Peterson, and J.M. Scott (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA, 873 pp. CCSP (2008) *Analyses of the effects of global change on human health and welfare and human systems.* A Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. [Gamble, J.L. (ed.), K.L. Ebi, F.G. Sussman, T.J. Wilbanks, (Authors)]. U.S. Environmental Protection Agency, Washington, DC, USA.

[13] IPCC (2007) Climate Change 2007: *Impacts, Adaptation and Vulnerability.* Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, M.L. Parry, O.F. Canziani, J.P. Palutikof, P.J. van der Linden and C.E. Hanson, Eds., Cambridge University Press, Cambridge, UK, 976pp.

[14] It maintains the highest level of adherence to Agency and OMB guidelines for data and scientific integrity and transparency. This is discussed in greater detail in EPA's Response to Comments document.

preparation of this TSD to evaluate its consistency with recent scientific assessments. We also considered public comments received and studies incorporated by reference. In a number of cases, the TSD was updated based on such information to add context for assessment literature findings, which includes supporting information and/or qualifying statements. In other cases, material that was not incorporated into the TSD is discussed within the Response to Comments document.

EPA reviewed these individual studies that were not considered or reflected in these major assessments to evaluate how they inform our understanding of how greenhouse gas emissions affect climate change, and how climate change may affect public health and welfare. Given the very large body of studies reviewed and assessed in developing the assessment reports, and the rigor and breadth of that review and assessment, EPA placed limited weight on the much smaller number of individual studies that were not considered or reflected in the major assessments. EPA reviewed them largely to see if they would lead EPA to change or place less weight on the judgments reflected in the assessment report. While EPA recognizes that some studies are more useful or informative than others, and gave each study it reviewed the weight it was due, the overall conclusion EPA drew from its review of studies submitted by commenters was that the studies did not change the various conclusions or judgments EPA would draw based on the assessment reports.

Many comments focus on the scientific and technical data underlying the Proposed Findings, such as climate change science and greenhouse gas emissions data. These comments cover a range of topics and are summarized and responded to in the Response to Public Comments document. The responses note those cases where a technical or scientific comment resulted in an editorial or substantive change to the TSD. The final TSD reflects all changes made as a result of public comments.

B. The Law on Which the Decisions Are Based

In addition to grounding these determinations on the science, they are also firmly grounded in EPA's legal authority. Section II of these Findings provides an in-depth discussion of the legal framework for the endangerment and cause or contribute decisions under CAA section 202(a), with additional discussion in Section II of the Proposed Finding (74 FR 18886, 18890, April 24, 2009). A variety of important legal issues are also discussed in Sections III, IV, and V of these Findings, as well as in the Response to Comments document, Volume 11. Section IV and V of these Findings explain the Administrator's decisions, and how she exercised her judgment in making the endangerment and contribution determinations, based on the entire scientific record before her and the legal framework structuring her decision making.

C. Adaptation and Mitigation

Following the language of CAA section 202(a), in which the Administrator, in her judgment, must determine if greenhouse gases constitute the air pollution that may be reasonably anticipated to endanger public health or welfare, EPA evaluated, based primarily on the scientific reports discussed above, how greenhouse gases and other climate-relevant substances are affecting the atmosphere and climate, and how these climate changes affect public health and welfare, now and in the future. Consistent with EPA's scientific approach underlying the Administrator's Proposed Findings, EPA did not undertake a separate analysis to evaluate potential societal and policy responses to any threat (*i.e.,* the endangerment) that may exist due to anthropogenic emissions of greenhouse gases. Risk reduction through adaptation and greenhouse gas mitigation measures is of course a strong focal area of scientists and policy makers, including EPA; however, EPA considers adaptation and mitigation to be potential responses to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.

The Administrator's position is not that adaptation will not occur or cannot help protect public health and welfare from certain impacts of climate change, as some commenters intimated. To the contrary, EPA recognizes that some level of autonomous adaptation[15] will occur, and commenters are correct that autonomous adaptation can affect the severity of climate change impacts. Indeed, there are some cases in the TSD in which some degree of adaptation is accounted for; these cases occur where the literature on which the TSD relies already uses assumptions about autonomous adaptation when projecting the future effects of climate change. Such cases are noted in the TSD. We also view planned adaptation as an important near-term risk-minimizing strategy given that some degree of climate change will continue to occur as a result of past and current emissions of greenhouse gases that remain in the atmosphere for decades to centuries.

However, it is the Administrator's position that projections of adaptation and mitigation in response to risks and impacts associated with climate change are not appropriate for EPA to consider in making a decision on whether the air pollution endangers. The issue before EPA involves evaluating the risks to public health and welfare from the air pollution if we do not take action to address it. Adaptation and mitigation address an important but different issue—how much risk will remain assuming some projection of how people and society will respond to the threat.

Several commenters argue that it is arbitrary not to consider adaptation in determining endangerment. They contend that because endangerment is a forward-looking exercise, the fundamental inquiry concerns the type and extent of harm that is believed likely to occur in the future. Just as the Administrator makes projections of potential harms in the future, these commenters contend that the Administrator needs to consider the literature on adaptation that addresses the likelihood and the severity of potential effects. Commenters also note that since adaption is one of the likely impacts of climate change, it is irrational to exclude it from consideration when the goal is to evaluate the risks and harms in the real world in the future, not the risks and harms in the hypothetical scenario that result if you ignore adaptation.

According to commenters, the Administrator must consider both autonomous adaptation and anticipatory adaptation. They contend that literature on adaptation makes it clear there is a significant potential for adaptation, and that it can reduce the likelihood or severity of various effects, including health effects, and could even avert what might otherwise constitute endangerment. Commenters note that EPA considered the adaptation of species in nature, and it is arbitrary to not also consider adaptation by humans. Moreover, they argue that there is great

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[15] The IPCC definition of adaptation: ''Adaptation to climate change takes place through adjustments to reduce vulnerability or enhance resilience in response to observed or expected changes in climate and associated extreme weather events. Adaptation occurs in physical, ecological and human systems. It involves changes in social and environmental processes, perceptions of climate risk, practices and functions to reduce potential damages or to realize new opportunities.'' The IPCC defines autonomous adaptation as ''Adaptation that does not constitute a conscious response to climatic stimuli but is triggered by ecological changes in natural systems and by market or welfare changes in human systems.''

certainty that adaptation will occur, and thus EPA is required to address it and make projections. They recommend that EPA look to historic responses to changes in conditions as an analogue in making projections, recognizing that life in the United States is likely to be quite different 50 or 100 years from now, irrespective of climate change.

Commenters argue that adaption needs to be considered because it is central to the statutory requirements governing the endangerment inquiry. EPA is charged to determine the type and extent of harms that are likely to occur, and they argue that this can not rationally be considered without considering adaptation. Since some degree of adaptation is likely to occur, they continue that such a projection of future actual conditions requires consideration of adaption to evaluate whether the future conditions amount to endangerment from the air pollution.

According to commenters, the issue therefore is focused on human and societal adaptation, which can come in a wide variety of forms, ranging from changes in personal behavioral patterns to expenditures of resources to change infrastructure, such as building and maintaining barriers to protect against sea level rise.

With regard to mitigation, commenters argue that EPA should consider mitigation strategies and their potential to alleviate harm from greenhouse gas emissions. They contend that it is unreasonable for EPA to assume that society will not undertake mitigation.

Section 202(a) of the CAA reflects the basic approach of many CAA sections—the threshold inquiry is whether the endangerment and cause or contribute criteria are satisfied, and only if they are met do the criteria for regulatory action go into effect. This reflects the basic separation of two different decisions—is this a health and welfare problem that should be addressed, and if so what are the appropriate mechanisms to address it? There is a division between identifying the health and welfare problem associated with the air pollution, and identifying the mechanisms used to address or solve the problem.

In evaluating endangerment, EPA is determining whether the risks to health and welfare from the air pollution amount to endangerment. As commenters recognize, that calls for evaluating and projecting the nature and types of risks from the air pollution, including the probability or likelihood of the occurrence of an impact and the degree of adversity (or benefit) of such an impact. This issue focuses on how EPA makes such an evaluation in determining endangerment—does EPA look at the risks assuming no planned adaptation and/or mitigation, although EPA projects some degree is likely to occur, or does EPA look at the risks remaining after some projection of adaptation and/or mitigation?

These two approaches reflect different views of the core question EPA is trying to answer. The first approach most clearly focuses on just the air pollution and its impacts, and aims to separate this from the human and societal responses that may or should be taken in response to the risks from the air pollution. By its nature, this separation means this approach may not reflect the actual conditions in the real world in the future, because adaptation and/or mitigation may occur and change the risks. For example, adaptation would not change the atmospheric concentrations, or the likelihood or probability of various impacts occurring (*e.g.*, it would not change the degree of sea level rise), but adaptation has the potential to reduce the adversity of the effects that do occur from these impacts. Mitigation could reduce the atmospheric concentrations that would otherwise occur, having the potential to reduce the likelihood or probability of various impacts occurring. Under this approach, the evaluation of risk is focused on the risk if we do not address the problem. It does not answer the question of how much risk we project will remain after we do address the problem, through either adaptation or mitigation or some combination of the two.

The second approach, suggested by commenters, would call for EPA to project into the future adaptation and/or mitigation, and the effect of these measures in reducing the risks to health or welfare from the air pollution. Commenters argue this will better reflect likely real world conditions, and therefore is needed to allow for an appropriate determination of whether EPA should, at this time, make an affirmative endangerment finding. However, this approach would not separate the air pollution and its impacts from the human and societal responses to the air pollution. It would intentionally and inextricably intertwine them. It would inexorably change the focus from how serious is the air pollution problem we need to address to how good a job are people and society likely to do in addressing or solving the problem. In addition it would dramatically increase the complexity of the issues before EPA.

The context for this endangerment finding is a time span of several decades into the future. It involves a wide variety of differing health and welfare effects, and almost every sector in our society. This somewhat unique context tends to amplify the differences between the two different approaches. It also means that it is hard to cleanly implement either approach. For example, it is hard under the first approach to clearly separate impacts with and without adaption, given the nature of the scientific studies and information before us. Under the second approach it would be extremely hard to make a reasoned projection of human and societal adaptation and mitigation responses, because these are basically not scientific or technical judgments, but are largely political judgments for society or individual personal judgments.

However, the context for this endangerment finding does not change the fact that at their core the two different approaches are aimed at answering different questions. The first approach is focused on answering the question of what are the risks to public health and welfare from the air pollution if we do not take action to address it. The second approach is focused on answering the question of how much risk will remain assuming some projection of how people and society will respond.

EPA believes that it is appropriate and reasonable to interpret CAA section 202(a) as calling for the first approach. The structure of CAA section 202(a) and the various other similar provisions indicate an intention by Congress to separate the question of what is the problem we need to address from the question of what is the appropriate way to address it. The first approach is clearly more consistent with this statutory structure. The amount of reduction in risk that might be achieved through adaptation and/or mitigation is closely related to the way to address a problem, and is not focused on what is the problem that needs to be addressed. It helps gauge the likelihood of success in addressing a problem, and how good a job society may do in reducing risk; it is not at all as useful in determining the severity of the problem that needs to be addressed.

The endangerment issue at its core is a decision on whether there is a risk to health and welfare that needs to be addressed, and the second approach would tend to indicate that the more likely a society is to solve a problem, the less likely there is a problem that needs to be addressed. This would mask the issue and provide a directionally wrong signal. Assume two different situations, both presenting the same serious risks to public health or welfare without consideration of adaptation or mitigation. The more successful society is projected to be in solving the serious problem in the future would mean the less likely we would be to make an endangerment finding at the inception identifying it as a problem that needs to be addressed. This is much less consistent with the logic embodied in CAA section 202(a), which separates the issue of whether there is a problem from the issue of what can be done to successfully address it.

In addition, the second approach would dramatically increase the complexity of the issues to resolve, and would do this by bringing in issues that are not the subject of the kind of scientific or technical judgments that Congress envisioned for the endangerment test. The legislative history indicates Congress was focused on issues of science and medicine, including issues at the frontiers of these fields. It referred to data, research resources, science and medicine, chemistry, biology, and statistics. There is no indication Congress envisioned exercising judgment on the very different types of issues involved in projecting the political actions likely to be taken by various local, State, and Federal governments, or judgments on the business or other decisions that are likely to be made by companies or other organizations, or the changes in personal behavior that may be occasioned by the adverse impacts of air pollution. The second approach would take EPA far away from the kind of judgments Congress envisioned for the endangerment test.

D. Geographic Scope of Impacts

It is the Administrator's view that the primary focus of the vulnerability, risk, and impact assessment is the United States. As described in Section IV of these Findings, the Administrator gives some consideration to climate change effects in world regions outside of the United States. Given the global nature of climate change, she has also examined potential impacts in other regions of the world. Greenhouse gases, once emitted, become well mixed in the atmosphere, meaning U.S. emissions can affect not only the U.S. population and environment, but other regions of the world as well. Likewise, emissions in other countries can affect the United States. Furthermore, impacts in other regions of the world may have consequences that in turn raise humanitarian, trade, and national security concerns for the United States.

Commenters argue that EPA does not have the authority to consider international effects. They contend that the burden is on EPA is to show endangerment based on impacts in the United States. They note that EPA proposed this approach, which is the only relevant issue for EPA. The purpose of CAA section 202(a), as the stated purpose of the CAA, commenters note, is to protect the quality of the nation's air resources and to protect the health and welfare of the U.S. population. Thus, they continue, international public health and welfare are not listed or stated, and are not encompassed by these provisions. Moreover, they argue that Congress addressed international impacts expressly in two other provisions of the CAA. They note that under CAA section 115, EPA considers emissions of pollutants that cause or contribute to air pollution that is reasonably anticipated to endanger public health or welfare in a foreign country, and that CAA section 179B addresses emissions of air pollutants in foreign countries that interfere with attainment of a National Ambient Air Quality Standards (NAAQS) in the United States. Because Congress intentionally addressed international impacts in those provision, commenters argue that the absence of this direction in CAA section 202(a) means that EPA is not to consider international effects when assessing endangerment under this provision.

Commenters fail to recognize that EPA's consideration of international effects is directed at evaluating their impact on the public health and welfare of the U.S. population. EPA is not considering international effects to determine whether the health and welfare of the public in a foreign country is endangered. Instead, EPA's consideration of international effects for purposes of determining endangerment is limited to how those international effects impact the health and welfare of the U.S. population.

The Administrator looked first at impacts in the United States itself, and determined that these impacts are reasonably anticipated to endanger the public health and the welfare of the U.S. population. That remains the Administrator's position, and by itself supports her determination of endangerment. The Administrator also considered the effects of global climate change outside the borders of the United States and evaluated them to determine whether these international effects impact the U.S. population, and if so whether it impacts the U.S. population in a manner that supports or does not support endangerment to the health and welfare of the U.S. public. She is not evaluating international effects to determine whether populations in a foreign country are endangered. The Administrator is looking at international effects solely for the purpose of evaluating their effects on the U.S. population.

For example, the U.S. population can be impacted by effects in other countries. These international effects can impact U.S. economic, trade, and humanitarian and national security interests. These would be potential effects on the U.S. population, brought about by the effects of climate change occurring outside the United States. It is fully reasonable and rational to expect that events occurring outside our borders can affect the U.S. population.

Thus, commenters misunderstand the role that international effects played in the proposal. The Administrator is not evaluating the impact of international effects on populations outside the United States; she is considering what impact these international effects could have on the U.S. population. That is fully consistent with the CAA's stated purpose of protecting the health and welfare of this nation's population.

E. Temporal Scope of Impacts

An additional parameter of the endangerment analysis is the timeframe. The Administrator's view is that the timeframe over which vulnerabilities, risks, and impacts are considered should be consistent with the timeframe over which greenhouse gases, once emitted, have an effect on climate. Thus the relevant time frame is decades to centuries for the primary greenhouse gases of concern. Therefore, in addition to reviewing recent observations, the underlying science upon which the Administrator is basing her findings generally considers the next several decades—the time period out to around 2100, and for certain impacts, the time period beyond 2100. How the accumulation of atmospheric greenhouse gases and resultant climate change may affect current and future generations is discussed in section IV in these Findings. By current generations we mean a near-term time frame of approximately the next 10 to 20 years; by future generations we mean a longer-term time frame extending beyond that. Some public comments were received that questioned making an endangerment finding based on current conditions, while others questioned EPA's ability to make an endangerment finding based on future projected conditions. Some of these comments are likewise addressed in Section IV in these Findings; and all comments on these temporal issues are addressed in the Response to Comments document.

F. Impacts of Potential Future Regulations and Processes That Generate Greenhouse Gas Emissions

This action is a stand-alone set of findings regarding endangerment and cause or contribute for greenhouse gases under CAA section 202(a), and does not contain any regulatory requirements. Therefore, this action does not attempt to assess the impacts of any future regulation. Although EPA would evaluate any future proposed regulation, many commenters argue that such a regulatory analysis should be part of the endangerment analysis.

Numerous commenters argue that EPA must fully consider the adverse and beneficial impacts of regulation together with the impacts of inaction, and describe this balancing as ''risk-risk analysis,'' ''health-health analysis,'' and most predominantly ''risk tradeoff analysis.'' Commenters argue that EPA's final endangerment finding would be arbitrary unless EPA undertakes this type of risk trade-off analysis.

Commenters specifically argue that EPA must consider the economic impact of regulation, including the Prevention of Significant Deterioration (PSD) permitting program for major stationary sources because it is triggered by a CAA section 202(a) standard, when assessing whether there is endangerment to public welfare. In other words, they argue that the Administrator should determine if finding endangerment and regulating greenhouse gases under the CAA would be worse for public health and welfare than not regulating. Commenters also argue that the reference to ''public'' health or welfare in CAA section 202, as well as the fact that impacts on the economy should be considered impacts to welfare, especially requires EPA to consider the full range of possible impacts of regulation. Commenters provide various predictions regarding how regulating greenhouse gases under the CAA more broadly will impact the public, industry, states the overall economy, and thus, they conclude, public health and welfare. Examples of commenters' predictions include potential adverse impacts on (1) the housing industry and the availability of affordable housing, (2) jobs and income due to industry moving overseas, (3) the agriculture industry and its ability to provide affordable food, and (4) the nation's energy supply. They also cite to the letter from the Office of Management and Budget provided with the ANPR, as well as interagency comments on the draft Proposed Findings, in support of their argument.

At least one commenter argues that EPA fails to discuss the public health or welfare benefits of the processes that *produce* the emissions. The commenter contends that for purposes of CAA section 202(a), this process would be the combustion of gasoline or other transportation fuel in new motor vehicles, and that for purposes of other CAA provisions with similar endangerment finding triggers, the processes would be the combustion of fossil fuel for electric generation and other activities. The commenter continues that EPA's decision to limit its analysis to the perceived detrimental aspects of emissions after they enter the atmosphere—as opposed to the possible positive aspects of emissions because of the processes that create the emissions—is based on EPA's overly narrow interpretation of both the meaning of the term ''emission'' in CAA section 202(a) (and therefore in other endangerment finding provisions) and the intent of these provisions. The commenter states that logically, it makes little sense to limit the definition of the term ''emission'' to only the ''air pollutants'' that are emitted. The commenter concludes that when EPA assesses whether the emission of greenhouse gases endanger public health and welfare, EPA must assess the dangers and benefits on both sides of the point where the emissions occur: in the atmosphere where the emissions lodge and, on the other side of the emitting stack or structure, in the processes that create the emissions. Otherwise, EPA will not be able to accurately assess whether the fact that society emits greenhouse gases is a benefit or a detriment. The commenter states that because greenhouse gas emissions, particularly carbon dioxide emissions, are so closely tied with all facets of modern life, a finding that greenhouse gas emissions endanger public health and welfare is akin to saying that modern life endangers public health or welfare. The commenter states that simply cannot be true because the lack of industrial activity that causes greenhouse gas emissions would pose other, almost certainly more serious health and welfare consequences.

Finally, some commenters argue that the impact of regulating under CAA section 202(a) supports making a final, negative endangerment finding. These commenters contend that the incredible costs associated with using the inflexible regulatory structure of the CAA will harm public health and welfare, and therefore EPA should exercise its discretion and find that greenhouse gases do not endanger public health and welfare because once EPA makes an endangerment finding under CAA section 202(a), it will be forced to regulate greenhouse gases under a number of other sections of the CAA, resulting in regulatory chaos.

At their core, these comments are not about whether commenters believe greenhouse gases may reasonably be anticipated to endanger public health or welfare, but rather about commenters' dissatisfaction with the decisions that Congress made regarding *the response* to any endangerment finding that EPA makes under CAA section 202(a). These comments do not discuss the science of greenhouse gases or climate change, or the impacts of climate change on public health or welfare. Instead they muddle the rather straightforward scientific judgment about whether there may be endangerment by throwing the potential impact of responding to the danger into the initial question. To use an analogy, the question of whether the cure is worse than the illness is different than the question of whether there is an illness in the first place. The question of whether there is endangerment is like the question of whether there is an illness. Once one knows there is an illness, then the next question is what to do, if anything, in response to that illness.

What these comments object to is that Congress has already made some decisions about next steps after a finding of endangerment, and commenters are displeased with the results. But if this is the case, commenters should take up their concerns with Congress, not EPA. EPA's charge is to issue new motor vehicle standards under CAA section 202(a) applicable to emissions of air pollutants that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare. It is not to find that there is no endangerment in order to avoid issuing those standards, and dealing with any additional regulatory impact.

Indeed, commenters' argument would insert policy considerations into the endangerment decision, an approach already rejected by the Supreme Court. First, as discussed in Section I.B of these Findings, in *Massachusetts* v. *EPA*, the court clearly indicated that the Administrator's decision must be a ''scientific judgment.'' 549 U.S. at 534. She must base her decision about endangerment on the science, and not on policy considerations about the repercussions or impact of such a finding.

Second, in considering whether the CAA allowed for economic considerations to play a role in the promulgation of the NAAQS, the

Supreme Court rejected arguments that because many more factors than air pollution might affect public health, EPA should consider compliance costs that produce health losses in setting the NAAQS. *Whitman* v. *ATA*, 531 U.S. at 457, 466 (2001). To be sure, the language in CAA section 109(b) applicable to the setting of a NAAQS is different than that in CAA section 202(a) regarding endangerment. But the concepts are similar—the NAAQS are about setting standards at a level requisite to protect public health (with an adequate margin of safety) and public welfare, and endangerment is about whether the current or projected future levels may reasonably be anticipated to endanger public health or welfare. In other words, both decisions essentially are based on assessing the harm associated with a certain level of air pollution.

Given this similarity in purpose, as well as the Court's instructions in *Massachusetts* v. *EPA* that the Administrator should base her decision on the science, EPA reasonably interprets the statutory endangerment language to be analogous to setting the NAAQS. Therefore, it is reasonable to interpret the endangerment test as not requiring the consideration of the impacts of implementing the statute in the event of an endangerment finding as part of the endangerment finding itself.[16]

Moreover, EPA does not believe that the impact of regulation under the CAA as a whole, let alone that which will result from this particular endangerment finding, will lead to the panoply of adverse consequences that commenters predict. EPA has the ability to fashion a reasonable and common-sense approach to address greenhouse gas emissions and climate change. The Administrator thinks that EPA has and will continue to take a measured approach to address greenhouse gas emissions. For example, the Agency's recent Mandatory Greenhouse Gas Reporting Rule focuses on only the largest sources of greenhouse gases in order to reduce the burden on smaller facilities.[17]

We also note that commenters' approach also is another version of the argument that EPA must consider adaptation and mitigation in the endangerment determination. Just as EPA should consider whether mitigation would *reduce* endangerment, commenters argue we should consider whether mitigation would *increase* endangerment. But as discussed previously, EPA disagrees and believes its approach better achieves the goals of the statute.

Finally, EPA simply disagrees with the commenter who argues that because we are better off now than before the industrial revolution, greenhouse gases cannot be found to endanger public health or welfare. As the DC Circuit noted in the *Ethyl* decision, ''[m]an's ability to alter his environment has developed far more rapidly than his ability to foresee with certainty the effects of his alterations.'' See *Ethyl Corp.,* 541 F.2d at 6. The fact that we as a society are better off now than 100 years ago, and that processes that produce greenhouse gases are a large part of this improvement, does not mean that those processes do not have unintended adverse impacts. It also was entirely reasonable for EPA to look at ''emissions'' as the pollution once it is emitted from the source into the air, and not also as the process that generates the pollution. Indeed, the definition of ''air pollutant'' talks in terms of substances ''emitted into or otherwise enter[ing] the ambient air'' (CAA section 302(g)). It is entirely appropriate for EPA to consider only the substance being emitted as the air pollution or air pollutant.

IV. The Administrator's Finding That Greenhouse Gases Endanger Public Health and Welfare

The Administrator finds that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and to endanger the public welfare of current and future generations. The Administrator is making this finding specifically with regard to six key directly-emitted, long-lived and well-mixed greenhouse gases: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The Administrator is making this judgment based on both current observations and projected risks and impacts into the future. Furthermore, the Administrator is basing this finding on impacts of climate change within the United States. However, the Administrator finds that when she considers the impacts on the U.S. population of risks and impacts occurring in other world regions, the case for endangerment to public health and welfare is only strengthened.

A. The Air Pollution Consists of Six Key Greenhouse Gases

The Administrator must define the scope and nature of the relevant air pollution for the endangerment finding under CAA section 202(a). In this final action, the Administrator finds that the air pollution is the combined mix of six key directly-emitted, long-lived and well-mixed greenhouse gases (henceforth ''well-mixed greenhouse gases''), which together, constitute the root cause of human-induced climate change and the resulting impacts on public health and welfare. These six greenhouse gases are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

EPA received public comments on this definition of air pollution from the Proposed Findings, and summarizes responses to some of those key comments below; fuller responses to public comments can be found in EPA's Response to Comments document, Volume 9. The Administrator acknowledges that other anthropogenic climate forcers also play a role in climate change. Many public comments either supported or opposed inclusion of other substances in addition to the six greenhouse gases for the definition of air pollution. EPA's responses to those comments are also summarized below, and in volume 9 of the Response to Comments document.

The Administrator explained her rationale for defining air pollution under CAA section 202(a) as the combined mix of the six greenhouse gases in the Proposed Findings. After review of the public comments, the Administrator is using the same definition of the air pollution in the

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[16] Indeed, some persons may argue that due to the similarities between setting a NAAQS and making an endangerment finding, EPA cannot consider the impacts of implementation of the statute.

[17] Note that it is EPA's current position that these Final Findings do not make well-mixed greenhouse gases ''subject to regulation'' for purposes of the CAA's Prevention of Significant Deterioration (PSD) and title V programs. *See, e.g.,* memorandum entitled ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (Dec. 18, 2008). While EPA is reconsidering this memorandum and is seeking public comment on the issues raised in it generally, including whether a final endangerment finding should trigger PSD, the effectiveness of the positions provided in the memorandum was not stayed pending that reconsideration. Prevention of Significant Deterioration (PSD): Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, 74 FR 515135, 51543–44 (Oct. 7, 2009). In addition, EPA has proposed new temporary thresholds for greenhouse gas emissions that define when PSD and title V permits are required for new or existing facilities. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (74 FR 55292, October 27, 2009). The proposed thresholds would ''tailor'' the permit programs to limit which facilities would be required to obtain PSD and title V permits. As noted in the preamble for the tailoring rule proposal, EPA also intends to evaluate ways to streamline the process for identifying GHG emissions control requirements and issuing permits. See the Response to Comments Document, Volume 11, and the Tailoring Rule, for more information.

final finding, for the following reasons: (1) These six greenhouse gas share common properties regarding their climate effects; (2) these six greenhouse gases have been estimated to be the primary cause of human-induced climate change, are the best understood drivers of climate change, and are expected to remain the key driver of future climate change; (3) these six greenhouse gases are the common focus of climate change science research and policy analyses and discussions; (4) using the combined mix of these gases as the definition (versus an individual gas-by-gas approach) is consistent with the science, because risks and impacts associated with greenhouse gas-induced climate change are not assessed on an individual gas approach; and (5) using the combined mix of these gases is consistent with past EPA practice, where separate substances from different sources, but with common properties, may be treated as a class (*e.g.,* oxides of nitrogen).

1. Common Physical Properties of the Six Greenhouse Gases

The common physical properties relevant to the climate change problem shared by the six greenhouse gases include the fact that they are long-lived in the atmosphere. ''Long-lived'' is used here to mean that the gas has a lifetime in the atmosphere sufficient to become globally well mixed throughout the entire atmosphere, which requires a minimum atmospheric lifetime of about one year.[18] Thus, this definition of air pollution is global in nature because the greenhouse gas emissions emitted from the United States (or from any other region of the world) become globally well mixed, such that it would not be meaningful to define the air pollution as the greenhouse gas concentrations over the United States as somehow being distinct from the greenhouse gas concentrations over other regions of the world.

It is also well established that each of these gases can exert a warming effect on the climate by trapping in heat that would otherwise escape to space. These six gases are directly emitted as greenhouse gases rather than forming as a greenhouse gas in the atmosphere after emission of a pre-cursor gas. Given these properties, the magnitude of the warming effect of each of these gases is generally better understood than other climate forcing agents that do not share these same properties (addressed in more detail below). The ozone-depleting substances that include chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HFCs) also share the same physical attributes discussed here, but for reasons discussed throughout the remainder of this section are not being included in the Administrator's definition of air pollution for this finding.

2. Evidence That the Six Greenhouse Gases Are the Primary Driver of Current and Projected Climate Change

a. Key Observations Driven Primarily by the Six Greenhouse Gases

The latest assessment of the USGCRP, as summarized in EPA's TSD, confirms the evidence presented in the Proposed Findings that current atmospheric greenhouse gas concentrations are now at elevated and essentially unprecedented levels as a result of both historic and current anthropogenic emissions. The global atmospheric carbon dioxide concentration has increased about 38 percent from pre-industrial levels to 2009, and almost all of the increase is due to anthropogenic emissions. The global atmospheric concentration of methane has increased by 149 percent since pre-industrial levels (through 2007); and the nitrous oxide concentration has increased 23 percent (through 2007). The observed concentration increase in these gases can also be attributed primarily to anthropogenic emissions. The industrial fluorinated gases have relatively low concentrations, but these concentrations have also been increasing and are almost entirely anthropogenic in origin.

Historic data show that current atmospheric concentrations of the two most important directly emitted, long-lived greenhouse gases (carbon dioxide and methane) are well above the natural range of atmospheric concentrations compared to at least the last 650,000 years. Atmospheric greenhouse gas concentrations have been increasing because anthropogenic emissions are outpacing the rate at which greenhouse gases are removed from the atmosphere by natural processes over timescales of decades to centuries. It also remains clear that these high atmospheric concentrations of greenhouse gases are the unambiguous result of human activities.

Together the six well-mixed greenhouse gases constitute the largest anthropogenic driver of climate change.[19] Of the total anthropogenic heating effect caused by the accumulation of the six well-mixed greenhouse gases plus other warming agents (that do not meet all of the Administrator's criteria that pertain to the six greenhouse gases) since pre-industrial times, the combined heating effect of the six well-mixed greenhouses is responsible for roughly 75 percent, and it is expected that this share may grow larger over time, as discussed below.

Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level. Global mean surface temperatures have risen by 0.74 °C (1.3 °F) (±0.18 °C) over the last 100 years. Eight of the 10 warmest years on record have occurred since 2001. Global mean surface temperature was higher during the last few decades of the 20th century than during any comparable period during the preceding four centuries.

The global surface temperature record relies on three major global temperature datasets, developed by NOAA, NASA, and the United Kingdom's Hadley Center. All three show an unambiguous warming trend over the last 100 years, with the greatest warming occurring over the past 30 years.[20] Furthermore, all three datasets show that eight of the 10 warmest years on record have occurred since 2001; that the 10 warmest years have all occurred in the past 12 years; and that the 20 warmest years have all occurred since 1981. Though most of the warmest years on record have occurred in the last decade in all available datasets, the rate of warming has, for a short time in the

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[18] The IPCC also refers to these six GHGs as long-lived. Methane has an atmospheric lifetime of roughly a decade. One of the most commonly used hydrofluorocarbons (HFC–134a) has a lifetime of 14 years. Nitrous oxide has a lifetime of 114 years; sulfur hexafluoride over 3,000 years; and some PFCs up to 10,000 to 50,000 years. Carbon dioxide in the atmosphere is sometimes approximated as having a lifetime of roughly 100 years, but for a given amount of carbon dioxide emitted a better description is that some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

[19] As summarized in EPA's TSD, the global average net effect of the increase in atmospheric greenhouse gas concentrations, plus other human activities (*e.g.,* land use change and aerosol emissions), on the global energy balance since 1750 has been one of warming. This total net heating effect, referred to as forcing, is estimated to be +1.6 (+0.6 to +2.4) Watts per square meter (W/m^2), with much of the range surrounding this estimate due to uncertainties about the cooling and warming effects of aerosols. The combined radiative forcing due to the cumulative (*i.e.,* 1750 to 2005) increase in atmospheric concentrations of CO_2, CH_4, and N_2O is estimated to be +2.30 (+2.07 to +2.53) W/m^2. The rate of increase in positive radiative forcing due to these three GHGs during the industrial era is very likely to have been unprecedented in more than 10,000 years.

[20] *See* section 4 of the TSD for more detailed information about the three global temperature datasets.

Hadley Center record, slowed. However, the NOAA and NASA trends do not show the same marked slowdown for the 1999–2008 period. Year-to-year fluctuations in natural weather and climate patterns can produce a period that does not follow the long-term trend. Thus, each year may not necessarily be warmer than every year before it, though the long-term warming trend continues.[21]

The scientific evidence is compelling that elevated concentrations of heat-trapping greenhouse gases are the root cause of recently observed climate change. The IPCC conclusion from 2007 has been re-confirmed by the June 2009 USGCRP assessment that most of the observed increase in global average temperatures since the mid-20th century is very likely [22] due to the observed increase in anthropogenic greenhouse gas concentrations. Climate model simulations suggest natural forcing alone (*e.g.,* changes in solar irradiance) cannot explain the observed warming.

The attribution of observed climate change to anthropogenic activities is based on multiple lines of evidence. The first line of evidence arises from our basic physical understanding of the effects of changing concentrations of greenhouse gases, natural factors, and other human impacts on the climate system. The second line of evidence arises from indirect, historical estimates of past climate changes that suggest that the changes in global surface temperature over the last several decades are unusual.[23] The third line of evidence arises from the use of computer-based climate models to simulate the likely patterns of response of the climate system to different forcing mechanisms (both natural and anthropogenic).

The claim that natural internal variability or known natural external forcings can explain most (more than half) of the observed global warming of the past 50 years is inconsistent with the vast majority of the scientific literature, which has been synthesized in several assessment reports. Based on analyses of widespread temperature increases throughout the climate system and changes in other climate variables, the IPCC has reached the following conclusions about external climate forcing: ‘‘It is extremely unlikely (<5 percent) that the global pattern of warming during the past half century can be explained without external forcing, and very unlikely that it is due to known natural external causes alone’’ (Hegerl *et al.,* 2007). With respect to internal variability, the IPCC reports the following: ‘‘The simultaneous increase in energy content of all the major components of the climate system as well as the magnitude and pattern of warming within and across the different components supports the conclusion that the cause of the [20th century] warming is extremely unlikely (<5 percent) to be the result of internal processes’’ (Hegerl *et al.,* 2007). As noted in the TSD, the observed warming can only be reproduced with models that contain both natural and anthropogenic forcings, and the warming of the past half century has taken place at a time when known natural forcing factors alone (solar activity and volcanoes) would likely have produced cooling, not warming.

United States temperatures also warmed during the 20th and into the 21st century; temperatures are now approximately 0.7 °C (1.3 °F) warmer than at the start of the 20th century, with an increased rate of warming over the past 30 years. Both the IPCC and CCSP reports attributed recent North American warming to elevated greenhouse gas concentrations. The CCSP (2008g) report finds that for North America, ‘‘more than half of this warming [for the period 1951–2006] is likely the result of human-caused greenhouse gas forcing of climate change.’’

Observations show that changes are occurring in the amount, intensity, frequency, and type of precipitation. Over the contiguous United States, total annual precipitation increased by 6.1 percent from 1901–2008. It is likely that there have been increases in the number of heavy precipitation events within many land regions, even in those where there has been a reduction in total precipitation amount, consistent with a warming climate.

There is strong evidence that global sea level gradually rose in the 20th century and is currently rising at an increased rate. It is very likely that the response to anthropogenic forcing contributed to sea level rise during the latter half of the 20th century. It is not clear whether the increasing rate of sea level rise is a reflection of short-term variability or an increase in the longer-term trend. Nearly all of the Atlantic Ocean shows sea level rise during the last 50 years with the rate of rise reaching a maximum (over 2 mm per year) in a band along the U.S. east coast running east-northeast.

Satellite data since 1979 show that annual average Arctic sea ice extent has shrunk by 4.1 percent per decade. The size and speed of recent Arctic summer sea ice loss is highly anomalous relative to the previous few thousands of years.

Widespread changes in extreme temperatures have been observed in the last 50 years across all world regions including the United States. Cold days, cold nights, and frost have become less frequent, while hot days, hot nights, and heat waves have become more frequent.

Observational evidence from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases. However, directly attributing specific regional changes in climate to emissions of greenhouse gases from human activities is difficult, especially for precipitation.

Ocean carbon dioxide uptake has lowered the average ocean pH (increased the acidity) level by approximately 0.1 since 1750. Consequences for marine ecosystems may include reduced calcification by shell-forming organisms, and in the longer term, the dissolution of carbonate sediments.

Observations show that climate change is currently affecting U.S. physical and biological systems in significant ways. The consistency of these observed changes in physical and biological systems and the observed significant warming likely cannot be explained entirely due to natural variability or other confounding non-climate factors.

b. Key Projections Based Primarily on Future Scenarios of the Six Greenhouse Gases

There continues to be no reason to expect that, without substantial and near-term efforts to significantly reduce emissions, atmospheric levels of greenhouse gases will not continue to climb, and thus lead to ever greater rates of climate change. Given the long atmospheric lifetime of the six greenhouse gases, which range from roughly a decade to centuries, future atmospheric greenhouse gas

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[21] Karl T. *et al.,* (2009).

[22] The IPCC Fourth Assessment Report uses specific terminology to convey likelihood and confidence. Likelihood refers to a probability that the statement is correct or that something will occur. ‘‘Virtually certain’’ conveys greater than 99 percent probability of occurrence; ‘‘very likely’’ 90 to 99 percent; ‘‘likely’’ 66 to 90 percent. IPCC assigns confidence levels as to the correctness of a statement. ‘‘Very high confidence’’ conveys at least 9 out of 10 chance of being correct; ‘‘high confidence’’ about 8 out of 10 chance; ‘‘medium confidence’’ about 5 out of 10 chance. The USGCRP uses the same or similar terminology in its reports. See also Box 1.2 of the TSD. Throughout this document, this terminology is used in conjunction with statements from the IPCC and USGCRP reports to convey the same meaning that those reports intended. In instances where a word such as ‘‘likely’’ may appear outside the context of a specific IPCC or USGCRP statement, it is not meant to necessarily convey the same quantitative meaning as the IPCC terminology.

[23] Karl T. *et al.* (2009).

concentrations for the remainder of this century and beyond will be influenced not only by future emissions but indeed by present-day and near-term emissions. Consideration of future plausible scenarios, and how our current greenhouse gas emissions essentially commit present and future generations to cope with an altered atmosphere and climate, reinforces the Administrator's judgment that it is appropriate to define the combination of the six key greenhouse gases as the air pollution.

Most future scenarios that assume no explicit greenhouse gas mitigation actions (beyond those already enacted) project increasing global greenhouse gas emissions over the century, which in turn result in climbing greenhouse gas concentrations. Under the range of future emission scenarios evaluated by the assessment literature, carbon dioxide is expected to remain the dominant anthropogenic greenhouse gas, and thus driver of climate change, over the course of the 21st century. In fact, carbon dioxide is projected to be the largest contributor to total radiative forcing in all periods and the radiative forcing associated with carbon dioxide is projected to be the fastest growing. For the year 2030, projections of the six greenhouse gases show an increase of 25 to 90 percent compared with 2000 emissions. Concentrations of carbon dioxide and the other well-mixed gases increase even for those scenarios where annual emissions toward the end of the century are assumed to be lower than current annual emissions. The radiative forcing associated with the non-carbon dioxide well-mixed greenhouse gases is still important and increasing over time. Emissions of the ozone-depleting substances are projected to continue decreasing due to the phase-out schedule under the Montreal Protocol on Substances that Deplete the Ozone Layer. Considerable uncertainties surround the estimates and future projections of anthropogenic aerosols; future atmospheric concentrations of aerosols, and thus their respective heating or cooling effects, will depend much more on assumptions about future emissions because of their short atmospheric lifetimes compared to the six well-mixed greenhouse gases.

Future warming over the course of the 21st century, even under scenarios of low emissions growth, is very likely to be greater than observed warming over the past century. According to climate model simulations summarized by the IPCC, through about 2030, the global warming rate is affected little by the choice of different future emission scenarios. By the end of the century, projected average global warming (compared to average temperature around 1990) varies significantly depending on emissions scenario and climate sensitivity assumptions, ranging from 1.8 to 4.0 °C (3.2 to 7.2 °F), with an uncertainty range of 1.1 to 6.4 °C (2.0 to 11.5 °F).

All of the United States is very likely to warm during this century, and most areas of the United States are expected to warm by more than the global average. The largest warming is projected to occur in winter over northern parts of Alaska. In western, central and eastern regions of North America, the projected warming has less seasonal variation and is not as large, especially near the coast, consistent with less warming over the oceans.

3. The Six Greenhouse Gases Are Currently the Common Focus of the Climate Change Science and Policy Communities

The well-mixed greenhouse gases are currently the common focus of climate science and policy analyses and discussions. For example, the United Nations Framework Convention on Climate Change (UNFCCC), signed and ratified by the United States in 1992, requires its signatories to ''develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies * * *'' [24] [25] To date, the focus of UNFCCC actions and discussions has been on the six greenhouse gases that are the same focus of these Findings.

Because of these common properties, it has also become common practice to compare these gases on a carbon dioxide equivalent basis, based on each gas's warming effect relative to carbon dioxide (the designated reference gas) over a specified timeframe. For example, both the annual *Inventory of U.S. Greenhouse Gases and Sinks* published by EPA and the recently finalized EPA Mandatory Greenhouse Gas Reporting Rule (74 FR 56260), use the carbon dioxide equivalent metric to sum and compare these gases, and thus accept the common climate-relevant properties of these gases for their treatment as a group. This is also common practice internationally as the UNFCCC reporting guidelines for developed countries, and the Clean Development Mechanism procedures for developing countries both require the use of global warming potentials published by the IPCC to convert the six greenhouse gases into their respective carbon dioxide equivalent units.

4. Defining Air Pollution as the Aggregate Group of Six Greenhouse Gases Is Consistent With Evaluation of Risks and Impacts Due to Human-Induced Climate Change

Because the well-mixed greenhouse gases are collectively the primary driver of current and projected human-induced climate change, all current and future risks due to human-induced climate change—whether these risks are associated with increases in temperature, changes in precipitation, a rise in sea levels, changes in the frequency and intensity of weather events, or more directly with the elevated greenhouse gas concentrations themselves—can be associated with this definition of air pollution.

5. Defining the Air Pollution as the Aggregate Group of Six Greenhouse Gases Is Consistent With Past EPA Practice

Treating the air pollution as the aggregate of the well-mixed greenhouse gases is consistent with other provisions of the CAA and previous EPA practice under the CAA, where separate emissions from different sources but with common properties may be treated as a class (*e.g.,* particulate matter (PM)). This approach addresses the total, cumulative effect that the elevated concentrations of the six well-mixed greenhouse gases have on climate, and thus on different elements of health, society and the environment.[24]

EPA treats, for example, PM as a common class of air pollution; PM is a complex mixture of extremely small particles and liquid droplets. Particle pollution is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

6. Other Climate Forcers Not Being Included in the Definition of Air Pollution for This Finding

Though the well-mixed greenhouse gases that make up the definition of air pollution for purposes of making the endangerment decision under CAA section 202(a) constitute the primary

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[24] Due to the cumulative purpose of the statutory language, even if the Administrator were to look at the atmospheric concentration of each greenhouse gas individually, she would still consider the impact of the concentration of a single greenhouse gas in combination with that caused by the other greenhouse gases.

[25] The range of uncertainty in the current magnitude of black carbon's climate forcing effect is evidenced by the ranges presented by the IPCC Fourth Assessment Report (2007) and the more recent study by Ramanathan, V. and Carmichael, G. (2008) Global and regional climate changes due to black carbon. Nature Geoscience, 1(4): 221–227.

driver of human-induced climate change, there are other substances emitted from human activities that contribute to climate change and deserve careful attention, but are not being included in the air pollution definition for this particular action. These substances are discussed immediately below.

a. Black Carbon

Several commenters request that black carbon be included in the definition of air pollution because of its warming effect on the climate. Black carbon is not a greenhouse gas, rather, it is an aerosol particle that results from the incomplete combustion of carbon contained in fossil fuels and biomass, and remains in the atmosphere for only about a week. Unlike any of the greenhouse gases being addressed by this action, black carbon is a component of particulate matter (PM), where PM is a criteria air pollutant under section 108 of the CAA. The extent to which black carbon makes up total PM varies by emission source, where, for example, diesel vehicle PM emissions contain a higher fraction of black carbon compared to most other PM emission sources. Black carbon causes a warming effect primarily by absorbing incoming and reflected sunlight (whereas greenhouse gases cause warming by trapping outgoing, infrared heat), and by darkening bright surfaces such as snow and ice, which reduces reflectivity. This latter effect, in particular, has been raising concerns about the role black carbon may be playing in observed warming and ice melt in the Arctic.

As stated in the April 2009 Proposed Findings, there remain some significant scientific uncertainties about black carbon's total climate effect,[25] as well as concerns about how to treat the short-lived black carbon emissions alongside the long-lived, well-mixed greenhouse gases in a common framework (*e.g.,* what are the appropriate metrics to compare the warming and/or climate effects of the different substances, given that, unlike greenhouse gases, the magnitude of aerosol effects can vary immensely with location and season of emissions). Nevertheless, the Administrator recognizes that black carbon is an important climate forcing agent and takes very seriously the emerging science on black carbon's contribution to global climate change in general and the high rates of observed climate change in the Arctic in particular. As noted in the Proposed Findings, EPA has various pending petitions under the CAA calling on the Agency to make an endangerment finding and regulate black carbon emissions.

b. Other Climate Forcers

There are other climate forcers that play a role in human-induced climate change that were mentioned in the Proposed Findings, and were the subject of some public comments. These include the stratospheric ozone-depleting substances, nitrogen trifluoride (NF_3), water vapor, and tropospheric ozone.

As mentioned above, the ozone-depleting substances (CFCs and HCFCs) do share the same physical, climate-relevant attributes as the six well-mixed greenhouse gases; however, emissions of these substances are playing a diminishing role in human-induced climate change. They are being controlled and phased out under the Montreal Protocol on Substances that Deplete the Ozone Layer. Because of this, the major scientific assessment reports such as those from IPCC focus primarily on the same six well-mixed greenhouse gases included in the definition of air pollution in these Findings. It is also worth noting that the UNFCCC, to which the United States is a signatory, addresses ''all greenhouse gases not controlled by the Montreal Protocol.'' [26] One commenter noted that because the Montreal Protocol controls production and consumption of ozone-depleting substances, but not existing banks of the substances, that CFCs should be included in the definition of air pollution in this finding, which might, in turn, create some future action under the CAA to address the banks of ozone-depleting substances as a climate issue. However, the primary criteria for defining the air pollution in this finding is the focus on the core of the climate change problem, and concerns over future actions to control depletion of stratospheric ozone are separate from and not central to the air pollution causing climate change.

Nitrogen trifluoride also shares the same climate-relevant attributes as the six well-mixed greenhouse gases, and it is also included in EPA's Mandatory Greenhouse Gas Reporting Rule (FR 74 56260). However, the Administrator is maintaining the reasoning laid out in the Proposed Findings to not include NF_3 in the definition of air pollution for this finding because the overall magnitude of its forcing effect on climate is not yet well quantified. EPA will continue to track the science on NF_3.

A number of public comments question the exclusion of water vapor from the definition of air pollution because it is the most important greenhouse gas responsible for the natural, background greenhouse effect. The Administrator's reasoning for excluding water vapor, was described in the Proposed Findings and is summarized here with additional information in Volume 10 of the Response to Comments document. First, climate change is being driven by the buildup in the atmosphere of greenhouse gases. The direct emissions primarily responsible for this are the six well-mixed greenhouse gases. Direct anthropogenic emissions of water vapor, in general, have a negligible effect and are thus not considered a primary driver of human-induced climate change. EPA plans to further evaluate the issues of emissions of water that are implicated in the formation of contrails and also changes in water vapor due to local irrigation. At this time, however, the findings of the IPCC state that the total forcing from these sources is small and that the level of understanding is low.

Water produced as a byproduct of combustion at low altitudes has a negligible contribution to climate change. The residence time of water vapor is very short (days) and the water content of the air in the long term is a function of temperature and partial pressure, with emissions playing no role. Additionally, the radiative forcing of a given mass of water at low altitudes is much less than the same mass of carbon dioxide. Water produced at higher altitudes could potentially have a larger impact. The IPCC estimated the contribution of changes in stratospheric water vapor due to methane and other sources, as well as high altitude contributions from contrails, but concluded that both contributions were small, with a low level of understanding. The report also addressed anthropogenic contributions to water vapor arising from large scale irrigation, but assigned it a very low level of understanding, and suggested that the cooling from evaporation might outweigh the warming from its small radiative contribution.

Increases in tropospheric ozone concentrations have exerted a significant anthropogenic warming effect since pre-industrial times. However, as explained in the Proposed Findings, tropospheric ozone is not a long-lived, well-mixed greenhouse gas, and it is not directly emitted. Rather it forms in the atmosphere from emissions of pre-cursor gases. There is increasing attention in climate change research and the policy community about the extent to which further reductions in tropospheric ozone levels may help

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[26] UNFCCC, Art. 4.1(b).

slow down climate change in the near term. The Administrator views this issue seriously but maintains that tropospheric ozone is sufficiently different such that it deserves an evaluation and treatment separate from this finding.

7. Summary of Key Comments on Definition of Air Pollution

a. It Is Reasonable for the Administrator To Define the Air Pollution as Global Concentrations of the Well-Mixed Greenhouse Gases

Many commenters argue that EPA does not have the authority to establish domestic rights and obligations based on environmental conditions that are largely attributed to foreign nations and entities that are outside the jurisdiction of EPA under the CAA. They contend that in this case, the bulk of emissions that would lead to mandatory emissions controls under the CAA would not and could not be regulated under the CAA. They state that CAA requirements cannot be enforced against foreign sources of air pollution, and likewise domestic obligations under the CAA cannot be caused by foreign emissions that are outside the United States. The commenters argue that EPA committed procedural error by not addressing this legal issue of authority in the proposal.

Commenters cite no statutory text or judicial authority for this argument, and instead rely entirely on an analogy to the issues concerning the exercise of extra-territorial jurisdiction. The text of CAA section 202(a), however, does not support this claim. Nothing in CAA section 202(a) limits the term air pollution to those air pollution matters that are caused solely or in large part by domestic emissions. The only issue under CAA section 202(a) is whether the air pollution is reasonably anticipated to endanger, and whether emissions from one domestic source category—new motor vehicles—cause or contribute to this air pollution. Commenters would read into this an additional cause or contribute test—whether foreign sources cause or contribute to the air pollution in such a way that the air pollution is largely attributable to the foreign emissions, or the bulk of emissions causing the air pollution are from foreign sources. There is no such provision in CAA section 202(a). Congress was explicit about the contribution test it imposed, and the only source that is relevant for purposes of contribution is new motor vehicles. Commenters suggest an ill-defined criterion that is not in the statute.

In addition, as discussed in Section II of these Findings, Congress intentionally meant the agency to judge the air pollution endangerment criteria based on the ''cumulative impact of all sources of a pollutant,'' and not an incremental look at just the endangerment from a subset of sources. Commenters' arguments appear to lead to this result. Under the commenters' approach, in those cases where the bulk of emissions which form the air pollution come from foreign sources, EPA apparently would have no authority to make an endangerment finding. Logically, EPA would be left with the option of identifying and evaluating the air pollution attributable to domestic sources alone, and determining whether that narrowly defined form of air pollution endangers public health or welfare. This is the kind of unworkable, incremental approach that was rejected by the court in *Ethyl* and by Congress in the 1977 amendments adopting this provision.

The analogy to extra-territorial jurisdiction is also not appropriate. The endangerment finding itself does not exercise jurisdiction over any source, domestic or foreign. It is a judgment that is a precondition for exercising regulatory authority. Under CAA section 202(a), any exercise of regulatory authority following from this endangerment finding would be for new motor vehicles either manufactured in the United States or imported into the United States. There would be no extra-territorial exercise of jurisdiction. The core issues for endangerment focus on impacts inside the United States, not outside the United States. In addition, the contribution finding is based solely on the contribution from new motor vehicles built in or imported to the United States. The core judgments that need to be made under CAA section 202(a) are all focused on actions and impacts inside the United States. This does not raise any concerns about an extra-territorial exercise of jurisdiction. The basis for the endangerment and contribution findings is fully consistent with the principles underlying the desire to avoid exercises of extra-territorial jurisdiction. Any limitations on the ability to exercise control over foreign sources of emissions does not, however, call into question the authority under CAA section 202 to exercise control over domestic sources of emissions based on their contribution to an air pollution problem that is judged to endanger public health or welfare based on impacts occurring in the United States or otherwise affecting the United States and its citizens.

In essence, commenters are concerned about the effectiveness of the domestic control strategies that can be adopted to address a global air pollution problem that is caused only in part by domestic sources of emissions. While that is a quite valid and important policy concern, it does not translate into a legal limitation on EPA's authority to make an endangerment finding. Neither the text nor the legislative history of CAA section 202(a) support such an interpretation and Congress explicitly separated the decision on endangerment from the decision on what controls are required or appropriate once an affirmative endangerment finding has been made. The effectiveness of the resulting regulatory controls is not a relevant factor to determining endangerment.

EPA also committed no procedural flaw as argued by commenters. The proposal fully explored the interpretation of endangerment and cause or contribution under CAA section 202(a), and was very clear that EPA was considering air pollution to mean the elevated global concentration of greenhouse gases in the atmosphere, recognizing that these atmospheric concentrations were the result of world wide emissions, not just or even largely U.S. emissions. The separation of the effectiveness of the control strategy from the endangerment criteria, and the need to consider the cumulative impact of all sources in evaluating endangerment was clearly discussed. Commenters received fair notice of EPA's proposal and the basis for it.

Similarly, some commenters argue that EPA's proposal defines air pollution as global air pollution, but EPA is limited to evaluating domestic air only; in other words that EPA may only regulate domestic emissions with localized effects. They argue this limitation derives from the purpose of the CAA—to enhance the quality of the Nation's air resources, recognizing that air pollution prevention and control focus on the sources of the emissions, and are the primary responsibility of States and local governments. Therefore, commenters continue, that ''air pollution'' has to be air pollution that originates domestically and is to be addressed only at the domestic source. Sections 115 and 179B of the CAA, as discussed below, reflect this intention as well. The result, they conclude, is that ''air pollution'' as used in CAA section 202(a), includes only pollution that originates domestically, where the effects occur locally. They argue EPA has improperly circumvented this by a ''local-global-local'' analysis that injects global air pollution into the middle of the endangerment test.

The statutory arguments made by the commenters attempt to read an unrealistic limitation into the general provisions discussed. The issues are similar in nature to those raised by the commenters arguing that EPA has no authority to establish domestic rights and obligations based on environmental conditions that are largely attributable to emissions from foreign nations and entities that are outside the jurisdiction of EPA under the CAA. In both cases, the question is whether EPA has authority to make an endangerment finding when the air pollution of concern is a relatively homogenous atmospheric concentration of greenhouse gases. According to the commenters, although this global pool includes the air over the United States, and leads to impacts in the United States and on the U.S. population, Congress prohibited EPA from addressing this air pollution problem because of its global aspects.

The text of the CAA does not specifically address this, as the term air pollution is not defined. EPA interprets this term as including the air pollution problem involved in this case—elevated atmospheric concentration of greenhouse gases that occur in the air above the United States as well as across the globe, and where this pool of global gases leads to impacts in the United States and on the U.S. population. This is fully consistent with the statutory provisions discussed by commenters. This approach seeks to protect the Nation's air resources, as clearly the Nation's air resources are an integral part of this global pool. The Nation's air resources by definition are not an isolated atmosphere that only contains molecules emitted within the United States, or an atmosphere that bears no relationship to the rest of the globe's atmosphere. There is no such real world body of air. Protecting the Nation's resources of clean air means to protect the air in the real world, not an artificial construct of ''air'' that ignores the many situations where the air over our borders includes compounds and pollutants emitted outside our borders, and in this case to ignore the fact that the air over our borders will by definition have elevated concentrations of greenhouse gases only when the air around the globe also has such concentrations. The suggested narrow view of ''air pollution'' does not further the protection of the Nation's air resources, but instead attempts to limit such protection by defining these resources in a scientifically artificial way that does not comport with how the air in the atmosphere is formed or changes over time, how it relates to and interacts with air around the globe, and how the result of this can affect the U.S. population.

The approach suggested by commenters fails to provide an actual definition for EPA to follow—for example, would U.S. or domestic ''air pollution'' be limited to only those air concentrations composed of molecules that originated in the United States? Is there a degree of external gases or compounds that could be allowed? Would it ignore the interaction and relationship between the air over the U.S. borders and the air around the rest of the globe? The latter approach appears to be the one suggested by commenters. Commenters' approach presumably would call for EPA to only consider the effects that derive solely from the air over our borders, and to ignore any effects that occur within the United States that are caused by air around the globe. However the air over the United States will by definition affect climate change only in circumstances where the air around the world is also doing so. The impacts of the air over the United States cannot be assessed separately from the impacts from the global pool, as they occur together and work together to affect the climate. Ignoring the real world nature of the Nation's air resources, in the manner presumably suggested by the commenters, would involve the kind of unworkable, incremental, and artificially isolating approach that was rejected by the court in *Ethyl* and by Congress in 1977. Congress intended EPA to interpret this provision by looking at air pollutants and air pollution problems in a broad manner, not narrowly, to evaluate problems within their broader context and not to attempt to isolate matters in an artificial way that fails to account for the real world context that lead to health and welfare impacts on the public. Commenters' suggested interpretation fails to implement this intention of Congress.

Commenters in various places refer to the control of the pollution, and the need for it to be aimed at local sources. That is addressed in the standard setting portion of CAA section 202(a), as in other similar provisions. The endangerment provision does not address how the air pollution problem should be addressed—who should be regulated and how they should be regulated. The endangerment provision addresses a different issue—is there an air pollution problem that should be addressed? In that context, EPA rejects the artificially narrow interpretation suggested by the commenters, and believes its broader interpretation in this case is reasonable and consistent with the intention of Congress.

b. Consideration of Greenhouse Gases as Air Pollution Given Their Impact Is Through Climate Rather Than Direct Toxic Effects

A number of commenters argue that carbon dioxide and the other greenhouse gases should not be defined as the air pollution because these gases do not cause direct human health effects, such as through inhalation. Responses to such comments are summarized in Section IV.B.1 of these Findings in the discussion of the public health and welfare nature of the endangerment finding.

c. The Administrator's Reliance on the Global Temperature Data Is a Reasonable Indicator of Human-Induced Climate Change

We received many comments suggesting global temperatures have stopped warming. The commenters base this conclusion on temperature trends over only the last decade. While there have not been strong trends over the last seven to ten years in global surface temperature or lower troposphere temperatures measured by satellites, this pause in warming should not be interpreted as a sign that the Earth is cooling or that the science supporting continued warming is in error. Year-to-year variability in natural weather and climate patterns make it impossible to draw any conclusions about whether the climate system is warming or cooling from such a limited analysis. Historical data indicate short-term trends in long-term time series occasionally run counter to the overall trend. All three major global surface temperature records show a continuation of long-term warming. Over the last century, the global average temperature has warmed at the rate of about 0.13 °F (0.072 °C) per decade in all three records. Over the last 30 years, the global average surface temperature has warmed by about 0.30 °F (0.17 °C) per decade. Eight of the 10 warmest years on record have occurred since 2001 and the 20 warmest years have all occurred since 1981. Satellite measurements of the troposphere also indicate warming over the last 30 years at a rate of 0.20 to 0.27 °F (0.11 °C to 0.15 °C) per decade. Please see the relevant volume of the Response to Comments document for more detailed responses.

Some commenters indicate the global surface temperature records are biased by urbanization, poor siting of instruments, observation methods, and other factors. Our review of the literature suggests that these biases have in many cases been corrected for, are largely random where they remain, and therefore cancel out over large regions. Furthermore, we note that though the three global surface temperature records use differing techniques to analyze much of the same data, they produce almost the same results, increasing our confidence in their legitimacy. The assessment literature has concluded that warming of the climate system is unequivocal. The warming trend that is evident in all of the temperature records is confirmed by other independent observations, such as the melting of Arctic sea ice, the retreat of mountain glaciers on every continent, reductions in the extent of snow cover, earlier blooming of plants in the spring, and increased melting of the Greenland and Antarctic ice sheets. Please see the relevant volume of the Response to Comments document for more detailed responses.

A number of commenters argue that the warmth of the late 20th century is not unusual relative to the past 1,000 years. They maintain temperatures were comparably warm during the Medieval Warm Period (MWP) centered around 1000 A.D. We agree there was a Medieval Warm Period in many regions but find the evidence is insufficient to assess whether it was globally coherent. Our review of the available evidence suggests that Northern Hemisphere temperatures in the MWP were probably between 0.1 °C and 0.2 °C below the 1961–1990 mean and significantly below the level shown by instrumental data after 1980. However, we note significant uncertainty in the temperature record prior to 1600 A.D. Please see the relevant volume of the Response to Comments document for more detailed responses.

d. Ability To Attribute Observed Climate Change to Anthropogenic, Well-Mixed Greenhouse Gases

Many commenters question the link between observed temperatures and anthropogenic greenhouse gas emissions. They suggest internal variability of the climate system and natural forcings explain observed temperature trends and that anthropogenic greenhouse gases play, at most, a minor role. However, the attribution of most of the recent warming to anthropogenic activities is based on multiple lines of evidence. The first line of evidence arises from our basic physical understanding of the effects of changing concentrations of greenhouse gases, natural factors, and other human impacts on the climate system. Greenhouse gas concentrations have indisputably increased and their radiative properties are well established. The second line of evidence arises from indirect, historical estimates of past climate changes that suggest that the changes in global surface temperature over the last several decades are unusual. The third line of evidence arises from the use of computer-based climate models to simulate the likely patterns of response of the climate system to different forcing mechanisms (both natural and anthropogenic). These models are unable to replicate the observed warming unless anthropogenic emissions of greenhouse gases are included in the simulations. Natural forcing alone cannot explain the observed warming. In fact, the assessment literature[27] indicates the sum of solar and volcanic forcing in the past half century would likely have produced cooling, not warming. Please see the relevant volume of the Response to Comments for more detailed responses.

B. The Air Pollution Is Reasonably Anticipated To Endanger Both Public Health and Welfare

The Administrator finds that the elevated atmospheric concentrations of the well-mixed greenhouse gases may reasonably be anticipated to endanger the public health and welfare of current and future generations. This section describes the major pieces of scientific evidence supporting the Administrator's endangerment finding, discusses both the public health and welfare nature of the endangerment finding, and addresses a number of key issues the Administrator considered when evaluating the state of the science as well as key public comments on the Proposed Findings. Additional detail can be found in the TSD and the Response to Comments document.

As described in Section II of these Findings, the endangerment test under CAA section 202(a) does not require the Administrator to identify a bright line, quantitative threshold above which a positive endangerment finding can be made. The statutory language explicitly calls upon the Administrator to use her judgment. This section describes the general approach used by the Administrator in reaching the judgment that a positive endangerment finding should be made, as well as the specific rationale for finding that the greenhouse gas air pollution may reasonably be anticipated to endanger both public health and welfare.

First, the Administrator finds the scientific evidence linking human emissions and resulting elevated atmospheric concentrations of the six well-mixed greenhouse gases to observed global and regional temperature increases and other climate changes to be sufficiently robust and compelling. This evidence is briefly explained in more detail in Section V of these Findings. The Administrator recognizes that the climate change associated with elevated atmospheric concentrations of carbon dioxide and the other well-mixed greenhouse gases have the potential to affect essentially every aspect of human health, society and the natural environment. The Administrator is therefore not limiting her consideration of potential risks and impacts associated with human emissions of greenhouse gases to any one particular element of human health, sector of the economy, region of the country, or to any one particular aspect of the natural environment. Rather, the Administrator is basing her finding on the total weight of scientific evidence, and what the science has to say regarding the nature and potential magnitude of the risks and impacts across all climate-sensitive elements of public health and welfare, now and projected out into the foreseeable future.

The Administrator has considered the state of the science on how human emissions and the resulting elevated atmospheric concentrations of well-mixed greenhouse gases may affect each of the major risk categories, *i.e.,* those that are described in the TSD, which include human health, air quality, food production and agriculture, forestry, water resources, sea level rise and coastal areas, the energy sector, infrastructure and settlements, and ecosystems and wildlife. The Administrator understands that the nature and potential severity of impacts can vary across these different elements of public health and welfare, and that they can vary by region, as well as over time.

The Administrator is therefore aware that, because human-induced climate change has the potential to be far-reaching and multi-dimensional, not all

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[27] Solomon, S., D. Qin, M. Manning, R.B. Alley, T. Berntsen, N.L. Bindoff, Z. Chen, A. Chidthaisong, J.M. Gregory, G.C. Hegerl, M. Heimann, B. Hewitson, B.J. Hoskins, F. Joos, J. Jouzel, V. Kattsov, U. Lohmann, T. Matsuno, M. Molina, N. Nicholls, J. Overpeck, G. Raga, V. Ramaswamy, J. Ren, M. Rusticucci, R. Somerville, T.F. Stocker, P. Whetton, R.A. Wood and D. Wratt (2007) Technical Summary. In: *Climate Change 2007: The Physical Science Basis.* Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor, and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Karl, T. et al. (2009).

risks and potential impacts can be characterized with a uniform level of quantification or understanding, nor can they be characterized with uniform metrics. Given this variety in not only the nature and potential magnitude of risks and impacts, but also in our ability to characterize, quantify and project into the future such impacts, the Administrator must use her judgment to weigh the threat in each of the risk categories, weigh the potential benefits where relevant, and ultimately judge whether these risks and benefits, when viewed in total, are judged to be endangerment to public health and/or welfare.

This has a number of implications for the Administrator's approach in assessing the nature and magnitude of risk and impacts across each of the risk categories. First, the Administrator has not established a specific threshold metric for each category of risk and impacts. Also, the Administrator is not necessarily placing the greatest weight on those risks and impacts which have been the subject of the most study or quantification.

Part of the variation in risks and impacts is the fact that climbing atmospheric concentrations of greenhouse gases and associated temperature increases can bring about some potential benefits to public health and welfare in addition to adverse risks. The current understanding of any potential benefits associated with human-induced climate change is described in the TSD and is taken into consideration here. The potential for both adverse and beneficial effects are considered, as well as the relative magnitude of such effects, to the extent that the relative magnitudes can be quantified or characterized. Furthermore, given the multiple ways in which the buildup of atmospheric greenhouse gases can cause effects (*e.g.,* via elevated carbon dioxide concentrations, via temperature increases, via precipitation increases, via sea level rise, and via changes in extreme events), these multiple pathways are considered. For example, elevated carbon dioxide concentrations may be beneficial to crop yields, but changes in temperature and precipitation may be adverse and must also be considered. Likewise, modest temperature increases may have some public health benefits as well as harms, and other pathways such as changes in air quality and extreme events must also be considered.

The Administrator has balanced and weighed the varying risks and effects for each sector. She has judged whether there is a pattern across the sector that supports or does not support an endangerment finding, and if so whether the support is of more or less weight. In cases where there is both a potential for benefits and risks of harm, the Administrator has balanced these factors by determining whether there appears to be any directional trend in the overall evidence that would support placing more weight on one than the other, taking into consideration all that is known about the likelihood of the various risks and effects and their seriousness. In all of these cases, the judgment is largely qualitative in nature, and is not reducible to precise metrics or quantification.

Regarding the timeframe for the endangerment test, it is the Administrator's view that both current and future conditions must be considered. The Administrator is thus taking the view that the endangerment period of analysis extend from the current time to the next several decades, and in some cases to the end of this century. This consideration is also consistent with the timeframes used in the underlying scientific assessments. The future timeframe under consideration is consistent with the atmospheric lifetime and climate effects of the six well-mixed greenhouse gases, and also with our ability to make reasonable and plausible projections of future conditions.

The Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others. Our state of knowledge is strongest for recently observed, large-scale changes. Uncertainty tends to increase in characterizing changes at smaller (regional) scales relative to large (global) scales. Uncertainty also increases as the temporal scales move away from present, either backward, but more importantly forward in time. Nonetheless, the current state of knowledge of observed and past climate changes and their causes enables projections of plausible future changes under different scenarios of anthropogenic forcing for a range of spatial and temporal scales.

In some cases, where the level of sensitivity to climate of a particular sector has been extensively studied, future impacts can be quantified whereas in other instances only a qualitative description of a directional change, if that, may be possible. The inherent uncertainty in the direction, magnitude, and/or rate of certain future climate change impacts opens up the possibility that some changes could be more or less severe than expected, and the possibility of unanticipated outcomes. In some cases, low probability, high impact outcomes (*i.e.,* known unknowns) are possibilities but cannot be explicitly assessed.

1. The Air Pollution Is Reasonably Anticipated To Endanger Public Health

The Administrator finds that the well-mixed greenhouse gas air pollution is reasonably anticipated to endanger public health, for both current and future generations. The Administrator finds that the public health of current generations is endangered and that the threat to public health for both current and future generations will likely mount over time as greenhouse gases continue to accumulate in the atmosphere and result in ever greater rates of climate change.

After review of public comments, the Administrator continues to believe that climate change can increase the risk of morbidity and mortality and that these public health impacts can and should be considered when determining endangerment to public health under CAA section 202(a). As described in Section IV.B.1 of these Findings, the Administrator is not limited to only considering whether there are any direct health effects such as respiratory or toxic effects associated with exposure to greenhouse gases.

In making this public health finding, the Administrator considered direct temperature effects, air quality effects, the potential for changes in vector-borne diseases, and the potential for changes in the severity and frequency of extreme weather events. In addition, the Administrator considered whether and how susceptible populations may be particularly at risk. The current state of science on these effects from the major assessment reports is described in greater detail in the TSD, and our responses to public comments are provided in the Response to Comments Documents.

a. Direct Temperature Effects

It has been estimated that unusually hot days and heat waves are becoming more frequent, and that unusually cold days are becoming less frequent, as noted above. Heat is already the leading cause of weather-related deaths in the United States. In the future, severe heat waves are projected to intensify in magnitude and duration over the portions of the United States where these events already occur. Heat waves are associated with marked short-term increases in mortality. Hot temperatures have also been associated with increased morbidity. The projected warming is therefore projected to increase heat related mortality and morbidity, especially among the elderly, young and frail. The populations most sensitive to hot temperatures are older adults, the chronically sick, the very young, city-dwellers, those taking medications that disrupt thermoregulation, the mentally ill, those lacking access to air conditioning, those working or playing outdoors, and socially isolated persons. As warming increases over time, these adverse effects would be expected to increase as the serious heat events become more serious.

Increases in temperature are also expected to lead to some reduction in the risk of death related to extreme cold. Cold waves continue to pose health risks in northern latitudes in temperature regions where very low temperatures can be reached in a few hours and extend over long periods. Globally, the IPCC projects reduced human mortality from cold exposure through 2100. It is not clear whether reduced mortality in the United States from cold would be greater or less than increased heat-related mortality in the United States due to climate change. However, there is a risk that projections of cold-related deaths, and the potential for decreasing their numbers due to warmer winters, can be overestimated unless they take into account the effects of season and influenza, which is not strongly associated with monthly winter temperature. In addition, the latest USGCRP report refers to a study that analyzed daily mortality and weather data in 50 U.S. cities from 1989 to 2000 and found that, on average, cold snaps in the United States increased death rates by 1.6 percent, while heat waves triggered a 5.7 percent increase in death rates. The study concludes that increases in heat-related mortality due to global warming in the United States are unlikely to be compensated for by decreases in cold-related mortality.

b. Air Quality Effects

Increases in regional ozone pollution relative to ozone levels without climate change are expected due to higher temperatures and weaker circulation in the United States relative to air quality levels without climate change. Climate change is expected to increase regional ozone pollution, with associated risks in respiratory illnesses and premature death. In addition to human health effects, tropospheric ozone has significant adverse effects on crop yields, pasture and forest growth, and species composition. The directional effect of climate change on ambient particulate matter levels remains less certain.

Climate change can affect ozone by modifying emissions of precursors, atmospheric chemistry, and transport and removal. There is now consistent evidence from models and observations that 21st century climate change will worsen summertime surface ozone in polluted regions of North America compared to a future with no climate change.

Modeling studies discussed in EPA's Interim Assessment[28] show that simulated climate change causes increases in summertime ozone concentrations over substantial regions of the country, though this was not uniform, and some areas showed little change or decreases, though the decreases tend to be less pronounced than the increases. For those regions that showed climate-induced increases, the increase in maximum daily 8-hour average ozone concentration, a key metric for regulating U.S. air quality, was in the range of 2 to 8 ppb, averaged over the summer season. The increases were substantially greater than this during the peak pollution episodes that tend to occur over a number of days each summer. The overall effect of climate change was projected to increase ozone levels, compared to what would occur without this climate change, over broad areas of the country, especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems. Ozone decreases are projected to be less pronounced, and generally to be limited to some regions of the country with smaller population.

c. Effects on Extreme Weather Events

In addition to the direct effects of temperature on heat- and cold-related mortality, the Administrator considers the potential for increased deaths, injuries, infectious diseases, and stress-related disorders and other adverse effects associated with social disruption and migration from more frequent extreme weather. The Administrator notes that the vulnerability to weather disasters depends on the attributes of the people at risk (including where they live, age, income, education, and disability) and on broader social and environmental factors (level of disaster preparedness, health sector responses, and environmental degradation). The IPCC finds the following with regard to extreme events and human health:

Increases in the frequency of heavy precipitation events are associated with increased risk of deaths and injuries as well as infectious, respiratory, and skin diseases. Floods are low-probability, high-impact events that can overwhelm physical infrastructure, human resilience, and social organization. Flood health impacts include deaths, injuries, infectious diseases, intoxications, and mental health problems.

Increases in tropical cyclone intensity are linked to increases in the risk of deaths, injuries, waterborne and food borne diseases, as well as post-traumatic stress disorders. Drowning by storm surge, heightened by rising sea levels and more intense storms (as projected by IPCC), is the major killer in coastal storms where there are large numbers of deaths. Flooding can cause health impacts including direct injuries as well as increased incidence of waterborne diseases due to pathogens such as *Cryptosporidium and Giardia.*

d. Effects on Climate-Sensitive Diseases and Aeroallergens

According to the assessment literature, there will likely be an increase in the spread of several food and water-borne pathogens among susceptible populations depending on the pathogens' survival, persistence, habitat range and transmission under changing climate and environmental conditions. Food borne diseases show some relationship with temperature, and the range of some zoonotic disease carriers such as the Lyme disease carrying tick may increase with temperature.

Climate change, including changes in carbon dioxide concentrations, could impact the production, distribution, dispersion and allergenicity of aeroallergens and the growth and distribution of weeds, grasses, and trees that produce them. These changes in aeroallergens and subsequent human exposures could affect the prevalence and severity of allergy symptoms. However, the scientific literature does not provide definitive data or conclusions on how climate change might impact aeroallergens and subsequently the prevalence of allergenic illnesses in the United States.

It has generally been observed that the presence of elevated carbon dioxide concentrations and temperatures stimulate plants to increase photosynthesis, biomass, water use efficiency, and reproductive effort. The IPCC concluded that pollens are likely to increase with elevated temperature and carbon dioxide.

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[28] U.S. EPA (2009) *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone.* An Interim Report of the U.S. EPA Global Change Research Program. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–07/094.

e. Summary of the Administrator's Finding of Endangerment to Public Health

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public health by evaluating the risks associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food and water borne pathogens, and changes in aeroallergens. The evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding. Increases in ambient ozone are expected to occur over broad areas of the country, and they are expected to increase serious adverse health effects in large population areas that are and may continue to be in nonattainment. The evaluation of the potential risks associated with increases in ozone in attainment areas also supports such a finding.

The impact on mortality and morbidity associated with increases in average temperatures which increase the likelihood of heat waves also provides support for a public health endangerment finding. There are uncertainties over the net health impacts of a temperature increase due to decreases in cold-related mortality, but there is some recent evidence that suggests that the net impact on mortality is more likely to be adverse, in a context where heat is already the leading cause of weather-related deaths in the United States.

The evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be adversely affected by an increase in the severity of coastal storm events due to rising sea levels.

There is some evidence that elevated carbon dioxide concentrations and climate changes can lead to changes in aeroallergens that could increase the potential for allergenic illnesses. The evidence on pathogen borne disease vectors provides directional support for an endangerment finding. The Administrator acknowledges the many uncertainties in these areas. Although these adverse effects, provide some support for an endangerment finding, the Administrator is not placing primary weight on these factors.

Finally, the Administrator places weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to these climate-related health effects.

f. Key Comments on the Finding of Endangerment to Public Health

EPA received many comments on public health issues and the proposed finding of endangerment to public health.

i. EPA's Consideration of the Climate Impacts as Public Health Issues Is Reasonable

Several commenters argue that EPA may only consider the health effects from direct exposure to pollutants in determining whether a pollutant endangers public health. The commenters state that EPA's proposal acknowledges that there is no evidence that greenhouse gases directly cause health effects, citing 74 FR 18901. To support their claim that EPA can only consider health effects that result from direct exposure to a pollutant, commenters cite several sources, discussed below.

Clean Air Act and Legislative History. Several commenters argue that the text of the CAA and the legislative history of the 1977 amendments demonstrate that Congress intended public health effects to relate to risks from direct exposure to a pollutant. They also argue that by considering health effects that result from welfare effects, EPA was essentially combining the two categories into one, contrary to the statute and Congressional intent.

Commenters state that the CAA, including CAA section 202(a)(1), requires EPA to consider endangerment of public health separately from endangerment of public welfare. Commenters note that while the CAA does not provide a definition of public health, CAA section 302(h) addresses the meaning of ''welfare,'' which includes weather and climate. Thus, they argue, Congress has instructed that effects on weather and climate are to be considered as potentially endangering welfare—not human health. They continue that Congress surely knew that weather and climatic events such as flooding and heat waves could affect human health, but Congress nonetheless classified air pollutants' effects on weather and climate as effects on welfare.

Commenters also argue that the legislative history confirms that Congress intended for the definition of ''public health'' to only include the consequences of direct human exposure to ambient air pollutants. They note an early version of section 109(b) would have required only a single NAAQS standard to protect ''public health,'' with the protection of ''welfare'' being a co-benefit of the single standard. Commenters note that the proponents of this early bill explained, ''[i]n many cases, a level of protection of health would take care of the welfare situation'' Sen. Hearing, Subcommittee on Air and Water Pollution, Comm. On Public Works (Mar. 17, 1970) (statement of Dr. Middleton, Comm'r, Nat'l Air Pollution Control Admin., HEW), 1970 Leg. Hist. 1194. Commenters state that the Senate bill that ultimately passed rejected this combined standard, requiring separate national ambient air quality standards and national ambient air quality goals. Commenters contend that Congress intended that the national ambient air quality goals be set ''to protect the public health and welfare from any known or anticipated effects associated with'' air pollution, including the list of ''welfare'' effects currently found in CAA section 302(h), such as effects on water, vegetation, animals, wildlife, weather and climate. Commenters note the Senate Committee Report stated that the national ambient air quality *standards* were created to protect public health, while the national ambient air quality *goals* were intended to address broader issues because ''the Committee also recognizes that man's natural and man-made environment must be preserved and protected. Therefore, the bill provides for the setting of national ambient air quality goals at levels necessary to protect public health and welfare from any known or anticipated adverse effects of air pollution—including effects on soils, water, vegetation, man-made materials, animals, wildlife, visibility, climate, and economic values.'' Commenters argue this statement is clearly the source of the current definition of welfare effects in CAA section 302(h), which also includes ''personal comfort and well being.'' They argue the Senate bill contemplated the NAAQS would include only direct health effects, while the *goals* would encompass effects on both the public health and welfare. Commenters continue that considering both public health effects and welfare effects under a combined standard, as the Administrator attempts to do in the proposed endangerment finding, would resurrect the combined approach to NAAQS that the Senate emphatically rejected.

The commenters also cite language from the House Report in support of their view that Congress only intended that EPA consider direct health effects when assessing endangerment to public health: ''By the words 'cause or contribute to air pollution,' the committee intends to require the Administrator to consider all sources of the contaminant which contributes to air pollution and to consider all sources of exposure to the contaminant—food, water, air, etc.—in determining health risks'' 7 H.R. Rep. No. 95–294, at 49–50 (1977). Commenters also cite language in the Senate Report: ''Knowledge of the relationship between the exposure to many air pollution agents and acute and chronic health effects is sufficient to develop air quality criteria related to such effects'' S. Rep. No. 91–1196, at 7 (1970).

The specific issue here is whether an effect on human health that results from a change in climate should be considered when EPA determines whether the air pollution of well-mixed greenhouse gases is reasonably anticipated to endanger public health. In this case, the air pollution has an effect on climate. For example the air pollution raises surface, air, and water temperatures. Among the many effects that flow from this is the expectation that there will be an increase in the risk of mortality and morbidity associated with increased intensity of heat waves. In addition, there is an expectation that there will be an increase in levels of ambient ozone, leading to increased risk of morbidity and mortality from exposure to ozone. All of these are effects on human health, and all of them are associated with the effect on climate from elevated atmospheric concentrations of greenhouse gases. None of these human health effects are associated with direct exposure to greenhouse gases.

In the past, EPA has not had to resolve the issue presented here, as it has been clear whether the effects relate to public health or relate to public welfare, with no confusion over what category was at issue. In those cases EPA has routinely looked at what effect the air pollution has on people. If the effect on people is to their health, we have considered it an issue of public health. If the effect on people is to their interest in matters other than health, we have considered it public welfare.

For example, there are serious health risks associated with inhalation of ozone, and they have logically been considered as public health issues. Ambient levels of ozone have also raised the question of indirect health benefits through screening of harmful UVB rays. EPA has also considered this indirect health effect of ozone to be a public health issue.[29] Ozone pollution also affects people by impacting their interests in various vegetation through foliar damage to trees, reduced crop yield, adverse impacts on horticultural plants, and the like. EPA has consistently considered these issues when evaluating the public welfare based NAAQS standards under CAA section 109.

In all of these situations the use of the term ''public'' has focused EPA on how people are affected by the air pollution. If the effect on people is to their health then we have considered it a public health issue. If the effect on people is to their interest in matters other than health, then we have treated it as a public welfare issue.

The situation presented here is somewhat unique. The focus again is on the effect the air pollution has on people. Here the effect on people is to their health. However this effect flows from the change in climate and effects on climate are included in the definition of effects on welfare. That raises the issue of how to categorize the health effects—should we consider them when evaluating endangerment to public health? When we evaluate endangerment to public welfare? Or both?

The text of the CAA does not resolve this question. While Congress defined ''effects on welfare,'' it did not define either ''public health'' or ''public welfare''. In addition, the definition of ''effects on welfare'' does not clearly address how to categorize health effects that flow from effects on soils, water, crops, vegetation, weather, climate, or any of the other factors listed in CAA section 302(h). It is clear that effects on climate are an effect on welfare, but the definition does not address whether health impacts that are caused by these changes in climate are also effects on welfare. The health effects at issue are not themselves effects on soils, water, crops, vegetation, weather, or climate. They are instead effects on health. They derive from the effects on climate, but they are not themselves effects on climate or on anything else listed in CAA section 302(h). So the definition of effects on welfare does not address whether an effect on health, which is not itself listed in CAA section 302(h), is also an effect on welfare if it results from an effect on welfare. The text of the CAA also does not address the issue of direct and indirect health effects. Contrary to commenters' assertions, the legislative history does not address or resolve this issue.

In this context, EPA is interpreting the endangerment provision in CAA section 202(a) as meaning that the effects on peoples' health from changes to climate can and should be included in EPA's evaluation of whether the air pollution at issue endangers public health. EPA is not deciding whether these health effects also could or should be considered in evaluating endangerment to public welfare.

The stating of the issue makes the answer seem straightforward. If air pollution causes sickness or death, then these health effects should be considered when evaluating whether the air pollution endangers public health. The term public health is undefined, and by itself this is an eminently reasonable way to interpret it. This focuses on the actual effect on people, as compared to ignoring that and focusing on the pathway from the air pollution to the effect. The question then becomes whether there is a valid basis in the CAA to take the different approach suggested by commenters, an approach contrary to the common sense meaning of public health.

Notably, the term ''public welfare'' is undefined. While it clearly means something other than public health, there is no obvious indication whether Congress intended there to be a clear boundary between the two terms or whether there might be some overlap where some impacts could be considered both a public health and a public welfare impact. Neither the text nor the legislative history resolves this issue. Under either approach, EPA believes the proper interpretation is that these effects on health should be considered when evaluating endangerment to public health.

If we assume Congress intended that effects on public welfare could not include effects on public health and vice versa, then the effects at issue here should most reasonably be considered in the public health category. Indisputably they are health effects, and the plain meaning of the term public health would call for their inclusion in that term. The term public welfare is

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[29] As discussed later, in the past EPA took the position that this kind of potential indirect beneficial impact on public health should not be considered when setting the primary health based NAAQS for ozone. This was not based on the view that it was not a potential public health impact, or that it was a public welfare impact instead of a public health impact. Instead EPA was interpreting the NAAQS standard setting provisions of section 109, and argued that they were intended to address only certain public health impacts, those that were adverse, and were not intended to address indirect, beneficial public health impacts. This interpretation of section 109 was rejected in *ATA* v. *EPA*, 175 F.3d 1027 (1999) *reh'g granted in part and denied in part*, 195 F.3d 4 (DC Cir. 1999). The court made it clear that the potential indirect beneficial impact of ambient ozone on public health from screening UVB rays needed to be considered when setting the NAAQS to protect public health.

undefined. If Congress intended that public welfare not include matters included in the public health category, then a reasonable interpretation of this undefined term would include those effects on welfare that impact people in ways other than impacting their health.

The definition of ''effects on welfare'' does not clearly address how to categorize health effects that flow from effects on water, soil, land, climate, or weather. As noted above, the definition does not address whether health impacts that are caused by these changes in climate are also ''effects on welfare.'' Certainly effects on health are not included in the list in CAA section 302(h). The lack of clarity in the definition of effects on welfare, combined with the lack of definition of public welfare, do not warrant interpreting the term public health differently from its straightforward and common sense meaning.

The inclusion of the phrase ''effects on * * * personal comfort and well-being'' as an effect on welfare supports this view. The term would logically mean something other than the different term public health. The term ''well-being'' is not defined, and generally has a broader and different connotation of positive physical, emotional, and mental status. The most straightforward meaning of this term, in a context where Congress used the different term public health in a wide variety of other provisions, would be to include effects on people that do not rise to the level of health effects, but otherwise impact their physical, emotional, and mental status. This gives full meaning to both terms.

The term well-being is a general term, and in isolation arguably could include health effects. However there is no textual basis to say it would include some health effects but not others, as argued by commenters. If sickness impacts your well-being, then it impacts your well-being whether it results directly or indirectly from the pollution in the air. Nothing in CAA section 302(h) limits the term well-being to indirect impacts on people, or to health effects that occur because of other welfare effects, such as climate change. It is listed as its own effect on welfare. Instead of interpreting well-being as including all health effects, or some health effects, the much more logical way to interpret this provision in the context of all of the other provisions of the CAA is to interpret it as meaning effects on people other than health effects.

Thus, if Congress intended to draw a strict line between the two categories of public health and public welfare, for purposes of determining endangerment under CAA section 202(a), then EPA believes that its interpretation is a reasonable and straightforward way to categorize the health effects at issue here. This gives weight to the common sense meaning of the term public health, where the terms public health and public welfare are undefined and the definition of effects on welfare is at best ambiguous on this issue.

In the alternative, if Congress did not intend any such bright line between these two categories and there could be an overlap, then it is also reasonable for EPA to include these health effects in its consideration of whether the air pollution endangers public health. Neither approach condenses or conflates the two different terms. Under either approach EPA's interpretation, as demonstrated in this rulemaking, would still consider numerous and varied effects from climate change as indisputable impacts on public welfare and not impacts on public health. In addition, this interpretation will not change the fact that in almost all cases impacts on public health would not also be considered impacts on public welfare.

Prior EPA actions. Several commenters argue that EPA's decision to include health impacts that occur because of climate change is inconsistent with its past approach, which has been to treat indirect health effects as welfare effects. Commenters contend that in the latest Criteria Document for ozone EPA listed tropospheric ozone's effects on UVB-induced human diseases, as well as its effects on climate change, as welfare effects, even though the agency acknowledged significant health effects such as sunburn and skin cancer. Commenters also argue that EPA listed ''risks to human health'' from toxins released by algal blooms due to excess nitrogen as ''ecological and other welfare effects'' in the recent Criteria Document for oxides of nitrogen and sulfur. Finally, commenters argue that EPA's proposed action was contrary to the Agency decision to list new municipal solid waste landfills as a source category under CAA section 111. Commenters state that EPA listed climate change as a welfare effect in that action, (citing 56 FR 24469).

The Agency's recent approach regarding UVB-induced health effects is consistent with the endangerment findings, and demonstrates that the Agency considers indirect effects on human health as public health issues rather than public welfare issues. While the ozone Criteria Document may have placed the discussion of UV–B related health effects among chapters on welfare effects, in evaluating the evidence presented in the Criteria Document for purposes of preparing the policy assessment document, EPA staff clearly viewed UVB-induced effects as human health effects that were relevant in determining the public health based primary NAAQS for ozone, rather than welfare effects, regardless of which chapter in the Criteria Document described those effects. The evaluation of the UVB-related evidence is discussed with other human health effects evidence. The policy assessment document noted that Chapter 10 of the Criteria Document, ''provides a thorough analysis of the current understanding of the relationship between reducing tropospheric [ozone] concentrations and the potential impact these reductions might have on UV–B surface fluxes and *indirectly contributing to increased UV–B related health effects.'' See*, *Review of the National Ambient Air Quality Standards for Ozone: Policy Assessment of Scientific and Technical Information*, p 3–36 (January 2007) (emphasis added).

EPA repeated this view in the 2007 proposed ozone NAAQS rule. In presenting its evaluation of the human health evidence for purposes of setting the public health based primary NAAQS, EPA stated: ''This section also summarizes the uncertainty about the *potential indirect effects on public health* associated with changes due to increases in UV–B radiation exposure, such as UV–B radiation-related skin cancers, that may be associated with reductions in ambient levels of ground-level [ozone], as discussed in chapter 10 of the Criteria Document and chapter 3 of the Staff Paper.'' 72 FR 37818, 37827. *See* also, 72 FR 37837 (''* * * the Criteria Document also assesses the potential indirect effects related to the presence of [ozone] in the ambient air by considering the role of ground-level [ozone] in mediating human health effects that may be directly attributable to exposure to solar ultraviolet radiation (UV–B).'')

Thus, EPA's approach to UV–B related health effects clearly shows the Agency has treated indirect health effects not as welfare effects, as commenters suggest, but as human health effects that need to be evaluated when setting the public health based primary NAAQS. In this ozone NAAQS rulemaking, EPA did not draw a line between direct and indirect health effects for purposes of evaluating UV–B related health effects and the public health based primary NAAQS.

Similarly, the NO_X/SO_X criteria document does not establish a precedent that indirect human health effects are welfare effects. Toxic algal blooms themselves are a welfare effect, so it is not surprising a discussion of algal blooms appears in sections dealing with welfare effects. The more relevant question is how EPA evaluated information regarding human health risks resulting from algal blooms. In the case of the Criteria Document, the role of nitrogen in causing algal blooms was unclear. As a result, the Agency did not have occasion to evaluate any resulting human health effects and the Criteria Document does not support the view that EPA treats indirect health effects as anything other than a public health issue.

Finally, EPA disagrees that its action here is at odds with the listing of municipal solid waste landfills under CAA section 111. In the landfills New Source Performance Standard (NSPS) EPA did not consider health effects resulting from climate change much less draw any conclusions about health effects from climate change being health or welfare effects. If anything, the landfills NSPS is consistent with EPA's approach. In the proposed rule, EPA stated: ''The EPA has documented many cases of acute injury and death caused by explosions and fires related to municipal landfill gas emissions. In addition to these health effects, the associated property damage is a welfare effect'' (56 FR 24474). EPA considered injury and death from fires resulting from landfill gasses to be health effects. Yet the injury did not result from direct exposure to the pollutant (landfill gas). Instead, the injury resulted from the combustion of the pollutant—the injury is essentially an indirect effect of the pollutant. Yet, as with this action, EPA considered the injury as a human health effect.

Case law. Several commenters argue that EPA's proposed endangerment finding was inconsistent with *NRDC* v. *EPA*, 902 F.2d 962 (DC Cir 1990). Commenters argue that in rejecting the argument that EPA must consider the health effects of increased unemployment that could result from a more stringent primary NAAQS standard, the DC Circuit explained that, ''[i]t is only the health effects relating to pollutants in the air that EPA may consider.'' *Id.* at 973. Several commenters further argue that EPA later relied on that holding to defend its decision to set a primary NAAQS for ozone based solely on direct health effects of ozone. Citing, *EPA Pet'n for Rehearing, Am. Trucking Ass'n* v. *EPA*, No. 97–1440 (DC Cir. June 28, 1999) (''ATA I'') (arguing that the primary NAAQS should be set through consideration of only ''direct adverse effects on public health, and not indirect, allegedly beneficial effects.'')

The *NRDC* case is not contrary to EPA's endangerment finding. In *NRDC*, petitioner American Iron and Steel Institute argued that EPA had to consider the costs of health consequences that might arise from increased unemployment. The court ruled that, ''[c]onsideration of costs associated with alleged health risks from unemployment would be flatly inconsistent with the statute, legislative history and case law on this point.'' 902 F.2d at 973. The cases cited by the court in support of its decision all hold that EPA may not consider economic or technological feasibility in establishing a NAAQS. The *NRDC* decision does not establish a precedent that the CAA prohibits EPA from considering indirect health effects as a public health issue rather than a public welfare issue.

EPA also believes reliance on the Agency's petition for rehearing in noted above is misplaced. In that case, EPA did not argue that indirect beneficial health effects were not public health issues. Instead EPA argued that under the CAA, it did not have to consider such indirect beneficial health effects of an air pollutant when setting the health based primary NAAQS. EPA was interpreting the NAAQS standard setting provisions of CAA section 109, and argued that they were intended to address only certain public health impacts, those that were adverse, and were not intended to address indirect, beneficial public health impacts. The issue in the case was not whether indirect health effects are relevant for purposes of making an endangerment decision concerning public health, but rather whether EPA must consider such beneficial health effects in establishing a primary NAAQS under CAA section 109. EPA's interpretation of CAA section 109 was rejected in *ATA* v. *EPA*, 175 F.3d at 1027 (1999) *reh'g granted in part and denied in part*, 195 F.3d at 4 (DC Cir. 1999). The court made it clear that the potential indirect beneficial impact of ambient ozone on public health from screening UVB rays needed to be considered when setting the NAAQS to protect public health. As discussed above, EPA has done just that as noted above in the UV–B context. Moreover, as discussed in Section II of these Findings, EPA is doing that here as well (*e.g.*, considering any benefits from reduced cold weather related deaths).

ii. EPA's Treatment and Balancing of Heat- vs. Cold-Related Public Health Risks Was Reasonable

A number of public commenters maintain that the risk of heat waves in the future will be modulated by adaptive measures. The Administrator is aware of the potential benefits of adaptation in reducing heat-related morbidity and mortality and recognizes most heat-related deaths are preventable. Nonetheless, the Administrator notes the assessment literature[30] indicates heat is the leading weather-related killer in the United States even though countermeasures have been employed in many vulnerable areas. Given projections for heat waves of greater frequency, magnitude, and duration coupled with a growing population of older adults (among the most vulnerable groups to this hazard), the risk of adverse health outcomes from heat waves is expected to increase. Intervention and response measures could certainly reduce the risk, but as we have noted, the need to adapt supports an increase in risk or endangerment. For a general discussion about EPA's treatment of adaptation see Section III.C of these Findings.

Several commenters also suggest cold-related mortality will decrease more than heat-related mortality will increase, which indicates a net reduction in temperature-related mortality. Some commenters point to research suggesting migration to warmer climates has contributed to the increased longevity of some Americans, implying climate warming will have benefits for health. The Administrator is very clear that the exact balance of how heat- versus cold-related mortality will change in the future is uncertain; however, the assessment literature points to evidence suggesting that the increased risk from heat would exceed the decreased risk from cold in a warming climate. The Administrator does not dispute research indicating the benefits of migration to a warmer climate and nor that average climate warming may indeed provide health benefits in some areas. These points are reflected in the TSD's statement projecting less cold-related health effects. The Administrator considers these potential warming benefits independent of the potential negative effects of extreme heat events which are projected to increase under future climate change scenarios affecting vulnerable groups and communities.

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[30] Karl *et al.* (2009).

iii. EPA Was Reasonable To Find That the Air Quality Impacts of Climate Change Contribute to the Endangerment of Public Health

Several commenters suggest that air quality effects of climate change will be addressed through the CAA's NAAQS process, as implemented by the State Implementation Plans (SIP) and national regulatory programs. According to these commenters, these programs will ensure no adverse impact on public health due to climate change. Though climate change may cause certain air pollutant ambient concentrations to increase, States will continue to be compelled to meet the standards. So, while additional measures may be necessary, and result in increased costs, these commenters assert that, ultimately, public health will be protected by the continued existence of the NAAQS and therefore no endangerment with respect to this particular climate change-related impact will occur. One commenter states that EPA inappropriately assigns air quality risk to climate change that will be addressed through other programs. The CAA provides a mechanism to meet the standards and additional control measures consistent with the CAA will be adopted in the future, keeping pollution below unhealthy levels. The commenters state that the fact that NAAQS are in place that require EPA to fulfill its legal obligation to prevent this particular form of endangerment to public health.

EPA does have in place NAAQS for ozone, which are premised on the harmfulness of ozone to public health and welfare. These standards and their accompanying regulatory regime have helped to reduce the dangers from ozone in the United States. However, substantial challenges remain with respect to achieving the air quality protection promised by the NAAQS for ozone. It is the Administrator's view that these challenges will be exacerbated by climate change.

In addition, the control measures to achieve attainment with a NAAQS are a mitigation measure aimed at reducing emissions of ozone precursors. As discussed in Section III.C of these Findings, EPA is not considering the impacts of mitigation with respect to future reductions in emissions of greenhouse gases. For the same reasons, EPA is reasonably not considering mitigation in the form of the control measures that will need to be adopted in the future to reduce emissions of ozone precursors and thereby address the increased ambient ozone levels that can occur because of climate change.

It is important to note that controls to meet the NAAQS are typically put in place only *after* air quality concentrations exceeding the standard are detected. Furthermore, implementation of controls to reduce ambient concentrations of pollutants occurs over an extended time period, ranging from three years to more than twenty years depending on the pollutant and the seriousness of the nonattainment problem. Thus, while the CAA provides mechanisms for addressing adverse health effects and the underlying air quality exacerbation over time, it will not prevent the adverse impacts in the interim. Given the serious nature of the health effects at issue—including respiratory and cardiovascular disease leading to hospital admissions, emergency department visits, and premature mortality—this increase in adverse impacts during the time before additional controls can be implemented is a serious public health concern. Historically, a large segment of the U.S. population has lived in areas exceeding the NAAQS, despite the CAA and its implementation efforts. Half of all Americans, 158 million people, live in counties where air pollution exceeds national health standards.[31] Where attainment of the NAAQS is especially difficult, leading to delays in meeting attainment deadlines, the health effects of increased ozone due to climate change may be substantial.

It is also important to note that it may not be possible for States and Tribes to plan accurately for the impacts of climate change in developing control strategies for nonattainment areas. As noted in the TSD and EPA's 2009 Interim Assessment report (IA), climate change is projected to lead to an increase in the variability of weather, and this may increase peak pollution events including increases in ozone exceedances. While the modeling studies in the IA all show significant future changes in meteorological quantities, there is also significant variability across the simulations in the spatial patterns of these future changes, making it difficult to select a set of future meteorological data for planning purposes. At this time, models used to develop plans to attain the NAAQS do not take potential changes in future meteorology into consideration. Inability to predict the frequency and magnitude of such events could lead to an underestimation of the controls needed to bring areas into attainment, and a prolonged period during which adverse health impacts continue to occur.

Even in areas that meet the NAAQS currently, air quality may deteriorate sufficiently to cause adverse health effects for some individuals. Some at-risk individuals, for example those with preexisting health conditions or other characteristics which increase their risk for adverse effects upon exposure to PM or ozone, may experience health effects at levels below the standard. Current evidence suggests that there is no threshold for PM or ozone concentrations below which no effects can be observed. Therefore, increases in ozone or PM in locations that currently meet the standards would likely result in additional adverse health effects for some individuals, even though the pollution increase might not be sufficient to cause the area to be designated nonattainment. While the NAAQS is set to protect public health with an adequate margin of safety, it is recognized that in attainment areas there may be individuals who remain at greater risk from an increase in ozone levels. The clear risk to the public from ozone increases in nonattainment areas, in combination with the risk to some individuals in attainment areas, supports the finding that overall the public health is endangered by increases in ozone resulting from climate change.

Finally, it is also important to note that not all air pollution events are subject to CAA controls under the NAAQS implementation provisions. ''Exceptional events'' are events for which the normal planning and regulatory process established by the CAA is not appropriate (72 FR 13561). Emissions from some events, including some wildfires, are not reasonably controllable or preventable. Such emissions, however, can adversely impact public health and welfare and are expected to increase due to climate change. As described in the TSD, PM emissions from wildfires can contribute to acute and chronic illnesses of the respiratory system, particularly in children, including pneumonia, upper respiratory diseases, asthma and chronic obstructive pulmonary disease. The IPCC (Field et al., 2007) reported with very high confidence that in North America, disturbances like wildfires are increasing and are likely to intensify in a warmer future with drier soils and longer growing seasons.

2. The Air Pollution Is Reasonably Anticipated to Endanger Public Welfare

The Administrator also finds that the well-mixed greenhouse gas air pollution may reasonably be anticipated to

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[31] U.S. EPA (2008) National Air Quality: Status and Trends Through 2007. EPA–454/R–08–006, November 2008.

endanger public welfare, both for current and future generations.

As with public health, the Administrator considered the multiple pathways in which the greenhouse gas air pollution and resultant climate change affect climate-sensitive sectors, and the impact this may have on public welfare. These sectors include food production and agriculture; forestry; water resources; sea level rise and coastal areas; energy, infrastructure, and settlements; and ecosystems and wildlife. The Administrator also considered impacts on the U.S. population from climate change effects occurring outside of the United States, such as national security concerns for the United States that may arise as a result of climate change impacts in other regions of the world. The Administrator examined each climate-sensitive sector individually, informed by the summary of the scientific assessments contained in the TSD, and the full record before EPA, and weighed the extent to which the risks and impacts within each sector support or do not support a positive endangerment finding in her judgment. The Administer then viewed the full weight of evidence looking across all sectors to reach her decision regarding endangerment to public welfare.

a. Food Production and Agriculture

Food production and agriculture within the United States is a sector that will be affected by the combined effects of elevated carbon dioxide concentrations and associated climate change. The Administrator considered how these effects, both adverse and beneficial, are affecting the agricultural sector now and in the future, and over different regions of the United States, taking into account that different regions of the country specialize in different agricultural products with varying degrees of sensitivity and vulnerability to elevated carbon dioxide levels and associated climate change.

Elevated carbon dioxide concentrations can have a stimulatory effect on grain and oilseed crop yield, as may modest temperature increases and a longer growing season that results. A report under the USGCRP concluded that, with increased carbon dioxide and temperature, the life cycle of grain and oilseed crops will likely progress more rapidly. However, such beneficial influences need to be considered in light of various other effects. For example, the literature indicates that elevated carbon dioxide concentrations may also enhance pest and weed growth. Pests and weeds can reduce crop yields, cause economic losses to farmers, and require management control options. How climate change (elevated carbon dioxide, increased temperatures, altered precipitation patterns, and changes in the frequency and intensity of extreme events) may affect the prevalence of pests and weeds is an issue of concern for food production and the agricultural sector. Research on the combined effects of elevated carbon dioxide and climate change on pests, weeds, and disease is still limited. In addition, higher temperature increases, changing precipitation patterns and variability, and any increases in ground-level ozone induced by higher temperatures, can work to counteract any direct stimulatory carbon dioxide effect, as well as lead to their own adverse impacts. There may be large regional variability in the response of food production and agriculture to climate change.

For grain and oilseed crop yields, there is support for the view that in the near term climate change may have a beneficial effect, largely through increased temperature and increased carbon dioxide levels. However there are also factors noted above, some of which are less well studied and understood, which would tend to offset any near term benefit, leaving significant uncertainty about the actual magnitude of any overall benefit. The USGCRP report also concluded that as temperature rises, these crops will increasingly begin to experience failure, especially if climate variability increases and precipitation lessens or becomes more variable.

A key uncertainty is how human-induced climate change may affect the intensity and frequency of extreme weather events such as droughts and heavy storms. These events have the potential to have serious negative impact on U.S. food production and agriculture, but are not always taken into account in studies that examine how average conditions may change as a result of carbon dioxide and temperature increases. Changing precipitation patterns, in addition to increasing temperatures and longer growing seasons, can change the demand for irrigation requirements, potentially increasing irrigation demand.

Another key uncertainty concerns the many horticultural crops (*e.g.,* tomatoes, onions, fruits), which make up roughly 40 percent of total crop value in the United States. There is relatively little information on their response to carbon dioxide, and few crop simulation models, but according to the literature, they are very likely to be more sensitive to the various effects of climate change than grain and oilseed crops.

With respect to livestock, higher temperatures will very likely reduce livestock production during the summer season in some areas, but these losses will very likely be partially offset by warmer temperatures during the winter season. The impact on livestock productivity due to increased variability in weather patterns will likely be far greater than effects associated with the average change in climatic conditions. Cold-water fisheries will likely be negatively affected; warm-water fisheries will generally benefit; and the results for cool-water fisheries will be mixed, with gains in the northern and losses in the southern portions of ranges.

Finally, with respect to irrigation requirements, the adverse impacts of climate change on irrigation water requirements may be significant.

There is support for the view that there may be a benefit in the near term in the crop yield for certain crops. This potential benefit is subject to significant uncertainty, however, given the offsetting impact on the yield of these crops from a variety of other climate change impacts that are less well understood and more variable. Any potential net benefit is expected to change to a disbenefit in the longer term. In addition, there is clear risk that the sensitivity of a major segment of the total crop market, the horticultural sector, may lead to adverse affects from climate change. With respect to livestock production and irrigation requirements, climate change is likely to have adverse effects in both the near and long terms. The impact on fisheries varies, and would appear to be best viewed as neutral overall.

There is a potential for a net benefit in the near term for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector are expected to be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops.

However, considering the trend over near- and long-term future conditions, the Administrator finds that the body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture, with the potential for significant disruptions and crop failure in the future.

b. Forestry

The factors that the Administrator considered for the U.S. forest sector are similar to those for food production and agriculture. There is the potential for beneficial effects due to elevated concentrations of carbon dioxide and increased temperature, as well as the potential for adverse effects from increasing temperatures, changing precipitation patterns, increased insects and disease, and the potential for more frequent and severe extreme weather events. The potential beneficial effects are better understood and studied, and are limited to certain areas of the country and types of forests. The adverse effects are less certain, more variable, and also include some of the most serious adverse effects such as increased wildfire, drought, and major losses from insects and disease. As with food production and agriculture, the judgment to be made is largely a qualitative one, balancing impacts that vary in certainty and magnitude, with the end result being a judgment as to the overall direction and general level of concern.

According to the underlying science assessment reports, climate change has very likely increased the size and number of wildfires, insect outbreaks, and tree mortality in the Interior West, the Southwest, and Alaska, and will continue to do so. Rising atmospheric carbon dioxide levels will very likely increase photosynthesis for forests, but the increased photosynthesis will likely only increase wood production in young forests on fertile soils. Nitrogen deposition and warmer temperatures have very likely increased forest growth where water is not limiting and will continue to do so in the near future.

An increased frequency of disturbance (such as drought, storms, insect-outbreaks, and wildfire) is at least as important to forest ecosystem function as incremental changes in temperature, precipitation, atmospheric carbon dioxide, nitrogen deposition, and ozone pollution. Disturbances partially or completely change forest ecosystem structure and species composition, cause short-term productivity and carbon storage loss, allow better opportunities for invasive alien species to become established, and command more public and management attention and resources. The combined effects of expected increased temperature, carbon dioxide, nitrogen deposition, ozone, and forest disturbance on soil processes and soil carbon storage remain unclear.

Precipitation and weather extremes are key to many forestry impacts, accounting for part of the regional variability in forest response. If existing trends in precipitation continue, it is expected that forest productivity will likely decrease in the Interior West, the Southwest, eastern portions of the Southeast, and Alaska, and that forest productivity will likely increase in the northeastern United States, the Lake States, and in western portions of the Southeast. An increase in drought events will very likely reduce forest productivity wherever such events occur.

Changes in disturbance patterns are expected to have a substantial impact on overall gains or losses. More prevalent wildfire disturbances have recently been observed in the United States. Wildfires and droughts, among other extreme events (*e.g.,* hurricanes) that can cause forest damage, pose the largest threats over time to forest ecosystems.

For the near term, the Administrator believes the beneficial impact on forest growth and productivity in certain parts of the country from climate change to be more than offset by the clear risk from the more significant and serious adverse effects from the observed increases in wildfires, combined with the adverse impacts on growth and productivity in other areas of the country and the serious risks from the spread of destructive pests and disease. Increased wildfires can also increase particulate matter and thus create public health concerns as well. For the longer term, the Administrator views the risk from adverse effects to increase over time, such that overall climate change presents serious adverse risks for forest productivity. The Administrator therefore finds there is compelling reason to find that the greenhouse gas air pollution endangers U.S. forestry in both the near and long term, with the support for a positive endangerment finding only increasing as one considers expected future conditions in which temperatures continue to rise.

c. Water Resources

The sensitivity of water resources to climate change is very important given the increasing demand for adequate water supplies and services for agricultural, municipal, and energy and industrial uses, and the current strains on this resource in many parts of the country.

According to the assessment literature, climate change has already altered, and will likely continue to alter, the water cycle, affecting where, when, and how much water is available for all uses. With higher temperatures, the water-holding capacity of the atmosphere and evaporation into the atmosphere increase, and this favors increased climate variability, with more intense precipitation and more droughts.

Climate change is causing and will increasingly cause shrinking snowpack induced by increasing temperature. In the western United States, there is already well-documented evidence of shrinking snowpack due to warming. Earlier meltings, with increased runoff in the winter and early spring, increase flood concerns and also result in substantially decreased summer flows. This pattern of reduced snowpack and changes to the flow regime pose very serious risks to major population regions, such as California, that rely on snowmelt-dominated watersheds for their water supply. While increased precipitation is expected to increase water flow levels in some eastern areas, this may be tempered by increased variability in the precipitation and the accompanying increased risk of floods and other concerns such as water pollution.

Warmer temperatures and decreasing precipitation in other parts of the country, such as the Southwest, can sustain and amplify drought impacts. Although drought has been more frequent and intense in the western part of the United States, the East is also vulnerable to droughts and attendant reductions in water supply, changes in water quality and ecosystem function, and challenges in allocation. The stress on water supplies on islands is expected to increase.

The impact of climate change on groundwater as a water supply is regionally variable; efforts to offset declining surface water availability due to increasing precipitation variability may be hampered by the fact that groundwater recharge will decrease considerably in some already water-stressed regions. In coastal areas, the increased salinization from intrusion of salt water is projected to have negative effects on the supply of fresh water.

Climate change is expected to have adverse effects on water quality. The IPCC concluded with high confidence that higher water temperatures, increased precipitation intensity, and longer periods of low flows exacerbate many forms of water pollution and can impact ecosystems, human health, and water system reliability and operating costs. These changes will also exacerbate many forms of water pollution, potentially making attainment of water quality goals more difficult. Water pollutants of concern that are particularly relevant to climate change effects include sediment, nutrients, organic matter, pathogens, pesticides, salt, and thermal pollution. As waters become warmer, the aquatic life they now support will be replaced by other species better adapted to warmer water. In the long term, warmer water, changing flows, and decreased water quality may result in deterioration of aquatic ecosystems.

Climate change will likely further constrain already over-allocated water resources in some regions of the United States, increasing competition among agricultural, municipal, industrial, and ecological uses. Although water management practices in the United States are generally advanced, particularly in the West, the reliance on past conditions as the basis for current and future planning may no longer be appropriate, as climate change increasingly creates conditions well outside of historical observations. Increased incidence of extreme weather and floods may also overwhelm or damage water treatment and management systems, resulting in water quality impairments. In the Great Lakes and major river systems, lower water levels are likely to exacerbate challenges relating to water quality, navigation, recreation, hydropower generation, water transfers, and bi-national relationships.

The Administrator finds that the total scientific literature provides compelling support for finding that greenhouse gas air pollution endangers the water resources important for public welfare in the United States, both for current and future generations. The adequacy of water supplies across large areas of the country is at serious risk from climate change. Even areas of the country where an increase in water flow is projected could face water resource problems from the variability of the supply and water quality problems associated with precipitation variability, and could face the serious adverse effects from risks from floods and drought. Climate change is expected to adversely affect water quality. There is an increased risk of serious adverse effects from extreme events of flooding and drought. The severity of risks and impacts may only increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

d. Sea Level Rise and Coastal Areas

A large percentage of the U.S. population lives in coastal areas, which are particularly vulnerable to the risks posed by climate change. The most vulnerable areas are the Atlantic and Gulf Coasts, the Pacific Islands, and parts of Alaska.

According to the assessment literature, sea level is rising along much of the U.S. coast, and the rate of change will very likely increase in the future, exacerbating the impacts of progressive inundation, storm-surge flooding, and shoreline erosion. Cities such as New Orleans, Miami, and New York are particularly at risk, and could have difficulty coping with the sea level rise projected by the end of the century under a higher emissions scenario. Population growth and the rising value of infrastructure increases the vulnerability to climate variability and future climate change in coastal areas. Adverse impacts on islands present concerns for Hawaii and the U.S. territories. Reductions in Arctic sea ice increases extreme coastal erosion in Alaska, due to the increased exposure of the coastline to strong wave action. In the Great Lakes, where sea level rise is not a concern, both extremely high and low water levels resulting from changes to the hydrological cycle have been damaging and disruptive to shoreline communities.

Coastal wetland loss is being observed in the United States where these ecosystems are squeezed between natural and artificial landward boundaries and rising sea levels. Up to 21 percent of the remaining coastal wetlands in the U.S. mid-Atlantic region are potentially at risk of inundation between 2000 and 2100. Coastal habitats will likely be increasingly stressed by climate change impacts interacting with development and pollution.

Although increases in mean sea level over the 21st century and beyond will inundate unprotected, low-lying areas, the most devastating impacts are likely to be associated with storm surge. Superimposed on expected rates of sea level rise, projected storm intensity, wave height, and storm surge suggest more severe coastal flooding and erosion hazards. Higher sea level provides an elevated base for storm surges to build upon and diminishes the rate at which low-lying areas drain, thereby increasing the risk of flooding from rainstorms. In New York City and Long Island, flooding from a combination of sea level rise and storm surge could be several meters deep. Projections suggest that the return period of a 100-year flood event in this area might be reduced to 19–68 years, on average, by the 2050s, and to 4–60 years by the 2080s. Additionally, some major urban centers in the United States, such as areas of New Orleans are situated in low-lying flood plains, presenting increased risk from storm surges.

The Administrator finds that the most serious risk of adverse effects is presented by the increased risk of storm surge and flooding in coastal areas from sea level rise. Current observations of sea level rise are now contributing to increased risk of storm surge and flooding in coastal areas, and there is reason to find that these areas are now endangered by human-induced climate change. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense with increasing temperatures (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. The Administrator has concluded that even if there is a low probability of raising the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution.

In addition, coastal areas face other adverse impacts from sea level rise such as shoreline retreat, erosion, wetland loss and other effects. The increased risk associated with these adverse impacts also endangers the welfare of current and future generations, with an increasing risk of greater adverse impacts in the future.

Overall, the evidence on risk of adverse impacts for coastal areas from sea level rise provides clear support for finding that greenhouse gas air pollution endangers the welfare of current and future generations.

e. Energy, Infrastructure and Settlements

The Administrator also considered the impacts of climate change on energy consumption and production, and on key climate-sensitive aspects of the nation’s infrastructure and settlements.

For the energy sector, the Administrator finds clear evidence that temperature increases will change heating and cooling demand, and to varying degrees across the country; however, under current conditions it is unclear whether or not net demand will increase or decrease. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to call for an increase in electricity production, especially supply for peak demand. The U.S. energy sector, which relies heavily on water for cooling capacity and hydropower, may be adversely impacted by changes to water supply in reservoirs and other water bodies.

With respect to infrastructure, climate change vulnerabilities of industry, settlement and society are mainly related to extreme weather events rather than to gradual climate change. The significance of gradual climate change, *e.g.*, increases in the mean temperature, lies mainly in changes in the intensity and frequency of extreme events. Extreme weather events could threaten U.S. energy infrastructure (transmission and distribution), transportation infrastructure (roads, bridges, airports and seaports), water infrastructure, and other built aspects of human settlements. Moreover, soil subsidence caused by the melting of permafrost in the Arctic region is a risk to gas and oil pipelines, electrical transmission towers, roads, and water systems. Vulnerabilities for industry, infrastructures, settlements, and society to climate change are generally greater in certain high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Additionally, infrastructures are often connected, meaning that an impact on one can also affect others.

A significant fraction of U.S. infrastructure is located in coastal areas. In these locations, rising sea levels are likely to lead to direct losses (*e.g.*, equipment damage from flooding) as well as indirect effects such as the costs associated with raising vulnerable assets to higher levels. Water infrastructure, including drinking water and wastewater treatment plants, and sewer and storm water management systems, may be at greater risk of flooding, sea level rise and storm surge, low flows, saltwater intrusion, and other factors that could impair performance and damage costly investments.

Within settlements experiencing climate change stressors, certain parts of the population may be especially vulnerable based on their circumstances. These include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. In Alaska, indigenous communities are likely to experience disruptive impacts, including shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

Overall, the evidence strongly supports the view that climate change presents risks of serious adverse impacts on public welfare from the risk to energy production and distribution as well as risks to infrastructure and settlements.

f. Ecosystems and Wildlife

The Administrator considered the impacts of climate change on ecosystems and wildlife and the services they provide. The Administrator finds clear evidence that climate change is exerting major influences on natural environments and biodiversity, and these influences are generally expected to grow with increased warming. Observed changes in the life cycles of plants and animals include shifts in habitat ranges, timing of migration patterns, and changes in reproductive timing and behavior.

The underlying assessment literature finds with high confidence that substantial changes in the structure and functioning of terrestrial ecosystems are very likely to occur with a global warming greater than 2 to 3 °C above pre-industrial levels, with predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services. With global average temperature changes above 2 °C, many terrestrial, freshwater, and marine species (particularly endemic species) are at a far greater risk of extinction than in the geological past. Climate change and ocean acidification will likely impair a wide range of planktonic and other marine calcifiers such as corals. Even without ocean acidification effects, increases in sea surface temperature of about 1–3 °C are projected to result in more frequent coral bleaching events and widespread mortality. In the Arctic, wildlife faces great challenges from the effects of climatic warming, as projected reductions in sea ice will drastically shrink marine habitat for polar bears, ice-inhabiting seals, and other animals.

Some common forest types are projected to expand, such as oak-hickory, while others are projected to contract, such as maple-beech-birch. Still others, such as spruce-fir, are likely to disappear from the contiguous United States. Changes in plant species composition in response to climate change can increase ecosystem vulnerability to other disturbances, including wildfires and biological invasion. Disturbances such as wildfires and insect outbreaks are increasing in the United States and are likely to intensify in a warmer future with warmer winters, drier soils and longer growing seasons. The areal extent of drought-limited ecosystems is projected to increase 11 percent per °C warming in the United States. In California, temperature increases greater than 2 °C may lead to conversion of shrubland into desert and grassland ecosystems and evergreen conifer forests into mixed deciduous forests. Greater intensity of extreme events may alter disturbance regimes in coastal ecosystems leading to changes in diversity and ecosystem functioning. Species inhabiting salt marshes, mangroves, and coral reefs are likely to be particularly vulnerable to these effects.

The Administrator finds that the total scientific record provides compelling support for finding that the greenhouse gas air pollution leads to predominantly negative consequences for biodiversity and the provisioning of ecosystem goods and services for ecosystems and wildlife important for public welfare in the U.S., both for current and future generations. The severity of risks and impacts may only increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

g. Summary of the Administrator's Finding of Endangerment to Public Welfare

The Administrator has considered how elevated concentrations of the well-mixed greenhouse gases and associated climate change affect public welfare by evaluating numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. For each of these sectors, the evidence provides support for a finding of endangerment to public welfare. The evidence concerning adverse impacts in the areas of water resources and sea level rise and coastal areas provide the clearest and strongest support for an endangerment finding, both for current and future generations. Strong support is also found in the evidence concerning infrastructure and settlements, as well ecosystems and wildlife. Across the sectors, the potential serious adverse impacts of extreme events, such as wildfires, flooding, drought, and extreme weather conditions provide strong support for such a finding.

Water resources across large areas of the country are at serious risk from climate change, with effects on water supplies, water quality, and adverse effects from extreme events such as floods and droughts. Even areas of the country where an increase in water flow is projected could face water resource problems from the supply and water quality problems associated with temperature increases and precipitation variability, and could face the increased risk of serious adverse effects from extreme events, such as floods and drought. The severity of risks and impacts is likely to increase over time with accumulating greenhouse gas concentrations and associated temperature increases and precipitation changes.

Overall, the evidence on risk of adverse impacts for coastal areas provides clear support for a finding that greenhouse gas air pollution endangers the welfare of current and future generations. The most serious potential adverse effects are the increased risk of storm surge and flooding in coastal areas from sea level rise and more intense storms. Observed sea level rise is already increasing the risk of storm surge and flooding in some coastal areas. The conclusion in the assessment literature that there is the potential for hurricanes to become more intense (and even some evidence that Atlantic hurricanes have already become more intense) reinforces the judgment that coastal communities are now endangered by human-induced climate change, and may face substantially greater risk in the future. Even if there is a low probability of increasing the destructive power of hurricanes, this threat is enough to support a finding that coastal communities are endangered by greenhouse gas air pollution. In addition, coastal areas face other adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss. The increased risk associated with these adverse impacts also endangers public welfare, with an increasing risk of greater adverse impacts in the future.

Strong support for an endangerment finding is also found in the evidence concerning energy, infrastructure, and settlements, as well ecosystems and wildlife. While the impacts on net energy demand may be viewed as generally neutral for purposes of making an endangerment determination, climate change is expected to result in an increase in electricity production, especially to meet peak demand. This increase may be exacerbated by the potential for adverse impacts from climate change on hydropower resources as well as the potential risk of serious adverse effects on energy infrastructure from extreme events. Changes in extreme weather events threaten energy, transportation, and water resource infrastructure. Vulnerabilities of industry, infrastructure, and settlements to climate change are generally greater in high-risk locations, particularly coastal and riverine areas, and areas whose economies are closely linked with climate-sensitive resources. Climate change will likely interact with and possibly exacerbate ongoing environmental change and environmental pressures in settlements, particularly in Alaska where indigenous communities are facing major environmental and cultural impacts on their historic lifestyles. Over the 21st century, changes in climate will cause some species to shift north and to higher elevations and fundamentally rearrange U.S. ecosystems. Differential capacities for range shifts and constraints from development, habitat fragmentation, invasive species, and broken ecological connections will likely alter ecosystem structure, function, and services, leading to predominantly negative consequences for biodiversity and the provision of ecosystem goods and services.

With respect to food production and agriculture, there is a potential for a net benefit in the near term for certain crops, but there is significant uncertainty about whether this benefit will be achieved given the various potential adverse impacts of climate change on crop yield, such as the increasing risk of extreme weather events. Other aspects of this sector may be adversely affected by climate change, including livestock management and irrigation requirements, and there is a risk of adverse effect on a large segment of the total crop market. For the near term, the concern over the potential for adverse effects in certain parts of the agriculture sector appears generally comparable to the potential for benefits for certain crops. However, the body of evidence points towards increasing risk of net adverse impacts on U.S. food production and agriculture over time, with the potential for significant disruptions and crop failure in the future.

For the near term, the Administrator finds the beneficial impact on forest growth and productivity in certain parts of the country from elevated carbon dioxide concentrations and temperature increases to date is offset by the clear risk from the observed increases in wildfires, combined with risks from the spread of destructive pests and disease. For the longer term, the risk from adverse effects increases over time, such that overall climate change presents serious adverse risks for forest productivity. There is compelling reason to find that the support for a positive endangerment finding increases as one considers expected future conditions where temperatures continue to rise.

Looking across all of the sectors discussed above, the evidence provides compelling support for finding that greenhouse gas air pollution endangers the public welfare of both current and future generations. The risk and the severity of adverse impacts on public welfare are expected to increase over time.

h. Impacts in Other World Regions That Can Affect the U.S Population

While the finding of endangerment to public health and welfare discussed above is based on impacts in the United States, the Administrator also considered how human-induced climate change in other regions of the world may in turn affect public welfare in the United States. According to the USGCRP report of June 2009 and other sources, climate change impacts in certain regions of the world may exacerbate problems that raise humanitarian, trade, and national security issues for the United States.[32] The IPCC identifies the most vulnerable world regions as the Arctic, because of the effects of high rates of projected warming on natural systems; Africa, especially the sub-Saharan region, because of current low adaptive capacity as well as climate change; small islands, due to high exposure of population and infrastructure to risk of sea-level rise and increased storm surge; and Asian mega-deltas, such as the Ganges-Brahmaputra and the Zhujiang, due to large populations and high exposure to sea level rise, storm surge, and river flooding. Climate change has been described as a potential threat multiplier with regard to national security issues.

The Administrator acknowledges these kinds of risks do not readily lend themselves to precise analyses or future projections. However, given the unavoidable global nature of the climate change problem, it is appropriate and prudent to consider how impacts in other world regions may present risks to the U.S. population. Because human-induced climate change has the potential to aggravate natural resource, trade, and humanitarian issues in other world regions, which in turn may contribute to the endangerment of public welfare in the United States, this provides additional support for the Administrator's finding that the greenhouse gas air pollution is reasonably anticipated to endanger the public welfare of current and future

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[32] ''In an increasingly interdependent world, U.S. vulnerability to climate change is linked to the fates of other nations. For example, conflicts or mass migrations of people resulting from food scarcity and other resource limits, health impacts or environmental stresses in other parts of the world could threaten U.S. national security.'' (Karl *et al.,* 2009).

generations of the United States population.

i. Summary of Key Public Comments on Endangerment to Public Welfare

Several public commenters point out the anticipated benefits that increasing carbon dioxide levels and temperatures will have on agricultural crops. In addition, commenters note how U.S. agricultural productivity, in particular, has been steadily rising over the last 100 years. Responses to major comments are found here and more detailed responses are found in the Response to Comments document.

The Administrator acknowledges that plants including agricultural crops respond to carbon dioxide positively based on numerous well-documented studies. However, previous assessments of food production and agriculture have been modified to highlight increasing vulnerability, stress, and adverse impacts from climate change over time, based on improvements in the understanding of plant physiology, concern over impacts on plant pests and pathogens, and the implications of changes in average temperatures for temperature extremes and for changes in the patterns of precipitation and evaporation. While it is still the case today and for the next few years that climate change benefits agriculture in some places and harms them in others, the Administrator considers that the far larger temperature increases expected over coming decades and beyond on the ''business as usual'' trajectory will put significant stresses on agriculture and land resources in all regions of the United States. The Administrator prudently considers increased climate variability associated with a warming climate, which may overwhelm the positive plant responses from elevated carbon dioxide over time. Further, the effects of climate change on weeds, insect pests, and pathogens are recognized as key factors in determining plant damage in future decades. The Administrator also notes that scientific literature clearly supports the finding that drought frequency and severity are projected to increase in the future over much of the United States, which will likely reduce crop yields because of excesses or deficits of water. Vulnerability to extended drought, according to IPCC, has been documented as already increasing across North America. Further, based on review of the assessment literature, the Administrator considers multiple stresses, such as limited availability of water resources, loss of biodiversity, and air pollution, which are likely to increase sensitivity and reduce resilience in the agricultural sector to climate change over time.

Similar to food production and agriculture, public commenters often noted that forest productivity is projected to increase in the coming years due to the direct stimulatory effect of carbon dioxide on plant growth combined with warmer temperatures and thus extended growing seasons. The Administrator notes this phenomenon has been well documented by numerous studies but recognizes that increased productivity will be associated with significant variation at local and regional scales. The Administrator considers that climate strongly influences forest productivity and composition, and the frequency and magnitude of disturbances that impact forests. Based on the most recent IPCC assessment of the scientific literature, several recent studies confirm previous findings that temperature and precipitation changes in future decades will modify, and often limit, direct carbon dioxide effects on plants. For example, increased temperatures may reduce carbon dioxide effects indirectly, by increasing water demand. The Administrator also considers that new research more firmly establishes the negative impacts of increased climate variability. Projected changes in the frequency and severity of extreme climate events have significant consequences for forestry production and amplify existing stresses to land resources in the future.

Several public commenters maintain that wildfires are primarily the result of natural climatic factors and not climate change and dispute that they are or will increase in the future. The Administrator notes the scientific literature and assessment reports provide several lines of evidence that suggest wildfires will likely increase in frequency over the next several decades because of climate warming. Wildfires and droughts, among other extreme events (*e.g.,* hurricanes) that cause forest damage, pose the largest threats over time to forest ecosystems. The assessment literature suggests that large, stand-replacing wildfires will likely increase in frequency over the next several decades because of climate warming and general climate warming encourages wildfires by extending the summer period that dries fuels, promoting easier ignition and faster spread. Furthermore, current climate modeling studies suggest that increased temperatures and longer growing seasons will elevate wildfire risk in connection with increased aridity.

V. The Administrator's Finding That Emissions of Greenhouse Gases From CAA Section 202(a) Sources Cause or Contribute to the Endangerment of Public Health and Welfare

As discussed in Section IV.A of these Findings, the Administrator is defining the air pollution for purposes of the endangerment finding to be the elevated concentration of well-mixed greenhouse gases in the atmosphere. The second step of the two-part endangerment test is for the Administrator to determine whether the emission of any air pollutant emitted from new motor vehicles cause or contribute to this air pollution. This is referred to as the cause or contribute finding, and is the second finding by the Administrator in this action.

Section V.A of these Findings describes the Administrator's definition and scope of the air pollutant ''well-mixed greenhouse gases.'' Section V.B of these Findings puts forth the Administrator's finding that emissions of well-mixed greenhouse gases from new motor vehicles contribute to the air pollution which is reasonably anticipated to endanger public health and welfare. Section V.C of these Findings provides responses to some of the key comments on these issues. See Response to Comments document Volume 10 for responses to other significant comments on the cause or contribute finding. More detailed emissions data summarized in the discussion below can be found in Appendix B of the TSD.

A. The Administrator's Definition of the ''Air Pollutant''

As discussed in the Proposed Findings, to help appreciate the distinction between air pollution and air pollutant, the *air pollution* can be thought of as the total, cumulative stock in the atmosphere, while the *air pollutant,* can be thought of as the flow that changes the size of the total stock. Given this relationship, it is not surprising that the Administrator is defining the air pollutant similar to the air pollution; while the air pollution is the concentration (*e.g.,* stock) of the well-mixed greenhouse gases in the atmosphere, the air pollutant is the same combined grouping of the well-mixed greenhouse gases, the emissions of which are analyzed for contribution (*e.g.,* the flow into the stock).

Thus, the Administrator is defining the air pollutant as the aggregate group of the same six long-lived and directly-emitted greenhouse gases: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. As noted above, this definition of a single air pollutant made up of these well-mixed greenhouse gases is similar to definitions of other air pollutants that are comprised of substances that share common attributes with similar effects on public health or welfare (*e.g.,* particulate matter and volatile organic compounds).

The common attributes shared by these six greenhouse gases are discussed in detail in Section IV.A of these Findings, where the Administrator defined the ''air pollution'' for purposes of the endangerment finding. These same common attributes support the Administrator grouping these six greenhouse gases for purposes of defining a single air pollutant as well. These attributes include the fact that they are all greenhouse gases that are directly emitted (*i.e.,* they are not formed through secondary processes in the atmosphere from precursor emissions); they are sufficiently long-lived in the atmosphere such that, once emitted, concentrations of each gas become well mixed throughout the entire global atmosphere; and they exert a climate warming effect by trapping outgoing, infrared heat that would otherwise escape to space. Moreover, the radiative forcing effect of these six greenhouse gases is well understood.

Furthermore, these six greenhouse gases are currently the common focus of climate science and policy. For example, the UNFCCC, signed and ratified by the U.S. in 1992, requires its signatories to ''develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol[33], using comparable methodologies * * * ''[34] To date, the focus of UNFCCC actions and discussions has been on the six greenhouse gases that are the same focus of these findings. As a Party to the UNFCCC, EPA annually submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Convention, which reports on national emissions of anthropogenic emissions of the well-mixed greenhouse gases. International discussions about a post-Kyoto agreement also focus on the well-mixed greenhouse gases.

As noted above, grouping of many substances with common attributes as a single pollutant is common practice under the CAA. Thus, doing so here is not novel. Indeed CAA section 302(g) defines air pollutant as ''any air pollutant agent or *combination of such agents,* * * * '' CAA § 302(g) (emphasis added). Thus, it is clear that the term ''air pollutant'' is not limited to individual chemical compounds. In determining that greenhouse gases are within the scope of this definition, the Supreme Court described section 302(g) as a ''sweeping'' and ''capacious'' definition that unambiguously included greenhouse gases, that are ''unquestionably 'agents' of air pollution.'' *Massachusetts* v. *EPA,* 549 U.S. at 528, 532, 529 n.26. Although the Court did not interpret the term ''combination of'' air pollution agents, there is no reason this phrase would be interpreted any less broadly. Congress used the term ''any'', and did not qualify the kind of combinations that the agency could define as a single air pollutant. Congress provided EPA broad discretion to determine appropriate combinations of compounds that should be treated as a singe air pollutant.[35]

For the same reasons discussed in Section IV.A above, at this time, only carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride share all of these common attributes and thus they are the only substances that the Administrator finds to meet the definition of ''well-mixed greenhouse gas'' at this time.[36] Also as noted above, if in the future other substances are shown to meet the same criteria they may be added to the definition of this single air pollutant.

The Administrator is aware that CAA section 202(a) source categories do not emit all of the substances meeting the definition of well-mixed greenhouse gases. But that does not change the fact that all of these greenhouse gases share the attributes that make grouping them as a single air pollutant reasonable. As discussed further below, the reasonableness of this grouping does not turn on the particular source category being evaluated in a contribution finding.

B. The Administrator's Finding Regarding Whether Emissions of the Air Pollutant From Section 202(a) Source Categories Cause or Contribute to the Air Pollution That May Be Reasonably Anticipated To Endanger Public Health and Welfare

The Administrator finds that emissions of the well-mixed greenhouse gases from new motor vehicles contribute to the air pollution that may reasonably be anticipated to endanger public health and welfare. This contribution finding is for all of the CAA section 202(a) source categories and the Administrator considered emissions from all of these source categories. The relevant mobile sources under CAA section 202 (a)(1) are ''any class or classes of new motor vehicles or new motor vehicle engines, * * *.'' CAA section 202(a)(1) (emphasis added). The new motor vehicles and new motor vehicle engines (hereinafter ''CAA section 202(a) source categories'') addressed are: Passenger cars, light-duty trucks, motorcycles, buses, and medium and heavy-duty trucks. Detailed combined greenhouse gas emissions data for CAA section 202(a) source categories are presented in Appendix B of the TSD.[37]

The Administrator reached her decision after reviewing emissions data on the contribution of CAA section 202(a) source categories relative to both global greenhouse gas emissions and U.S. greenhouse gas emissions. Given that CAA section 202(a) source categories are responsible for about 4 percent of total global greenhouse gas emissions, and for just over 23 percent of total U.S. greenhouse gas emissions, the Administrator finds that both of these comparisons, independently and together, support a finding that CAA section 202(a) source categories contribute to the air pollution that may be reasonably anticipated to endanger public health and welfare. The Administrator is not placing primary weight on either approach; rather she finds that both approaches clearly establish that emissions of the well-mixed greenhouse gases from section 202(a) source categories contribute to air pollution with may reasonably be anticipated to endanger public health and welfare. As the Supreme Court noted, ''[j]udged by any standard, U.S.

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[33] The Montreal Protocol covers ozone-depleting substances which may also share physical attributes of the six key greenhouse gases in this action, but they do not share other attributes such as being the focus of climate science and policy. See section * * *.

[34] UNFCCC Art. 4.1(b).

[35] Indeed, the greenhouse gases hydrofluorocarbons and perfluorocarbons each are already a combination of multiple compounds.

[36] The term ''well-mixed greenhouse gases'' is based on one of the shared attributes discussed above—these greenhouse gases are sufficiently long-lived in the atmosphere such that, once emitted, concentrations of each gas become well mixed throughout the entire global atmosphere. Defining the air pollutant to be the combination of these six well-mixed greenhouse gases is based in part on this attribute—after the gases are emitted, they are sufficiently long-lived in the atmosphere to become well mixed as part of the air pollution.

[37] For section 202(a) source categories, only the hydrofluorocarbon emissions related to passenger compartment cooling are included. Emissions from refrigeration units that may be attached to trucks are considered emissions from nonroad engines under CAA section 213.

motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts v. EPA,* 549 U.S. at 525.[38]

1. Administrator's Approach in Making This Finding

Section 202(a) of the CAA source categories consist of passenger cars, light-duty trucks, motorcycles, buses, and heavy- and medium-duty trucks. As noted in the Proposed Findings, in the past the requisite contribution findings have been proposed concurrently with proposing emission standards for the relevant mobile source category. Thus, prior contribution findings often focused on a subset of the CAA section 202(a) (or other section) source categories. This final cause or contribute finding, however, is for all of the CAA section 202(a) source categories. The Administrator is considering emissions from all of these source categories in the determination.

Section 202(a) source categories emit the following well-mixed greenhouse gases: carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. As the basis for the Administrator's determination, EPA analyzed historical data of emissions of the well-mixed greenhouse gases for motor vehicles and motor vehicle engines in the United States from 1990 to 2007.

The Proposed Findings discussed a number of possible ways of assessing cause or contribute and the point was made that no single approach is required by the statute or has been used exclusively in previous determinations under the CAA. The Administrator also discussed how, consistent with prior cause or contribute findings and the science, she is using emissions as a proxy for contributions to atmospheric concentrations. This approach is reasonable for the well-mixed greenhouse gases, because cumulative emissions are responsible for the cumulative change in the concentrations in the atmosphere. Similarly, annual emissions are a perfectly reasonable proxy for annual incremental changes in atmospheric concentrations.

In making a judgment about the contribution of emissions from CAA section 202(a) source categories, the Administrator focused on making a reasoned overall comparison of emissions from the CAA section 202(a) source categories to emissions from other sources of greenhouse gases. This allows a determination of how the CAA section 202(a) source categories compare to all of the other sources that together as a group make up the total emissions contributors to the air pollution problem. The relative importance of the CAA section 202(a) source categories is central to making the contribution determination. Both the magnitude of these emissions and the comparison of these emissions to other sources provide the basis to determine whether the CAA section 202(a) source categories may reasonably be judged as contributing to the air pollution problem.

In many cases EPA makes this kind of comparison of source categories by a simple percentage calculation that compares the emissions from the source category at issue to a larger total group of emissions. Depending on the circumstances, a larger percentage often means a greater relative impact from that source category compared to the other sources that make up the total of emissions, and vice versa. However, the actual numerical percentages may have little meaning when viewed in isolation. The context of the comparison is needed to ensure the information is useful in evaluating the relative impact of one source compared to others. For example, the number of sources involved and the distribution of emissions across all of the sources can make a significant difference when evaluating the results of a percentage calculation. In some cases a certain percentage might mean almost all other sources are larger or much larger than the source at issue, while in other circumstances the same percentage could mean that the source at issue is in fact one of the larger contributors to the total.

The Administrator therefore considered the totality of the circumstances in order to best understand the role played by CAA section 202(a) source categories. This is consistent with Congress' intention for EPA to consider the cumulative impact of all sources of pollution. In that context, the global nature of the air pollution problem and the breadth of countries and sources emitting greenhouse gases means that no single country and no single source category dominate or are even close to dominating on a global scale. For example, the United States as a country is the second largest emitter of greenhouse gases, and emits approximately 18 percent of the world's total greenhouse gases. The total emissions of greenhouse gases worldwide are from numerous sources and countries, with each country and each source category contributing a relatively small percentage of the total emissions. That means that the relative ranking of countries or sources is not at all obvious from the magnitude of the percentage by itself. A country or a source may be a large contributor, in comparison to other countries or sources, even though its percentage contribution may appear relatively small.

In this situation, addressing a global air pollution problem may call for many different sources and countries to address emissions even if none by itself dominates or comes close to dominating the global inventory. A somewhat analogous situation can be found in the ozone air pollution problem in the United States. Emissions of NOx and volatile organic compounds (VOCs) often come from numerous small sources, as well as certain large source categories. We have learned that successful ozone control strategies often need to take this into account, and address both the larger sources of NOx and VOCs as well as the many smaller sources, given the breadth of sources that as a group lead to the total inventory of VOCs and NOx.

The global aspects of the greenhouse gas air pollution problem amplify this kind of situation many times over, where no single country or source category dominates or comes close to dominating the global inventory of greenhouse gas emissions. These unique, global aspects of the climate change problem tend to support consideration of contribution at lower percentage levels of emissions than might otherwise be considered appropriate when addressing a more typical local or regional air pollution problem. In this situation it is quite reasonable to consider emissions from source categories that are more important in relation to other sources, even if their absolute contribution initially may appear to be small.

In addition, the Administrator is aware of the fact that the United States is the second largest emitter of well-mixed greenhouse gases in the world. As the United States evaluates how to address climate change, the Administrator will analyze the various sources of emissions and the source's share of U.S. emissions. Thus, when analyzing whether a source category that emits well-mixed greenhouse gases in the United States contributes to the global problem, it is appropriate for the Administrator to consider how that source category fits into the larger picture of U.S. emissions. This ranking process within the United States allows the importance of the source category to

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[38] Because the Administrator is defining the air pollutant as the combination of well-mixed greenhouse gases, she is not issuing a final contribution finding based on the alternative definition discussed in the proposed findings (*e.g.,* each greenhouse gas as an individual air pollutant).

be seen compared to other U.S. sources, informing the judgment of the importance of emissions from this source category in any overall national strategy to address greenhouse gas emissions.

It is in this broader context that EPA considered the contribution of CAA section 202(a) sources. This provides useful information in determining the importance that should be attached to the emissions from the CAA section 202(a) sources.

In reaching her determination, the Administrator used two simple and straightforward comparisons to assess cause or contribute for CAA section 202(a) source categories: (1) As a share of total current global aggregate emissions of the well-mixed greenhouse gases; and (2) as a share of total current U.S. aggregate emissions of the well-mixed greenhouse gases.

Total well-mixed greenhouse gas emissions from CAA section 202(a) source categories were compared to total global emissions of the well-mixed greenhouse gases. The total air pollution problem, as already discussed, is the elevated and climbing levels of the six greenhouse gas concentrations in the atmosphere, which are global in nature because these concentrations are globally well mixed (whether they are emitted from CAA section 202(a) source categories or any other source within or outside the United States). In addition, comparisons were also made to U.S. total well-mixed greenhouse gases emissions to appreciate how CAA section 202(a) source categories fit into the larger U.S. contribution to the global problem. It is typical for the Administrator to consider these kinds of comparisons of emissions of a pollutant in evaluating contribution to air pollution, such as the concentrations of that same pollutant in the atmosphere (*e.g.,* the Administrator analyzes $PM_{2.5}$ emissions to determine if a source category contributes to $PM_{2.5}$ air pollution). When viewed in the circumstances discussed above, both of these comparisons provide useful information in determining whether these source categories should be judged as contributing to the total air pollution problem.

a. Section 202(a) of the CAA—Share of Global Aggregate Emissions of the Well-Mixed Greenhouse Gases

Global emissions of well-mixed greenhouse gases have been increasing, and are projected to continue increasing unless the major emitters take action to reduce emissions. Total global emissions of well-mixed greenhouse gases in 2005 (the most recent year for which data for all countries and all greenhouse gases are available)[39] were 38,726 teragrams of CO_2-equivlant ($TgCO_2eq$.)[40] This represents an increase in global greenhouse gas emissions of about 26 percent since 1990 (excluding land use, land use change and forestry). In 2005, total U.S. emissions of well-mixed greenhouse gases were responsible for 18 percent of global emissions, ranking only behind China, which was responsible for 19 percent of global emissions of well-mixed greenhouse gases.

In 2005 emissions of the well-mixed greenhouse gas pollutant from CAA section 202(a) source categories represented 4.3 percent of total global well-mixed greenhouse gas emissions and 28 percent of global transport well-mixed greenhouse gas emissions (Table 1 of these Findings). If CAA section 202(a) source categories' emissions of well-mixed greenhouse gas were ranked against total well-mixed greenhouse gas emissions for entire countries, CAA section 202(a) source category emissions would rank behind only China, the United States as a whole, Russia, and India, and would rank ahead of Japan, Brazil, Germany and every other country in the world. Indeed, countries with lower emissions than the CAA section 202(a) source categories are members of the 17 ''major economies'' ''that meet to advance the exploration of concrete initiatives and joint ventures that increase the supply of clean energy while cutting greenhouse gas emissions.'' *See http://www.state.gov/g/oes/climate/mem/*. It would be anomalous, to say the least, to consider Japan and these other countries as major players in the global climate change community and an integral part of the solution, but not find that CAA section 202(a) source category emissions contribute to the global problem. Thus, the Administrator finds that emission of well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution of well-mixed greenhouse gases.

TABLE 1—COMPARISON TO GLOBAL GREENHOUSE GAS (GHG) EMISSIONS (TG CO_2E)

	2005	Sec 202(a) share (percent)
All U.S. GHG emissions	7,109	23.5
Global transport GHG emissions	5,968	28.0
All global GHG emissions	38,726	4.3

b. Section 202(a) of the CAA—Share of U.S. Aggregate Emissions of the Well-Mixed Greenhouse Gases

The Administrator considered compared total emissions of the well-mixed greenhouse gases from CAA section 202(a) source categories to total U.S. emissions of the well-mixed greenhouse gases as an indication of the role these sources play in the total U.S. contribution to the air pollution problem causing climate change.[41]

In 2007, U.S. well-mixed greenhouse gas emissions were 7,150 $TgCO_2eq$. The dominant gas emitted was carbon dioxide, mostly from fossil fuel combustion. Methane was the second largest well-mixed greenhouse gas, followed by N_2O, and the fluorinated gases (HFCs, PFCs, and SF_6). Electricity generation was the largest emitting sector (2,445 $TgCO_2eq$ or 34 percent of

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[39] The source of global greenhouse gas emissions data, against which comparisons are made, is the Climate Analysis Indicators Tool of the World Resources Institute (WRI) (2007). Note that for global comparisons, all emissions are from the year 2005, the most recent year for which data for all greenhouse gas emissions and all countries are available. WRI (2007) Climate Analysis Indicators Tool (CAIT). Available at *http://cait.wri.org.* Accessed August 5, 2009.

[40] One teragram (Tg) = 1 million metric tons. 1 metric ton = 1,000 kg = 1.102 short tons = 2,205 lbs. Long-lived greenhouse gases are compared and summed together on a CO_2 equivalent basis by multiplying each gas by its Global Warming Potential (GWPs), as estimated by IPCC. In accordance with UNFCCC reporting procedures, the U.S. quantifies greenhouse gas emissions using the 100-year time frame values for GWPs established in the IPCC Second Assessment Report.

[41] Greenhouse gas emissions data for the United States in this section have been updated since the Proposed Findings to reflect EPA's most up-to-date information, which includes data for the year 2007. The source of the U.S. greenhouse gas emissions data is the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007,* published in 2009 (hereinafter ''U.S. Inventory'').

total U.S. greenhouse gas emissions), followed by transportation (1,995 $TgCO_2eq$ or 28 percent) and industry (1,386 $TgCO_2eq$ or 19 percent). Emissions from the CAA section 202(a) source categories constitute the major part of the transportation sector. Land use, land use change, and forestry offset almost 15 percent of total U.S. emissions through net sequestration. Total U.S. well-mixed greenhouse gas emissions have increased by over 17 percent between 1990 and 2007. The electricity generation and transportation sectors have contributed the most to this increase.

In 2007 emissions of well-mixed greenhouse gases from CAA section 202(a) source categories collectively were the second largest emitter of well-mixed greenhouse gases within the United States (behind the electricity generating sector), emitting 1,663 $TgCO_2eq$ and representing 23 percent of total U.S. emissions of well-mixed greenhouse gases (Table 2 of these Findings). The Administrator is keenly aware that the United States is the second largest emitter of well-mixed greenhouse gases. Part of analyzing whether a sector within the United States contributes to the global problem is to see how those emissions fit into the contribution from the United States as a whole. This informs her judgment as to the importance of emissions from this source category in any overall national strategy to address greenhouse gas emissions. Thus, it is relevant that CAA section 202(a) source categories are the second largest emitter of well-mixed greenhouse gases in the country. This is part of the Administrator looking at the totality of the circumstances. Based on this the Administrator finds that emission of well-mixed greenhouse gases from CAA section 202(a) source categories contribute to the air pollution of well-mixed greenhouse gases.

TABLE 2—SECTORAL COMPARISON TO TOTAL U.S. GREENHOUSE GAS (GHG) EMISSIONS (TG CO_2E)

U.S. emissions	1990	1995	2000	2005	2006	2007
Section 202(a) GHG emissions	1231.9	1364.4	1568.1	1670.5	1665.7	1663.1
Share of U.S. (%)	20.2%	21.1%	22.4%	23.5%	23.6%	23.3%
Electricity Sector emissions	1859.1	1989.0	2329.3	2429.4	2375.5	2445.1
Share of U.S. (%)	30.5%	30.8%	33.2%	34.2%	33.7%	34.2%
Industrial Sector emissions	1496.0	1524.5	1467.5	1364.9	1388.4	1386.3
Share of U.S. (%)	24.5%	23.6%	20.9%	19.2%	19.7%	19.4%
Total U.S. GHG emissions	6098.7	6463.3	7008.2	7108.6	7051.1	7150.1

C. Response to Key Comments on the Administrator's Cause or Contribute Finding

EPA received numerous public comments regarding the Administrator's proposed cause or contribute finding. Below is a brief discussion of some of the key comments. Responses to comments on this issue are also contained in the Response to Comments document, Volume 10.

1. The Administrator Reasonably Defined the ''Air Pollutant'' for the Cause or Contribute Analysis

a. The Supreme Court Held that Greenhouse Gases Fit Within the Definition of ''Air Pollutant'' in the CAA

Several commenters reiterate arguments already rejected by the Supreme Court, arguing that greenhouse gases do not fit into the definition of ''air pollutant'' under the CAA. In particular, at least one commenter contends that EPA must show how greenhouse gases impact or materially change ''ambient air'' when defining air pollutant and making the endangerment finding. This commenter argues that because carbon dioxide is a naturally occurring and necessary element in the atmosphere, it cannot be considered to materially change air.

These and similar arguments were already rejected by the Supreme Court in *Massachusetts* v. *EPA*, 549 U.S. 497 (2007). Briefs before the Supreme Court also argued that carbon dioxide is an essential role for life on earth and therefore cannot be considered an air pollutant, and that the concentrations of greenhouse gases that are a potential problem are not in the ''ambient air'' that people breathe.

The Court rejected all of these and other arguments, noting that the statutory text forecloses these arguments. ''The Clean Air Act's sweeping definition of 'air pollutant' includes '*any* air pollution agent or combination of such agents, including *any* physical, chemical * * * substance or matter which is emitted into or otherwise enters the ambient air . * * *' § 7602(g) (emphasis added). On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through the repeated use of the word 'any.' Carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons are without a doubt 'physical [and] chemical * * * substance[s] which [are] emitted into * * * the ambient air.' The statute is unambiguous.''

547 U.S. at 529–30 (footnotes omitted); see also *id.* at 530, n26 (the distinction regarding ambient air, however, finds no support in the text of the statute, which uses the phrase ''the ambient air'' without distinguishing between atmospheric layer.). Thus, the question of whether greenhouse gases fit within the definition of air pollutant under the CAA has been decided by the Supreme Court and is not being revisited here.

b. The Definition of Air Pollutant May Include Substances Not Emitted by CAA Section 202(a) Sources

Many commenters argue that the definition of ''air pollutant''—here well-mixed greenhouse gases—cannot include PFCs and SF6 because they are not emitted by CAA section 202(a) motor vehicles and hence, cannot be part of any ''air pollutant'' emitted by such sources. They argue that by improperly defining ''air pollutant'' to include substances that are not present in motor vehicle emissions, the Agency has exceeded its statutory authority under CAA section 202(a). Commenters contend that past endangerment findings under CAA section 202(a) demonstrate EPA's consistent approach of defining ''air pollutant(s)'' in accordance with the CAA's clear direction, to include only those pollutants emitted from the relevant source category (citing Notice of Proposed Rulemaking for Heavy-Duty Engine and Vehicle Standards finding that ''emissions of NO_X, VOCs, SO_X, and PM from heavy-duty trucks can reasonably be anticipated to endanger the public health or welfare.'' (65 FR 35436, June 2, 2000). Commenters argue that EPA itself is inconsistent in the Proposed Findings, sometimes referring to ''air pollutant'' as the group of six greenhouse gases, and other times falling back on the four greenhouse gases emitted by motor vehicles.

EPA acknowledges that the Proposed Findings could have been clearer regarding the proposed definition of air pollutant, and how it was being applied to CAA section 202(a) sources, which emit only four of the six substances that meet the definition of well-mixed greenhouse gases. However, our interpretation does not exceed EPA's authority under CAA section 202(a). It is reasonable to define the air pollutant under CAA section 202(a) to include substances that have similar attributes (as discussed above), even if not all of the substances that meet that definition are emitted by motor vehicles. For example, as commenters note, EPA has heavy duty truck standards applicable to VOCs and PM, but it is highly unlikely that heavy duty trucks emit *every* substance that is included in the group defined as VOC or PM. *See* 40 CFR 51.100(s) (defining volatile organic compound (VOC) as ''any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions'', a list of exemptions are also included in the definition); 40 CFR 51.100(oo) (defining particulate matter (PM) as ''any airborne finely divided solid or liquid material with an aerodynamic diameter smaller than 100 micrometers'').

In this circumstance the number of substances included in the definition of well-mixed greenhouse gases is much smaller than other ''group'' air pollutants (*e.g.,* six greenhouse gases versus hundreds of VOCs), and CAA section 202(a) sources emit an easily discernible number of these six substances. However, this does not mean that the definition of the well-mixed greenhouse gases as the air pollutant is unreasonable. By defining well-mixed greenhouse gases as a single air pollutant comprised of six substances with common attributes, the Administrator is giving effect to these shared attributes and how they are relevant to the air pollution to which they contribute. The fact that these six substances share these common, relevant attributes is true regardless of the source category being evaluated for contribution. Grouping these six substances as one air pollutant is reasonable regardless of whether a contribution analysis is undertaken for CAA section 202(a) sources that emit one subset of the six substances (*e.g.*, carbon dioxide, CH_4, N_20 and HFCs, but not PFCs and SF_6), or for another category of sources that may emit another subset. For example, electronics manufacturers that may emit N_2O, PFCs, HFCs, SF_6 and other fluorinated compounds, but not carbon dioxide or CH_4 unless there is on-site fuel combustion. In other words, it is not necessarily the source category being evaluated for contribution that determines the reasonableness of defining a group air pollutant based on the shared attributes of the group.

Even if EPA agreed with commenters, and defined the air pollutant as the group of four compounds emitted by CAA section 202(a) sources, it would not change the result. The Administrator would make the same contribution finding as it would have no material effect on the emissions comparisons discussed above.

c. It Was Reasonable for the Administrator To Define the Single Air Pollutant as the Group of Substances With Common Attributes

Several commenters disagree with EPA's proposed definition of a single air pollutant composed of the six well-mixed greenhouse gases as a class. Commenters argue that the analogy to VOCs is misplaced because VOCs are all part of a defined group of chemicals, for which there are established quantification procedures, and for which there were extensive data showing that the group of compounds had demonstrated and quantifiable effects on ambient air and human health and welfare, and for which verifiable dispersion models existed. They contend this is in stark contrast to the entirely diverse set of organic and inorganic compounds EPA has lumped together for purposes of the Proposed Findings, and for which no model can accurately predict or quantify the actual impact or improvement resulting from controlling the compounds. Moreover, they argue that the gases EPA is proposing to list together as one pollutant are all generated by different processes and, if regulated, would require different types of controls; the four gases emitted by mobile sources can generally be limited only by using controls that are specific to each.

At least one commenter argues that EPA cannot combine greenhouse gases into one pollutant because their common attribute is not a ''physical, chemical, biological or radioactive property'' (quoting from CAA section 302(g)), but rather their effect or impacts on the environment. They say this differs from VOCs, which share the common attribute of volatility, or PM which shares the physical property of being particles.

As discussed above, the well-mixed greenhouse gases share physical attributes, as well as attributes based on sound policy considerations. The definition of ''air pollutant'' in CAA section 302(g) does not limit consideration of common attributes to those that are ''physical, chemical, biological or radioactive property'' as one commenter claims. Rather, the definition's use of the adjectives ''physical, chemical, biological or radioactive'' refer to the different types of substance or matter that is emitted. It is not a limitation on what characteristics the Administrator may consider when deciding how to group similar substances when defining a single air pollutant.

The common attributes that the Administrator considered when defining the well-mixed greenhouse gases are reasonable. While these six substances may originate from different processes, and require different control strategies, that does not detract from the fact that they are all long-lived, well-mixed in the atmosphere, directly emitted, of well-known radiative forcing, and generally grouped and considered together in climate change scientific and policy forums. Indeed, other group pollutants also originate from a variety of processes and a result may require different control technologies. For example, both a power plant and a dirt road can result in PM emissions, and the method to control such emissions at each source would be different. But these differences in origin or control do not undermine the reasonableness of considering PM as a single air pollutant. The fact that there are differences, as well as similarities, among the well-mixed greenhouse gases does not render the decision to group them together as one air pollutant unreasonable.

2. The Administrator's Cause or Contribute Analysis Was Reasonable

a. The Administrator Does Not Need To Find Significant Contribution, or Establish a Bright Line

Many commenters essentially argue that EPA must establish a bright line below which it would never find contribution regardless of the air pollutant, air pollution, and other factors before the Agency. For example, some commenters argue that EPA must provide some basis for determining de minimis amounts that fall below the threshold of ''contributing'' to the endangerment of public health and welfare under CAA section 202(a).

Commenters take issue with EPA's statement that it ''need not determine at this time the circumstances in which emissions would be trivial or de minimis and would not warrant a finding of contribution.'' Commenters argue that EPA cannot act arbitrarily by determining that a constituent contributing a certain percent to endangerment in one instance is de minimis and in another is contributing to endangerment of public health and welfare. They request that EPA revise the preamble language to make clear that the regulated community can rely on its past determinations with respect to ''contribution'' determinations to predict future agency action and argue that EPA should promulgate guidance on how it determines whether a contribution exceeds a de minimis level for purposes of CAA section 202(a) before finalizing the proposal.

The commenters that argue that the air pollution EPA must analyze to determine endangerment is limited to the air pollution resulting from new motor vehicles also argue that as a result, the contribution of emissions from new motor vehicles must be significant. They essentially contend that the endangerment and cause or contribute tests are inter-related and the universe of both tests is the same. In support of their argument, commenters argue that because the clause ''cause, or contribute to, air pollution'' is in plural form, it must be referring back to ''any class or classes of new motor vehicles or new motor vehicle engines,'' demonstrating that EPA must consider only the emissions from new motor vehicles which emit the air pollution which endangers.

Since the Administrator issued the Proposed Findings, the DC Circuit issued another opinion discussing the concept of contribution. See *Catawba County* v. *EPA*, 571 F.3d 20 (DC Cir. 2009). This decision, along with others, supports the Administrator's interpretation that the level of contribution under CAA section 202(a) does not need to be significant. The Administrator is not required to establish a bright line below which she would never find contribution under any circumstances. Finally, it is reasonable for the Administrator to apply a ''totality-of-the-circumstances test to implement a statute that confers broad discretionary authority, even if the test lacks a definite 'threshold' or 'clear line of demarcation to define an open-ended term.'' *Id.* at 39 (citations omitted).

In upholding EPA's $PM_{2.5}$ attainment and nonattainment designation decisions, the DC Circuit analyzed CAA section 107(d), which requires EPA to designate an area as nonattainment if it ''contributes to ambient air quality in a nearby area'' not attaining the national ambient air quality standards. *Id.* at 35. The court noted that it had previously held that the term ''contributes'' is ambiguous in the context of CAA language. *See EDF* v. *EPA*, 82 F.3d 451, 459 (DC Cir. 1996). ''[A]mbiguities in statutes within an agency's jurisdiction to administer are delegations of authority to the agency to fill the statutory gap in reasonable fashion.'' 571 F.3d at 35 (citing *Nat's Cable & Telecomms. Ass'c* v. *Brand X Internet Servs,* 545 U.S. 967, 980 (2005)).

The court then proceeded to consider and reject petitioners' argument that the verb ''contributes'' in CAA section 107(d) necessarily connotes a significant causal relationship. Specifically, the DC Circuit again noted that the term is ambiguous, leaving it to EPA to interpret in a reasonable manner. In the context of this discussion, the court noted that ''a contribution may simply exacerbate a problem rather than cause it * * * '' 571 F.3d at 39. This is consistent with the DC Circuit's decision in *Bluewater Network* v. *EPA,* 370 F.3d 1 (DC Cir. 2004), in which the court noted that the term contribute in CAA section 213(a)(3) ''[s]tanding alone, * * * has no inherent connotation as to the magnitude or importance of the relevant 'share' in the effect; certainly it does not incorporate any 'significance' requirement.'' 370 F.3d at 13. The court found that the bare ''contribute'' language invests the Administrator with discretion to exercise judgment regarding what constitutes a sufficient contribution for the purpose of making an endangerment finding. *Id.* at 14.

Finally, in *Catawba County,* the DC Circuit also rejected ''petitioners' argument that EPA violated the statute by failing to articulate a quantified amount of contribution that would trigger'' the regulatory action. 571 F.3d at 39. Although petitioners preferred that EPA establish a bright-line test, the court recognized that the statute did not require that EPA ''quantify a uniform amount of contribution.'' *Id.*

Given this context, it is entirely reasonable for the Administrator to interpret CAA section 202(a) to require some level of contribution that, while more than de minimis or trivial, does not rise to the level of significance. Moreover, the approach suggested by at least one commenter collapses the two prongs of the test by requiring that contribution must be significant because any climate change impacts upon which an endangerment determination is made result solely from the greenhouse gas emissions of motor vehicles. It essentially eliminates the ''contribute'' part of the ''cause or contribute'' portion of the test. This approach was clearly rejected by the en banc court in *Ethyl.* 541 F.2d at 29 (rejecting the argument that the emissions of the fuel additive to be regulated must ''in and of itself, *i.e.* considered in isolation, endanger[ ] public health.''); see also *Catawba County,* 571 F.3d at 39 (noting that even if the test required significant contribution it would be reasonable for EPA to find a county's addition of $PM_{2.5}$ is significant even though the problem would persist in its absence). It is the commenter, not EPA that is ignoring the statutory language. Whether or not the clause ''cause, or contribute to, air pollution'' refers back to ''any class or classes of new motor vehicles or new motor vehicle engines,'' or to ''emission of any air pollutant,'' the language of CAA section 202(a) clearly contemplates that emission of an air pollutant from any class or classes may merely contribute to, versus cause, the air pollution which endangers.

It is also reasonable for EPA to decline to establish a ''bright-line 'objective' test of contribution.'' 571 F.3d at 39. As noted in the Proposed Findings, when exercising her judgment, the Administrator not only considers the cumulative impact, but also looks at the totality of the circumstances (*e.g.,* the air pollutant, the air pollution, the nature of the endangerment, the type of source category, the number of sources in the source category, and the number and type of other source categories that may emit the air pollutant) when determining whether the emissions justify regulation under the CAA. *Id.* (It is reasonable for an agency to adopt a totality-of-the-circumstances test).

Even if EPA agreed that a level of significance was required to find contribution, for the reasons discussed above, EPA would find that the contribution from CAA section 202(a) source categories is significant. Their emissions are larger than the great majority of emitting countries, larger than several major emitting countries, and they constitute one of the largest parts of the U.S. emissions inventory.

b. The Unique Global Aspects of Climate Change Are an Appropriate Consideration in the Contribution Analysis

Some commenters disagree with statements in the Proposed Findings that the ''unique, global aspects of the climate change problem tend to support a finding that lower levels of emissions should be considered to contribute to the air pollution than might otherwise be appropriate when considering contribution to a local or regional air pollution problem.'' They argue there is no basis in the CAA or existing EPA policy for this position, and that it reveals an apparent effort to expand EPA's authority to the ''truly trivial or de minimis'' sources that are acknowledged to be outside the scope of regulation, in that it expands EPA's authority to regulate pollutants to address global effects.

Commenters also assert that contrary to EPA's position, lower contribution numbers are appropriate when looking at local pollution, like nonattainment concerns—in other words, in the context of a statutory provision like CAA section 213 specifically aimed at targeting small source categories to help nonattainment areas meet air quality standards. However, they conclude this policy is simply inapplicable in the context of global climate change.

As discussed above, the term ''contribute'' is ambiguous and subject to the Administrator's reasonable interpretation. It is entirely appropriate for the Administrator to look at the totality of the circumstances when making a finding of contribution. In this case, the Administrator believes that the global nature of the problem justifies looking at contribution in a way that takes account of these circumstances. More specifically, because climate change is a global problem that results from global greenhouse gas emissions, there are more sources emitting greenhouse gases (in terms both of absolute numbers of sources and types of sources) than EPA typically encounters when analyzing contribution towards a more localized air pollution problem. From a percentage perspective, there are no dominating sources and fewer sources that would even be considered to be close to dominating. The global problem is much more the result of numerous and varied sources each of which emit what might seem to be smaller percentage amounts when compared to the total. The Administrator's approach recognizes this reality, and focuses on evaluating the relative importance of the CAA section 202(a) source categories compared to other sources when viewed in this context.

This recognition of the unique totality of the circumstances before the Administrator now as compared to previous contribution decisions is entirely appropriate. It is not an attempt by the Administrator to regulate ''truly trivial or de minimis'' sources, or to regulate sources based on their global effects. The Administrator is determining whether greenhouse gas emissions from CAA section 202(a) sources contribute to an air pollution problem is endangering U.S. public health and welfare. As discussed in the Proposed Findings, no single greenhouse gas source category dominates on the global scale, and many (if not all) individual greenhouse gas source categories could appear small in comparison to the total, when, in fact, they could be very important contributors in terms of both absolute emissions or in comparison to other source categories, globally or within the United States. If the United States and the rest of the world are to combat the risks associated with global climate change, contributors must do their part even if their contributions to the global problem, measured in terms of percentage, are smaller than typically encountered when tackling solely regional or local environmental issues. The commenters' approach, if used globally, would effectively lead to a tragedy of the commons, whereby no country or source category would be accountable for contributing to the global problem of climate change, and nobody would take action as the problem persists and worsens. The Administrator's approach, on the contrary, avoids this kind of approach, and is a reasonable exercise of her discretion to determine contribution in the global context in which this issue arises.

Importantly, as discussed above, the contribution from CAA section 202(a) sources is anything but trivial or de minimis under any interpretation of contribution. See, *Massachusetts v. EPA,* 549 U.S. at 1457–58 (''Judged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming'').

c. The Administrator Reasonably Relied on Comparisons of Emissions From Existing CAA Section 202(a) Source Categories

i. It Was Reasonable To Use Existing Emissions From Existing CAA Section 202(a) Source Categories Instead of Projecting Future Emissions From New CAA Section 202(a) Source Categories

Many commenters argue that EPA improperly evaluated the emissions from the entire motor vehicle fleet, and it is required to limit its calculation to just emissions from new motor vehicles. Thus the emissions that EPA should consider in the cause or contribute determination is far less than the 4.3 percent of U.S. greenhouse gas emissions attributed to motor vehicles in the Proposed Findings, because this number includes both new and existing motor vehicles. One commenter calculated the emissions from new motor vehicles as being 1.8 percent of global emissions, assuming approximately one year of new motor vehicle production in the United States (11 million vehicles) in a total global count currently of approximately 600 million motor vehicles.

In the Proposed Findings, EPA determined the emissions from the entire fleet of motor vehicles in the United States for a certain calendar year. EPA explained that, consistent with its traditional practice, it used the recent motor vehicle emissions inventory for the entire fleet as a surrogate for estimates of emissions for just new motor vehicles and engines. This was appropriate because future projected emissions are uncertain and current emissions data are a reasonable proxy for near-term emissions.

In effect, EPA is using the inventory for the current fleet of motor vehicles as a reasonable surrogate for a projection of the inventory from new motor vehicles over the upcoming years. New motor vehicles are produced year in and year out, and over time the fleet changes over to a fleet composed of such vehicles. This occurs in a relatively short time frame, compared to the time period at issue for endangerment. Because new motor vehicles are produced each year, and continue to emit over their entire life, over a relatively short period of time the emission from the entire fleet is from vehicles produced after a certain date. In addition, the emissions from new motor vehicles are not limited to the emissions that occur only during the one year when they are new, but are emissions over the entire life of the vehicle.

In such cases, EPA has traditionally used the recent emissions from the entire current fleet of motor vehicles as a reasonable surrogate for such a projection instead of trying to project and model those emissions. While this introduces some limited degree of uncertainty, the difference between recent actual emissions from the fleet and projected future emissions from the fleet is not expected to differ in any way that would substantively change the decision made concerning cause or contribution. There is not a specific numerical bright line that must be achieved, and the numerical percentages are not treated and do not need to be treated as precise values. This approach provides a reasonable and clear indication of the relative magnitudes involved, and EPA does not believe that attempting to make future projections (for both vehicles and the emissions value they are compared to) would provide any greater degree of accuracy or precision in developing such a relative comparison.

ii. The Administrator Did Not Have To Use a Subset or Reduced Emissions Estimate From Existing CAA Section 202(a) Source Categories

Several commenters note that although EPA looks at emissions from all motor vehicles regulated under CAA section 202(a) in its contribution analysis, the Presidential announcement in May 2009 indicated that EPA was planning to regulate only a subset of 202(a) sources. Thus, they question whether the correct contribution analysis should look only at the emissions from that subset and not all CAA section 202(a) sources. Some commenters also argue that because emission standards will not eliminate all greenhouse gas emissions from motor vehicles, the comparison should compare the amount of greenhouse gas emissions ''reduced'' by those standards to the global greenhouse emissions. They also contend that the cost of the new standards will cause individual consumers, businesses, and other vehicle purchasers to hold on to their existing vehicles to a greater extent, thereby decreasing the amount of emissions reductions attributable to the standard and appropriately considered in the contribution analysis. Some commenters go further and contend that EPA also can only include that incremental reduction that the EPA regulations will achieve beyond any reductions resulting from CAFE standards that NHTSA will set.

Although the May announcement and September proposed rule involved only the light duty motor vehicle sector, the Administrator is making this finding for all classes of new motor vehicles under CAA section 202(a). Thus, although the announcement and proposed rule involve light duty vehicles, EPA is working to develop standards for the rest of the classes of new motor vehicles under CAA section 202(a). As the Supreme Court noted, EPA has ''significant latitude as to the manner, timing, content, and coordination of its regulations with those of other agencies. *Massachusetts* v. *EPA,* 549 U.S. at 533.

The argument that the Administrator can only look at that portion of emissions that will be reduced by any CAA section 202(a) standards, and even then only the reduction beyond those attributable to CAFE rules, finds no basis in the statutory language. The language in CAA section 202(a) requires that the Administrator set ''standards applicable to the emission of any air pollutant from [new motor vehicles], which in [her] judgment cause, or contribute to, air pollution which [endangers].'' It does not say set ''standards applicable to the emission of any air pollutant from [new motor vehicles], if in [her] judgment the emissions of that air pollutant as reduced by that standard cause, or contribute to, air pollution which [endangers].'' As discussed above, the decisions on cause or contribute and endangerment are separate and distinct from the decisions on what emissions standards to set under CAA section 202(a). The commenter's approach would improperly integrate these separate decisions. Indeed, because, as discussed above, the Administrator does not have to propose standards concurrent with the endangerment and cause or contribute findings, she would have to be prescient to know at the time of the contribution finding exactly the amount of the reduction that would be achieved by the standards to be set. As discussed above, for purposes of these findings we look at what would be the emissions from new motor vehicles if no action were taken. Current emissions from the existing CAA section 202(a) vehicle fleet are an appropriate estimate.

d. The Administrator Reasonably Compared CAA Section 202(a) Source Emissions to Both Global and Domestic Emissions of Well-Mixed Greenhouse Gases

EPA received many comments on the appropriate comparison(s) for the contribution analysis. Several commenters argue that in order to get around the ''problem'' of basing an endangerment finding upon a source category that contributes only 1.8 percent annually to global greenhouse gas emissions, EPA inappropriately also made comparisons to total U.S. greenhouse gas emissions. These commenters argue that a comparison of CAA section 202(a) source emissions to U.S. greenhouse gas emissions, versus global emissions, is arbitrary for purposes of the cause or contribute analysis, because it conflicts with the Administrator's definition of ''air pollution,'' as well as the nature of global warming. They note that throughout the Proposed Findings, the Administrator focuses on the global nature of greenhouse gas. Thus, they continue, while the percentage share of motor vehicle emissions at the U.S. level may be relevant for some purposes, it is irrelevant to a finding of whether these emissions contribute to the air pollution, which the Administrator has proposed to define on a global rather than a domestic basis. Commenters also accuse EPA of arbitrarily picking and choosing when it takes a global approach (*e.g.,* endangerment finding) and when it does not (*e.g.,* contribution findings).

The language of CAA section 202(a) is silent regarding how the Administrator is to make her contribution analysis. While it requires that the Administrator assess whether emission of an air pollutant contributes to air pollution which endangers, it does not limit *how* she may undertake that assessment. It surely is reasonable that the Administrator look at how CAA section 202(a) source category emissions compare to global emissions on an absolute basis, by themselves. But the United States as a nation is the second largest emitter of greenhouse gases. It is entirely appropriate for the Administrator to decide that part of understanding how a U.S. source category emitting greenhouse gases fits into the bigger picture of global climate change is to appreciate how that source category fits into the contribution from the United States as a whole, where the United States as a country is a major emitter of greenhouse gases. Knowing that CAA section 202(a) source categories are the second largest emitter of well-mixed greenhouse gases in the country is relevant to understanding what role they play in the global problem and hence whether they ''contribute'' to the global problem. Moreover, the Administrator is not ''picking and choosing'' when she applies a global or domestic approach in these Findings. Rather, she is looking at both of these emissions comparisons as appropriate under the applicable science, facts, and law.

e. The Amount of Well-Mixed Greenhouse Gas Emissions From CAA Section 202(a) Sources Reasonably Supports a Finding of Contribution

Many commenters argue that the ''cause or contribute'' prong of the Proposal's endangerment analysis fails to satisfy the applicable legal standard, which requires more than a minimal contribution to the ''air pollution reasonably anticipated to endanger public health or welfare.'' They contend that emissions representing approximately four percent of total global greenhouse gas emissions are a minimal contribution to global greenhouse gas concentrations.

EPA disagrees. As stated above, CAA section 202(a) source category total emissions of well-mixed greenhouse gases are higher than most countries in the world; countries that the U.S. and others believe play a major role in the global climate change problem. Moreover, the percent of global well-mixed greenhouse gas emissions that CAA section 202(a) source categories represent is higher than percentages that the EPA has found contribute to air pollution problems. *See Bluewater Network,* 370 F.3d at 15 (''For Fairbanks, this contribution was equivalent to 1.2 percent of the total daily CO inventory for 2001.'') As noted above, there is no bright line for assessing contribution, but as discussed in the Proposed Findings and above, when looking at a global problem like climate change, with many sources of emissions and no dominating sources from a global perspective, it is reasonable to consider that lower percentages contribute than one may consider when looking at a local or regional problem involving fewer sources of emissions. The Administrator agrees that ''[j]udged by any standard, U.S. motor-vehicle emissions make a meaningful contribution to greenhouse gas concentrations and hence, * * * to global warming.'' *Massachusetts v. EPA,* 549 U.S. at 525.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it raises novel policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to Office of Management and Budget (OMB) recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). These Findings do not impose an information collection request on any person.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this action on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Because these Findings do not impose any requirements, the Administrator certifies that this action will not have a significant economic impact on a substantial number of small entities. This action does not impose any requirements on small entities. The endangerment and cause or contribute findings do not in-and-of-themselves impose any new requirements but rather set forth the Administrator's determination on whether greenhouse gases in the atmosphere may reasonably be anticipated to endanger public health or welfare, and whether emissions of greenhouse gases from new motor vehicles and engines contribute to this air pollution. Accordingly, the action affords no opportunity for EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the Findings.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA.

This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This finding does not impose any requirements on industry or other entities.

E. Executive Order 13132: Federalism

This action does not have federalism implications. Because this action does not impose requirements on any entities, it will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). This action does not have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, nor does it impose any enforceable duties on any Indian tribes. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. Although the Administrator considered health and safety risks as part of these Findings, the Findings themselves do not impose a standard intended to mitigate those risks.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy because it does not impose any requirements.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. at 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629, Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that these Findings will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Although the Administrator considered climate change risks to minority or low-income populations as part of these Findings, this action does not impose a standard intended to mitigate those risks and does not impose requirements on any entities.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective January 14, 2010.

Dated: December 7, 2009.

Lisa P. Jackson,

Administrator.

[FR Doc. E9–29537 Filed 12–14–09; 8:45 am]

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Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements

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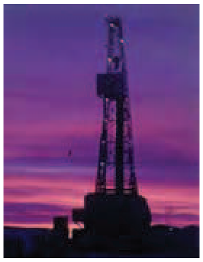


1.0 EXECUTIVE SUMMARY

Natural gas production in the Barnett Shale region of Texas has increased rapidly since 1999, and as of June 2008, over 7700 oil and gas wells had been installed and another 4700 wells were pending. Gas production in 2007 was approximately 923 Bcf from wells in 21 counties. Natural gas is a critical feedstock to many chemical production processes, and it has many environmental benefits over coal as a fuel for electricity generation, including lower emissions of sulfur, metal compounds, and carbon dioxide. Nevertheless, oil and gas production from the Barnett Shale area can impact local air quality and release greenhouse gases into the atmosphere. The objectives of this study were to develop an emissions inventory of air pollutants from oil and gas production in the Barnett Shale area, and to identify cost-effective emissions control options.

Emission sources from the oil and gas sector in the Barnett Shale area were divided into point sources, which included compressor engine exhausts and oil/condensate tanks, as well as fugitive and intermittent sources, which included production equipment fugitives, well drilling and fracing engines, well completions, gas processing, and transmission fugitives. The air pollutants considered in this inventory were smog-forming compounds (NO_x and VOC), greenhouse gases, and air toxic chemicals.

For 2009, emissions of smog-forming compounds from compressor engine exhausts and tanks were predicted to be approximately 96 tons per day (tpd) on an annual average, with peak summer emissions of 212 tpd. Emissions during the summer increase because of the effects of temperature on volatile organic compound emissions from storage tanks. Emissions of smog-forming compounds in 2009 from all oil and gas sources were estimated to be approximately 191 tpd on an annual average, with peak summer emissions of 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 165 tpd during the summer.

For comparison, 2009 emission inventories recently used by state and federal regulators estimated smog-forming emissions from all airports in the Dallas-Fort Worth metropolitan area to be 16 tpd. In addition, these same inventories had emission estimates for on-road motor vehicles (cars, trucks, etc.) in the 9-county Dallas-Fort Worth metropolitan area of 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties.

The emission rate of air toxic compounds (like benzene and formaldehyde) from Barnett Shale activities was predicted to be approximately 6 tpd on an annual average, and 17 tpd during peak summer days. The largest contributors to air toxic emissions were the condensate tanks, followed by the engine exhausts.

In addition, predicted 2009 emissions of greenhouse gases like carbon dioxide and methane were approximately 33,000 tons per day of CO_2 equivalent. This is roughly equivalent to the expected greenhouse gas impact from two 750 MW coal-fired power plants. The largest contributors to the Barnett Shale greenhouse gas impact were CO_2 emissions from compressor engine exhausts and fugitive CH_4 emissions from all source types.

Cost effective control strategies are readily available that can substantially reduce emissions, and in some cases, reduce costs for oil and gas operators. These options include:

- use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in electric motors as an alternative to internal-combustion engines to drive compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

2.0 BACKGROUND

2.1 Barnett Shale Natural Gas Production

The Barnett Shale is a geological formation that the Texas Railroad Commission (RRC) estimates to extend 5000 square miles in parts of at least 21 Texas counties. The hydrocarbon productive region of the Barnett Shale has been designated as the Newark East Field, and large scale development of the natural gas resources in the field began in the late 1990's. Figure 1 shows the rapid and continuing development of natural gas from the Barnett Shale over the last 10 years.(1)

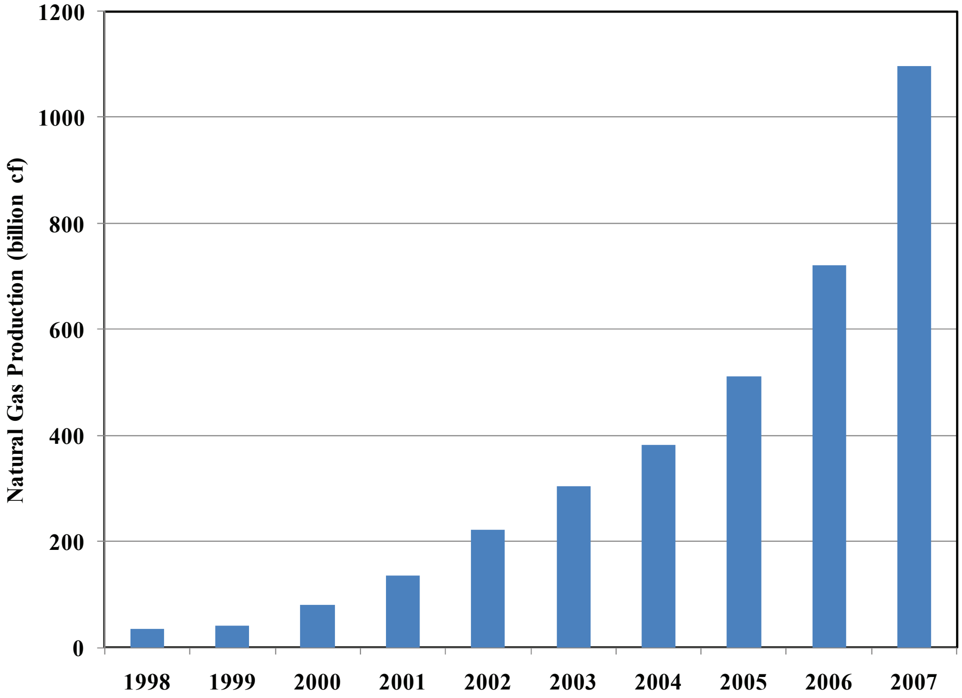


Figure 1. Barnett Shale Natural Gas Production, 1998-2007.

In addition to the recent development of the Barnett Shale, oil and gas production from other geologic formations and conventional sources in north central Texas existed before 1998 and continues to the present time. Production from the Barnett Shale is currently the dominant source of hydrocarbon production in the area from oil and gas activities in the area. Emission sources for all oil and gas activities are considered together in this report.

The issuance of new Barnett Shale area drilling permits has been following the upward trend of increasing natural gas production. The RRC issued 1112 well permits in 2004, 1629 in 2005, 2507 in 2006, 3657 in 2007, and they are on-track to issue over 4000 permits in 2008. The vast majority of the wells and permits are for natural gas production, but a small number of oil wells are also in operation or permitted in the area, and some oil wells co-produce casinghead gas. As of June 2008, over 7700 wells had been registered with the RRC, and the permit issuance rates are summarized in Table 1-1.(1) Annual oil, gas, condensate, and casinghead gas production rates for 21 counties in the Barnett Shale area are shown in Table 1-2.(1) The majority of Barnett Shale wells and well permits are located in six counties near the city of Fort Worth: Tarrant, Denton, Wise, Parker, Hood, and Johnson Counties. Figure 2 shows a RRC map of wells and well permits in the Barnett Shale.(2)

The top three gas producing counties in 2007 were Johnson, Tarrant and Wise, and the top three condensate producing counties were Wise, Denton, and Parker.

Nine (9) counties surrounding the cities of Fort Worth and Dallas have been designated by the U.S. EPA as the D-FW ozone nonattainment area (Tarrant, Denton, Parker, Johnson, Ellis, Collin, Dallas, Rockwall, and Kaufman). Four of these counties (Tarrant, Denton, Parker, and Johnson) have substantial oil or gas production. In this report, these 9 counties are referred to as the D-FW metropolitan area. The areas outside these 9-counties with significant Barnett Shale oil or gas production are generally more rural counties to the south, west, and northwest of the city of Fort Worth. The counties inside and outside the D-FW metropolitan area with oil and gas production are listed in Table 1-3.

Table 1-1. Barnett Shale Area Drilling Permits Issued, 2004-2008.(1)

year	new drilling permits
2004	1112
2005	1629
2006	2507
2007	3657
2008	4000+

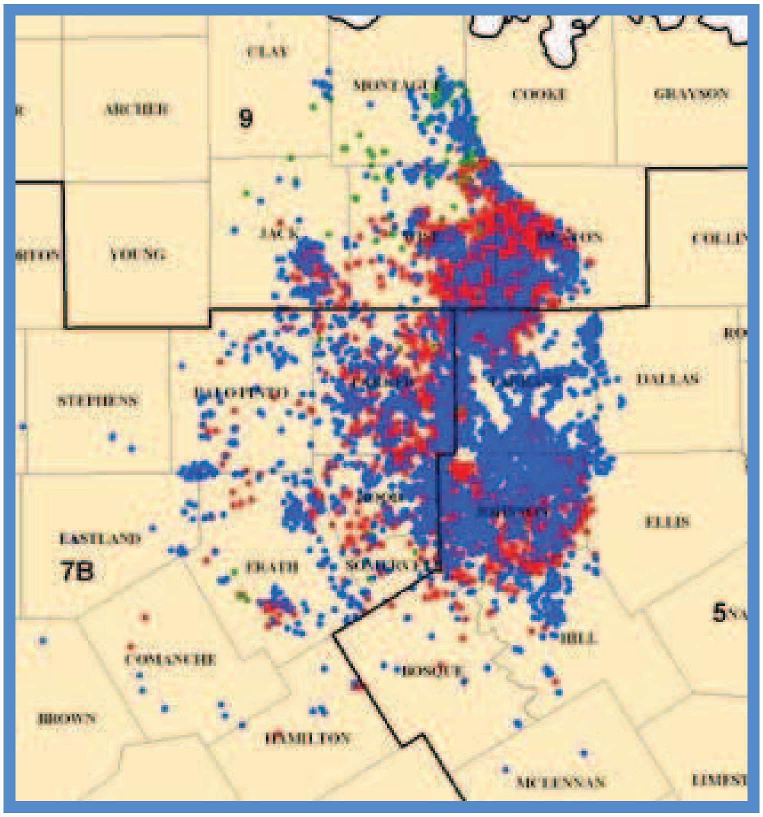
Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.(1)

County	Gas Production (MCF)	Condensate (BBL)	Casinghead Gas (MCF)	Oil Production (BBL)
Johnson	282,545,748	28,046	0	0
Tarrant	246,257,349	35,834	0	0
Wise	181,577,163	674,607	6,705,809	393,250
Denton	168,020,626	454,096	934,932	52,363
Parker	80,356,792	344,634	729,472	11,099
Hood	32,726,694	225,244	40,271	526
Jack	16,986,319	139,009	2,471,113	634,348
Palo Pinto	12,447,321	78,498	1,082,030	152,685
Stephens	11,149,910	56,183	3,244,894	2,276,637
Hill	7,191,823	148	0	0
Erath	4,930,753	11,437	65,425	5,073
Eastland	4,129,761	130,386	754,774	259,937
Somervell	4,018,269	6,317	0	0
Ellis	1,715,821	0	17,797	10
Comanche	560,733	1,584	52,546	7,055
Cooke	352,012	11,745	2,880,571	2,045,505
Montague	261,734	11,501	3,585,404	1,677,303
Clay	261,324	12,046	350,706	611,671
Hamilton	162,060	224	0	237
Bosque	135,116	59	0	0
Kaufman	0	0	3,002	61,963

Table 1-3. Relationship Between the D-FW Metropolitan Area and Counties Producing Oil/Gas in the Barnett Shale Area

D-FW 9-County Metropolitan Area	D-FW Metro. Counties Producing Barnett Area Oil/Gas	Rural Counties Producing Barnett Area Oil/Gas
Tarrant	Tarrant	Wise
Denton	Denton	Hood
Parker	Parker	Jack
Johnson	Johnson	Palo Pinto
Ellis	Ellis	Stephens
Collin		Hill
Dallas		Eastland
Rockwall		Somervell
Kaufman		Comanche
		Cooke
		Montague
		Clay
		Hamilton
		Bosque

Figure 2. Texas RRC Map of Well and Well Permit Locations in the Barnett Shale Area (red = gas wells, green = oil wells, blue = permits. RRC district 5, 7B, & 9 boundaries shown in black.)



2.2 Air Pollutants and Air Quality Regulatory Efforts

Oil and gas activities in the Barnett Shale area have the potential to emit a variety of air pollutants, including greenhouse gases, ozone and fine particle smog-forming compounds, and air toxic chemicals. The state of Texas has the highest greenhouse gas (GHG) emissions in the U.S., and future federal efforts to reduce national GHG emissions are likely to require emissions reductions from sources in the state. The three anthropogenic greenhouse gases of greatest concern, carbon dioxide, methane, and nitrous oxide, are emitted from oil and gas sources in the Barnett Shale area.

At present, air quality monitors in the Dallas-Fort Worth area show the area to be in compliance with the 1997 fine particulate matter ($PM_{2.5}$) air quality standard, which is 15 micrograms per cubic meter ($\mu g/m^3$) on an annual average basis. In 2006, the Clean Air Scientific Advisory Committee for EPA recommended tightening the standard to as low as 13 $\mu g/m^3$ to protect public health, but the EPA administrator kept the standard at the 1997 level. Fine particle air quality monitors in the Dallas-Fort Worth area have been above the 13 $\mu g/m^3$ level several times during the 2000-2007 time period, and tightening of the fine particle standard by future EPA administrators will focus regulatory attention at sources that emit fine particles or fine particle-forming compounds like NO_x and VOC gases.

2.3 Primary Emission Sources Involved in Barnett Shale Oil and Gas Production

There are a variety of activities that potentially create air emissions during oil and gas production in the Barnett Shale area. The primary emission sources in the Barnett Shale oil and gas sector include compressor engine exhausts, oil and condensate tank vents, production well fugitives, well drilling and hydraulic fracturing, well completions, natural gas processing, and transmission fugitives. Figure 3 shows a diagram of the major machinery and process units in the natural gas system.(3)

2.3.1 – Point Sources

i. Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines, and power compressors that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions. Most of the engines driving compressors in the Barnett Shale area are between 100 and 500 hp in size, but some large engines of 1000+ hp are also used.

ii. Condensate and Oil Tanks

Fluids that are brought to the surface at Barnett Shale natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids. Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. The hydrocarbon liquid is known as condensate.

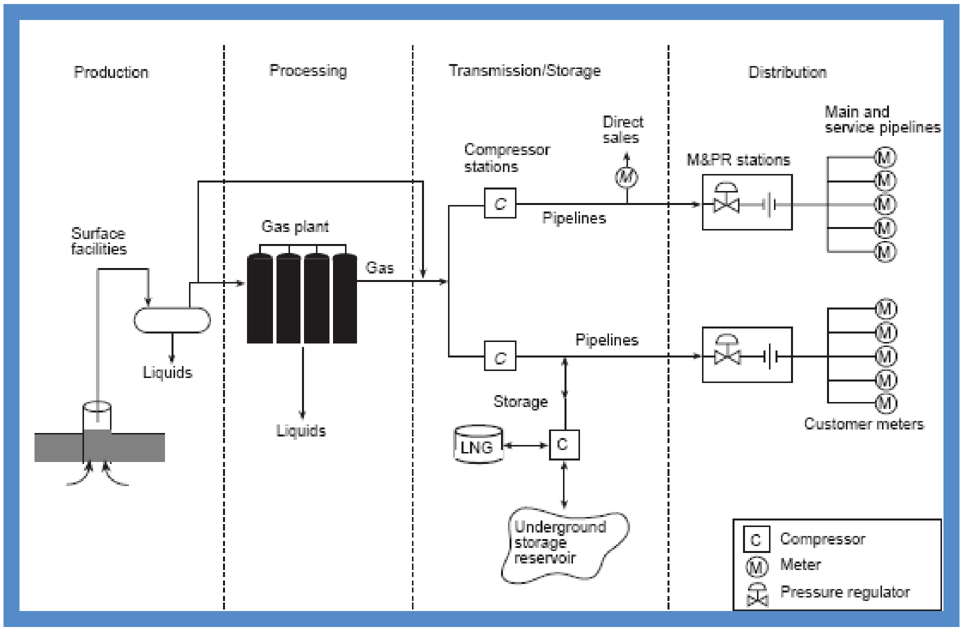


Figure 3. Major Units in The Natural Gas Industry From Wells to Customers. (3)

The condensate tanks at Barnett Shale wells are typically 10,000 to 20,000 gallons and hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. At oil wells, tanks are used to store crude oil on-site before the oil is transported to refiners. Like the condensate tanks, oil tanks can be sources of hydrocarbon vapor emissions to the atmosphere through tank vents.

2.3.2 – Fugitive and Intermittent Sources

i. Production Fugitive Emissions

Natural gas wells can contain a large number of individual components, including pumps, flanges, valves, gauges, pipe connectors, compressors, and other pieces. These components are generally intended to be tight, but leaks are not uncommon and some leaks can result in large emissions of hydrocarbons and methane to the atmosphere. The emissions from such leaks are called "fugitive" emissions. These fugitive emissions can be caused by routine wear, rust and corrosion, improper installation or maintenance, or overpressure of the gases or liquids in the piping. In addition to the unintended fugitive emissions, pneumatic valves which operate on pressurized natural gas leak small quantities of natural gas by design during normal operation. Natural gas wells, processing plants, and pipelines often contain large numbers of these kinds of pneumatic valves, and the accumulated emissions from all the valves in a system can be significant.

ii. Well Drilling, Hydraulic Fracturing, and Completions

Oil and gas drilling rigs require substantial power to from wellbores by driving drill bits to the depths of hydrocarbon deposits. In the Barnett Shale, this power is typically provided by transportable diesel engines, and operation of these engines generates exhaust from the burning of diesel fuel. After the wellbore is formed, additional power is needed to operate the pumps that move large quantities of water, sand/glass, or chemicals into the wellbore at high pressure to hydraulically fracture the shale to increase its surface area and release natural gas.

After the wellbore is formed and the shale fractured, an initial mixture of gas, hydrocarbon liquids, water, sand, or other materials comes to the surface. The standard hardware typically used at a gas well, including the piping, separator, and tanks, are not designed to handle this initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this "well completion" process, and direct the sand, water, and other liquids into ponds or tanks. After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting hardware at the well site. During well completions, the venting/flaring of the gas coming to the surface results in a loss of potential revenue and also in substantial methane and VOC emissions to the atmosphere.

iii. Natural Gas Processing

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. In addition to water, the glycol absorbent usually collects significant quantities of hydrocarbons, which can be emitted to the atmosphere when the glycol is regenerated with heat. The glycol dehydrators, pumps, and other machinery used in natural gas processing can release methane and hydrocarbons into the atmosphere, and emissions also originate from the numerous flanges, valves, and other fittings.

iv. Natural Gas Transmission Fugitives

Natural gas is transported from wells in mostly underground gathering lines that form networks that can eventually collect gas from hundreds or thousands of well locations. Gas is transported in pipeline networks from wells to processing plants, compressor stations, storage formations, and/or the interstate pipeline network for eventual delivery to customers. Leaks from pipeline networks, from microscopic holes, corrosion, welds and other connections, as well as from compressor intake and outlet seals, compressor rod packing, blow and purge operations, pipeline pigging, and from the large number of pneumatic devices on the pipeline network can result in large emissions of methane and hydrocarbons into the atmosphere and lost revenue for producers.

2.4 Objectives

Barnett Shale area oil and gas production can emit pollutants to the atmosphere which contribute to ozone and fine particulate matter smog, are known toxic chemicals, or contribute to climate change. The objectives of this study were to examine Barnett Shale oil and gas activities and : (1) estimate emissions of volatile organic compounds, nitrogen oxides, hazardous air pollutants, methane, carbon dioxide, and nitrous oxide; (2) evaluate the current state of regulatory controls and engineering techniques used to control emissions from the oil and gas sector in the Barnett Shale; (3) identify new approaches that can be taken to reduce emissions from Barnett Shale activities; and (4) estimate the emissions reductions and cost effectiveness of implementation of new emission reduction methods.

3.0 TECHNICAL APPROACH

3.1 Pollutants

Estimates were made of 2007 and 2009 emissions of smog forming, air toxic, and greenhouse gas compounds, including nitrogen oxides (NO_x), volatile organic compounds (VOCs), air toxics a.k.a. hazardous air pollutants (HAPs), methane (CH_4), nitrous oxide (N_2O), and carbon dioxide (CO_2). Volatile organic compounds are generally carbon and hydrogen-based chemicals that exist in the gas phase or can evaporate from liquids. VOCs can react in the atmosphere to form ozone and fine particulate matter. Methane and ethane are specifically excluded from the definition of VOC because they react slower than the other VOC compounds to produce ozone and fine particles, but they are ozone-causing compounds nonetheless. The HAPs analyzed in this report are a subset of the VOC compounds, and include those compounds that are known or believed to cause human health effects at low doses. An example of a HAP compound is benzene, which is an organic compound known to contribute to the development of cancer.

Emissions of the greenhouse gases CO_2, CH_4, and N_2O were determined individually, and then combined as carbon dioxide equivalent tons (CO_2e). In the combination, CH_4 tons were scaled by 21 and N_2O tons by 310 to account for the higher greenhouse gas potentials of these gases.(4)

Emissions in 2009 were estimated by examining recent trends in Barnett Shale hydrocarbon production, and where appropriate, extrapolating production out to 2009.

State regulatory programs are different for compressor engines inside the D-FW 9-county metropolitan area compared to outside. Engine emissions were determined separately for the two groups.

3.2 Hydrocarbon Production

Production rates in 2007 for oil, gas, casinghead gas, and condensate were obtained from the Texas Railroad Commission for each county in the Barnett Shale area.(5) The large amount of production from wells producing from the Barnett Shale, as well as the smaller amounts of production from conventional formations in the area were taken together. The area was analyzed in whole, as well as by counties inside and outside the D-FW 9-county metropolitan area. Production rates in 2009 were predicted by plotting production rates from 2000-2007 and fitting a 2nd-order polynomial to the production rates via the least-squares method and extrapolating out to 2009.

3.3 Compressor Engine Exhausts - Emission Factors and Emission Estimates

Emissions from the natural-gas fired compressor engines in the Barnett Shale were calculated for two types of engines: the generally large engines that had previously reported emissions into the TCEQ's Point Source Emissions Inventory (PSEI) prior to 2007 (a.k.a. PSEI Engines), and the generally smaller engines that had not previously reported emissions (a.k.a. non-PSEI Engines). Both these engine types are located in the D-FW 9-county metropolitan area (a.k.a. D-FW Metro Area), as well as in the rural counties outside the metropolitan area (a.k.a. Outside D-FW Metro Area). The four categories of engines are summarized in Figure 4 and the methods used to estimate emissions from the engines are described in the following sections.

Figure 4. Engine Categories.

Non-PSEI Engines in D-FW Metro Area	PSEI Engines in D-FW Metro Area	PSEI Engines Outside D-FW Metro Area	Non-PSEI Engines Outside D-FW Metro Area

i. Non-PSEI Engines in D-FW Metropolitan Area

Large natural gas compressor engines, located primarily at compressor stations and also some at well sites, have typically reported emissions to the Texas Commission on Environmental Quality (TCEQ) in annual Point Source Emissions Inventory (PSEI) reports. However, prior to 2007, many other stationary engines in the Barnett Shale area had not reported emissions to the PSEI and their contribution to regional air quality was unknown. In late 2007, the TCEQ conducted an engine survey for counties in the D-FW metropolitan area as part as efforts to amend the state clean air plan for ozone. Engine operators reported engine counts, engine sizes, NO_x emissions, and other data to TCEQ. Data summarized by TCEQ from the survey was used for this report to estimate emissions from natural gas engines in the Barnett Shale area that had previously not reported emissions into the annual PSEI.(6) Data obtained from TCEQ included total operating engine power in the metropolitan area, grouped by rich vs. lean burn engines, and also grouped by engines smaller than 50 hp, between 50 - 500 hp, and larger than 500 hp.

Regulations adopted by TCEQ and scheduled to take effect in early 2009 will limit NO_x emissions in the D-FW metropolitan area for engines larger than 50 horsepower.(7) Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. For this report, emissions in 2009 from the engines in the metropolitan area subject to the new rules were estimated assuming 97% compliance with the upcoming rules and a 3% noncompliance factor for engines continuing to emit at pre-2009 levels.

Emissions for 2007 were estimated using NO_x emission factors provided by operators to TCEQ in the 2007 survey.(6) Emissions of VOCs were determined using TCEQ-determined emission factors, and emissions of HAPs, CH_4, and CO_2 were determined using emission factors from EPA's AP-42 document.(8,9) In AP-42, EPA provides emission factors for HAP compounds that are created by incomplete fuel combustion. For this report only those factors which were judged by EPA to be of high quality, "A" or "B" ratings, were used to estimate emissions. Emission factors for the greenhouse gas N_2O were from an emissions inventory report issued by the American Petroleum Institute.(10)

Beginning in 2009, many engines subject to the new NO_x limits are expected to reduce their emissions with the installation of non-selective catalytic reduction units (NSCR), a.k.a. three-way catalysts. NSCR units are essentially modified versions of the "catalytic converters" that are standard equipment on every gasoline-engine passenger vehicle in the U.S.

A likely co-benefit of NSCR installation will be the simultaneous reduction of VOC, HAP, and CH_4 emissions. Emissions from engines expected to install NSCR units were determined using a 75% emissions reduction factor for VOC, HAPs, and CH_4. Conversely, NSCR units are known to increase N_2O emissions, and N_2O emissions were estimated using a 3.4x factor increase over uncontrolled emission factors.(10) Table 2 summarizes the emission factors used to calculate emissions from the compressor engines identified in the 2007 survey.

Table 2. Emission Factors for Engines Identified in the D-FW 2007 Engine Survey

Table 2-1. Emission Factors for 2007 Emissions

engine type	engine size	NO_x (g/hp-hr)[a]	VOC (g/hp-hr)[b]	HAPs (g/hp-hr)[c]	CH_4 (g/hp-hr)[d]	CO_2 (g-hp-hr)[e]	N_2O (g-hp-hr)[f]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	13.6	0.43	0.088	0.89	424	0.0077
rich	>500	0.9	0.43	0.088	0.89	424	0.0077
lean	<500	6.2	1.6	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

Table 2-2. Emission Factors for 2009 Emissions

engine type	engine size	NO_x (g/hp-hr)[i]	VOC (g/hp-hr)[j]	HAPs (g/hp-hr)[k]	CH_4 (g/hp-hr)[l]	CO_2 (g-hp-hr)[m]	N_2O (g-hp-hr)[n]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	0.5	0.11	0.022	0.22	424	0.026
rich	>500	0.5	0.11	0.022	0.22	424	0.026
lean[g]	<500	0.62	1.6	0.27	4.8	424	0.012
lean[h]	<500	0.5	1.6	0.27	4.8	424	0.012
lean[g]	>500	0.7	1.45	0.27	4.8	424	0.012
lean[h]	>500	0.5	1.45	0.27	4.8	424	0.012

notes:

a: email from TCEQ to SMU, August 1, 2008, summary of results from 2007 engine survey (reference 6).

b: email from TCEQ to SMU, August 6, 2008 (reference 8).

c: EPA, AP-42, quality A and B emission factors; rich engine HAPs = benzene, formaldehyde, toluene; lean engine HAPs = acetaldehyde, acrolein, xylene, benzene, formaldehyde, methanol, toluene, xylene (reference 9).

d: EPA, AP-42 (reference 9).

e: EPA, AP-42 (reference 9).

f: API Compendium Report (reference 10).

g: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

h: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

i: rich (<50) factor from email from TCEQ to SMU, August 1, 2008 (reference 6); rich (50-500), rich (>500), lean (<500, post-2007), lean (>500, pre-2007), and lean (>500, post-2007) from TCEQ regulatory limits (reference 7); lean (<500, pre-2007) estimated with 90% control.

j: rich (<50) from email from TCEQ to SMU (reference 8); rich (50-500) and rich (>500) estimated with 75% NSCR control VOC co-benefit; lean EFs from email from TCEQ to SMU (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.

k: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.

l: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.

m: EPA, AP-42 (reference 9).

n: API Compendium Report (reference 10); rich (50-500) and rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate.

Annual emissions from the engines identified in the 2007 survey were estimated using the pollutant-specific emission factors from Table 1 together with Equation 1,

$$M_{E,i} = 1.10E\text{-}06 * E_i * P_{cap} * F_{hl} \qquad (1)$$

where $M_{E,i}$ was the mass emission rate of pollutant *i* in tons per year, E_i was the emission factor for pollutant *i* in grams/hp-hr, P_{cap} is installed engine capacity in hp, and F_{hl} is a factor to adjust for annual hours of operation and typical load conditions.

Installed engine capacity in 2007 was determined for six type/size categories using TCEQ estimates from the 2007 engine survey - two engine types (rich vs. lean) and three engine size ranges (<50, 50-500, >500 hp) were included.(6) TCEQ estimates of the average engine sizes and the numbers of engines in each size category were used to calculate the installed engine capacity for each category, as shown in Table 3. The F_{hl} factor was used to account for typical hours of annual operation and average engine loads. A F_{hl} value of 0.5 was used for this study, based on 8000 hours per year of average engine operation (8000/8760 = 0.91) and operating engine loads of 55% of rated capacity, giving an overall hours-load factor of 0.91x 0.55 = 0.5.(11)

Table 3. Installed Engine Capacity in 2007 D-FW Engine Survey by Engine Type and Size

engine type	engine size (hp)	number of engines[q]	typical size[q] (hp)	installed capacity[r] (hp)
rich	<50	12	50	585
rich	50-500	724	140	101,000
rich	>500	200	1400	280,000
lean[o]	<500	14	185	2540
lean[p]	<500	13	185	2400
lean[o]	>500	103	1425	147,000
lean[p]	>500	103	1425	147,000

notes:

o: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

p: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

q: rich (<50) installed capacity based on HARC October 2006 H68 report which found that small rich burn engines comprise no more than 1% of engines in East Texas; rich (50-500) and rich (>500) installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6); lean burn installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6) along with RRC data suggesting that 50% of engines in 2009 will be subject to the post-June 2007 NOx rule.

r: installed capacity = number of engines x typical size

ii. PSEI Engines in D-FW Metropolitan Area

In addition to the engines identified in the 2007 TCEQ survey of the D-FW 9-county metropolitan area, many other stationary engines are also in use in the area. These include engines that had already been reporting annual emissions to TCEQ in the PSEI, which are principally large engines at compressor stations.(12)

Emissions of NO_x from large engines in the D-FW metropolitan area that were reporting to the TCEQ PSEI were obtained from the 2006 Annual PSEI, the most recent calendar year available.(12) Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production and compression needs from 2006-2009. For NO_x emissions in 2006 and 2007, an average emission factor of 0.9 g/hp-hr was obtained from TCEQ.(8) Emissions in 2009 were adjusted by accounting for the 0.5 g/hp-hr TCEQ regulatory limit scheduled to take effect in early 2009 for the D-FW metropolitan area.(7)

Unlike NO_x emission, emissions of VOC were not taken directly from the PSEI. Estimates of future VOC emissions required accounting for the effects that the new TCEQ engine NO_x limits will have on future VOC emissions. A compressor engine capacity production factor of 205 hp/(MMcf/day) was obtained from TCEQ that gives a ratio of installed horsepower capacity to the natural gas production. The 205 hp/(MMcf/day) factor was based on previous TCEQ studies of gas production and installed large engine capacity. The factor was used with 2006 gas production values to estimate installed PSEI engine capacities for each county in the Barnett Shale area.(8) Engine capacities were divided between rich burn engines smaller and larger than 500 hp, and lean burn engines. To estimate 2009 emissions, rich burn engines smaller than 500 hp are expected to have NSCR units by 2009 and get 75% VOC, HAP, and CH_4 control. Table 4 summarizes the VOC, HAP, and greenhouse gas emission factors used for the PSEI engines in the D-FW metropolitan area. Table 5 summarizes the estimates of installed engine capacity for each engine category.

Table 4. VOC, HAP, GHG Emission Factors for PSEI Engines in D-FW Metropolitan Area

Table 4-1. Emission Factors for 2007 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

Table 4-2. Emission Factors for 2009 Emissions

engine type	engine size	VOC EFs (g/hp-hr)[s]	HAPs EF (g/hp-hr)[t]	CH_4 EF (g/hp-hr)[u]	CO_2 EF (g/hp-hr)[v]	N_2O (g/hp-hr)[w]
rich	<500	0.11	0.022	0.22	424	0.026
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.47	0.27	4.8	424	0.012

notes:

s: email from TCEQ to SMU, August 6, 2008; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.47 to account for the effects of NSPS JJJJ rules on VOC emissions.

t: EPA, AP-42 (reference 9); 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

u: EPA, AP-42 (reference 9) ; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

v: EPA, AP-42 (reference 9).

w: API Compendium Report; 2007 rich (>500), and 2009 rich (>500) and 2009 rich (<500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 5. Installed Engine Capacity in 2007 for PSEI Engines Inside D-FW Metropolitan Area

engine type	engine size (hp)	installed capacity (%)[x]	installed capacity (hp)[y]
rich	<500	0.14	59,500
rich	>500	0.52	221,000
lean	all	0.34	144,000

notes:
x: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
y: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iii. PSEI Engines Outside D-FW Metropolitan Area

Emissions of NO_x from large engines outside the D-FW metropolitan area reporting to the TCEQ were obtained from the 2006 PSEI.(12) Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production from 2006-2009. Unlike engines inside the metropolitan area, the engines outside the metropolitan area are not subject to the new D-FW engine rules scheduled to take effect in 2009.

In addition to the D-FW engine rules, in 2007 the TCEQ passed the East Texas Combustion Rule that limited NO_x emissions from rich-burn natural gas engines larger than 240 hp in certain east Texas counties. Lean burn engines and engines smaller than 240 hp were exempted. The initial proposed rule would have applied to some counties in the Barnett Shale production area, including Cooke, Wise, Hood, Somervell, Bosque, and Hill, but in the final version of the rule these counties were removed from applicability, with the exception of Hill, which is still covered by the rule. Since gas production from Hill County is less than 3.5% of all the Barnett Shale area gas produced outside the D-FW metropolitan area, the East Texas Combustion Rule has limited impact to emissions from Barnett Shale area activity.

Emissions of VOC, HAPs, and greenhouse gases for large engines outside the D-FW metropolitan area were not obtained from the 2006 PSEI. A process similar to the one used to estimate emissions from large engines inside the metropolitan area was used, whereby the TCEQ compressor engine capacity production factor, 205 hp/(MMcf/day), was used along with actual 2007 production rates to estimate total installed engine capacity as well as installed capacity in each county for different engine categories. Pollutant-specific emission factors were applied to the capacity estimates for each category to estimate emissions. Table 6 summarizes the emission factors used to estimate emissions from engines in the PSEI outside the D-FW metropolitan area. The engine capacities used to estimate emissions are shown in Table 7.

Table 6. VOC, HAP, GHG Emission Factors for PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size	VOC (g/hp-hr)[z]	HAPs (g/hp-hr)[aa]	CH_4 (g/hp-hr)[aa]	CO_2 (g-hp-hr)[bb]	N_2O (g-hp-hr)[cc]
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.45	0.27	4.8	424	0.012

notes:
z: email from TCEQ to SMU, August 6, 2008; 75% control applied to rich (>500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.
aa: EPA, AP-42; 75% control applied to rich (>500) engines (reference 9).

bb. EPA, AP-42 (reference 9).
cc. API Compendium Report; rich (>500) engines estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 7. Installed Engine Capacity in 2007 for PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size (hp)	installed capacity (%)[dd]	installed capacity (hp)[ee]
rich	<500	0.14	17,000
rich	>500	0.52	62,000
lean	all	0.34	41,000

notes:
dd: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).
ee: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

iv. Non-PSEI Engines Outside the D-FW Metropolitan Area

The Point Source Emissions Inventory (PSEI) only contains emissions from a fraction of the stationary engines in the Barnett Shale area, principally the larger compressor engines with emissions above the PSEI reporting thresholds. The 2007 TCEQ engine survey of engines inside the D-FW metropolitan area demonstrated that the PSEI does not include a substantial fraction of total engine emissions. Most of the missing engines in the metropolitan area were units with emissions individually below the TCEQ reporting thresholds, but the combined emissions from large numbers of smaller engines can be substantial. The results of the 2007 survey indicated that there were approximately 680,000 hp of installed engine capacity in the D-FW metropolitan area not previously reporting to the PSEI.(6)

Natural gas and casinghead gas production from metropolitan counties in 2007 was approximately 1,000 Bcf . A "non-PSEI" compressor engine capacity production factor of 226 hp/(MMcf/day) was determined for the Barnett Shale area. This capacity factor accounts for all the small previously hidden engines that the 2007 survey showed come into use in oil and gas production activities in the area. This production factor was used along with 2007 gas production rates for the counties outside the D-FW metropolitan area to estimate non-PSEI engine emissions from these counties. The new production factor accounts for the fact that counties outside the metro area likely contain previously unreported engine capacity in the same proportion to the unreported engine capacity that was identified during the 2007 engine survey inside the metro area. Without a detailed engine survey in the rural counties of the same scope as the 2007 survey performed within the D-FW metropolitan counties, use of the non-PSEI production factor provides a way to estimate emissions from engines not yet in state or federal inventories. The capacity of non-PSEI reporting engines in the rural counties of the Barnett Shale was determined by this method to be 132,000 hp. Emission factors used to estimate emissions from these engines, and the breakdown of total installed engine capacity into engine type and size categories, are shown in Tables 8 and 9.

Table 8. Emission Factors for Non-PSEI Engines Outside D-FW Metropolitan Area

engine type	engine size	NO_x (g/hp-hr)[ff]	VOC (g/hp-hr)[gg]	HAPs (g/hp-hr)[hh]	CH_4 (g/hp-hr)[hh]	CO_2 (g-hp-hr)[ii]	N_2O (g-hp-hr)[jj]
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	10.3	0.43	0.088	0.89	424	0.0077
rich	>500	0.89	0.11	0.022	0.22	424	0.026
lean	<500	5.2	1.45	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

notes:

ff: email from TCEQ to SMU, August 1, 2008 (reference 6). Rich burn engines 50-500 hp NOx emission factor adjusted from 13.6 to 10.3 to account for the effects of NSPS JJJJ rules on NOx emissions and the effect of the TCEQ East Texas Combustion Rule on Hill County production. Rich burn engines >500 adjusted from 0.9 to 0.89 to account for the effect of the TCEQ East Texas Combustion Rule on Hill County production. Lean burn <500 hp engine post-2007 emission factor adjusted from 6.2 to 5.15 to account for the effects of NSPS JJJJ rules on NOx emissions.

gg: email from TCEQ to SMU, August 6, 2008; rich (>500) based on 75% control (reference 8). Small lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.

hh: EPA, AP-42; rich (>500) based on 75% control (reference 9).

ii: EPA, AP-42 (reference 9).

jj: API Compendium Report; rich (>500) estimated with 3.4x N_2O emissions increase over uncontrolled rate (reference 10).

Table 9. Installed Engine Capacity for Non-PSEI Engines Outside Metropolitan Area by Engine Type/Size

engine type	engine size (hp)	installed capacity (%)	installed capacity (hp)
rich	<50	0.01	110
rich	50-500	15	20,000
rich	>500	41	55,000
lean	<500	0.73	970
lean	>500	43	57,000

3.2 Condensate and Oil Tanks - Emission Factors and Emission Estimates

Condensate and oil tanks can be significant emitters of VOC, methane, and HAPs. A report was published in 2006 by URS Corporation which presented the results of a large investigation of emissions from condensate and oil tanks in Texas.(14) Tanks were sampled from 33 locations across East Texas, including locations in the Barnett Shale area. Condensate tanks in the Barnett Shale were sampled in Denton and Parker Counties, and oil tanks were sampled in Montague County. The results from the URS investigation were used in this study to calculate Barnett Shale-specific emission factors for VOC, CH_4, HAPs, and CO_2, instead of using a more general Texas-wide emission factor. The URS study was conducted during daylight hours in July 2006, when temperatures in North Texas are significantly above the annual average. Therefore, the results of the URS investigation were used to calculate "Peak Summer" emissions. The HAPs identified in the URS study included n-hexane, benzene, trimethylpentane, toluene, ethylbenzene, and xylene. The emission factors used to calculate peak summer emissions from Barnett

Shale condensate and oil tanks are shown in Table 10-1. Figure 5 shows a condensate tank battery from the 2006 URS study report.

Figure 5. Example Storage Tank Battery (left), Separators (right), and Piping.(14)

Computer modeling data were provided during personal communications with a Barnett Shale gas producer who estimated VOC, CH_4, HAPs, and CO_2 emissions from a number of their condensate tanks.(15) The tanks were modeled with ambient temperatures of 60 F, which the producer used to represent annual hourly mean temperatures in the D-FW area. These modeling results were used in this report to predict annual average condensate tank emission factors for the Barnett Shale area. The annual average emission factors are shown in Table 10-2.

Table 10. Condensate and Oil Tank Emission Factors for the Barnett Shale.

Table 10-1. Peak Summer Emission Factors.(14)

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	48	3.7	5.6	0.87
oil	6.1	0.25	0.84	2.7

Table 10-2. Annual Average Emission Factors.(15)

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH_4 (lbs/bbl)	CO_2 (lbs/bbl)
condensate	10	0.20	1.7	0.23
oil	1.3	0.013	0.26	0.70

Emissions for 2007 were calculated for each county in the Barnett Shale area, using condensate and oil production rates from the RRC.(5) Emissions for 2009 were estimated with the extrapolated 2000-2007 production rates for the year 2009. Emissions were calculated with Equation 2,

$$M_{T,i} = E_i * P_c * C / 2000 \qquad (2)$$

where $M_{T,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/bbl, P_c was the production rate of condensate or oil, and C was a factor to account for the reduction in emissions due to vapor-emissions controls on some tanks. For this report, the use of vapor-emissions controls on some tanks was estimated to provide a 25% reduction in overall area-wide emissions.

3.3 Production Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from production wells vary from well to well depending on many factors, including the tightness of casing heads and fittings, the age and condition of well components, and the numbers of flanges, valves, pneumatic devices, or other components per well. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.(15) Fugitive emissions of natural gas from the entire natural gas network were estimated to be 1.4% of gross production. Production fugitives, excluding emissions from condensate tanks (which are covered in another section of this report), were estimated by the GRI/EPA study to be approximately 20% of total fugitives, or 0.28% of gross production.

Production fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.28% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Volume emissions were converted to mass emissions with a density of 0.0483 lb/scf. Multiple Barnett Shale gas producers provided gas composition, heat content data, and area-wide maps of gas composition. The area-wide maps of gas composition were used to estimate gas composition for each producing county. These county-level data were weighted by the fraction of total area production that originated from each county to calculate area-wide emission factors. Table 11 presents the production fugitives emission factors.

Table 11. Production Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
11	0.26	99	1.9

Emissions were calculated with Equation 3,

$$M_{F,i} = E_i * P_g / 2000 \qquad (3)$$

where $M_{F,i}$ was the mass emission rate of pollutant *i* in tons per year, E_i was the emission factor for pollutant *i* in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. The area-wide unprocessed natural gas composition based on data from gas producers was 74% CH_4, 8.2% VOC, 1.4% CO_2, and 0.20% HAPs, on a mass % basis. HAPs in unprocessed natural gas can include low levels of n-hexane, benzene, or other compounds.

3.4 Well Drilling, Hydraulic Fracturing Pump Engines, and Well Completions - Emission Factors and Emission Estimates

Emissions from the diesel engines used to operate well drilling rigs and from the diesel engines that power the hydraulic fracturing pumps were estimated based on discussions with gas producers and other published data. Well drilling engine emissions were based on 25 days of engine operation for a typical well, with 1000 hp of engine capacity, a load factor of 50%, and operation for 12 hours per day. Hydraulic fracturing engine emissions were based on 4.5 days of operation for a typical well, with 1000 hp of capacity, a load factor of 50%, and operation for 12 hours per day. Some well sites in the D-FW are being drilled with electric-powered rigs, with electricity provided off the electrical grid. Engines emission estimates in this report were reduced by 25% to account for the number of wells being drilled without diesel-engine power.

In addition to emissions from drilling and fracing engines, previous studies have examined emissions of natural gas during well completions. These studies include one by the Williams gas company, which estimated that a typical well completion could vent 24,000 Mcf of natural gas.(18) A report by the EPA Natural Gas Star program estimated that 3000 Mcf could be produced from typical well completions.(19) A report by ENVIRON published in 2006 describes emission factors used in Wyoming and Colorado to estimate emissions from well completions, which were equivalent to 1000 to 5000 Mcf natural gas/well.(20) Another report published in the June 2005 issue of the Journal of Petroleum Technology estimated that well completion operations could produce 7,000 Mcf. (21) Unless companies bring special equipment to the well site to capture the natural gas and liquids that are produced during well completions, these gases will be vented to the atmosphere or flared.

Discussions with Barnett Shale gas producers that are currently employing “green completion” methods to capture natural gas and reduce emissions during well completions suggests that typical well completions in the Barnett Shale area can release approximately 5000 Mcf of natural gas/well. This value, which is very close to the median value obtained from previous studies (References 18-21), was used to estimate well completion emissions in this report.

The number of completed gas wells reporting to the RRC was plotted for the Feb. 2004 – Feb. 2008 time period.(22) A least-squares regression line was fit to the data, and the slope of the line provides the approximate number of new completions every year. A value of 1042 completions/year was relatively steady throughout the 2004-2008 time period (linear $R^2 = 0.9915$). Emissions in 2007 and 2009 from well completions were estimated using 1000 new well completions/year for each year. Emission estimates were prepared for the entire Barnett Shale area, as well as inside and outside the D-FW metropolitan area. The data from 2004-2008 show that 71 percent of new wells are being installed in the D-FW metropolitan area, 29 percent of new wells are outside the metropolitan area, and the rate of new completions has been steady since 2004. Emissions of VOC, HAPs, CH_4, and CO_2 were estimated using the same natural gas composition used for production fugitive emissions.

Some gas producers are using green completion techniques to reduce emissions, while others destroy natural gas produced during well completions by flaring. To account for the use of green completions and control by flaring, natural gas emission estimates during well completions were reduced by 25% in this report.

3.5 Processing Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from natural gas processing will vary from processing plant to processing plant, depending on the age of the plants, whether they are subject to federal rules such as the NSPS Subpart KKK requirements, the chemical composition of the gas being processed, the processing capacity of the plants, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.(15) Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Processing fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 9.7% of total fugitives, or 0.14% of gross production.

Processing fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.14% of the portion of gas production that is processed, estimated as 519 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were estimated with an area-wide natural gas composition, excluding the gas from areas of the Barnett Shale that does not require any processing. Volume emissions were converted to mass emissions with a natural gas density of 0.0514 lb/scf. Table 12 presents the processing fugitives emission factors.

Table 12. Processing Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
14	0.3	45	1.0

Processing fugitive emissions were calculated with Equation 4,

$$M_{P,i} = E_i * P_g / 2000 \qquad (4)$$

where $M_{P,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas. The composition of the natural gas produced in the Barnett Shale that is processed was estimated to be 65% CH_4, 1.5% CO_2, 20% VOC, and 0.48% HAPs, on a mass % basis. Not all natural gas from the Barnett Shale area requires processing.

3.6 Transmission Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from the transmission of natural gas will vary depending on the pressure of pipelines, the integrity of the piping, fittings, and valves, the chemical composition of the gas being transported, the tightness of compressor seals and rod packing, the frequency of blow down events, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.(15) Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Transmission fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 35% of total fugitive emissions, or 0.49% of gross production. Transmission includes the movement of natural gas from the wells to processing plants, and the processing plants to compressor stations. It does not include flow past the primary metering and pressure regulating (M&PR) stations and final distribution lines to customers. Final distribution of gas produced in the Barnett Shale can happen anywhere in the North American natural gas distribution system, and fugitive emissions from these lines are beyond the scope of this report.

Transmission fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.49% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH_4, and CO_2 were developed considering that a significant portion of the gas moving through the network does not require processing, while the portion of the gas with higher molecular weight compounds will go through processing. In addition, all gas will have a dry (high methane) composition after processing as it moves to compressor stations and then on to customers. Overall area-wide transmission fugitive emissions were calculated with a gas composition of 76% CH_4, 5.1% VOC, 1.4% CO_2, and 0.12% HAPs, by mass %. Table 13 presents the transmission fugitives emission factors.

Table 13. Transmission Fugitives Emission Factors for the Barnett Shale.

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH_4 (lbs/MMcf)	CO_2 (lbs/MMcf)
12	0.28	175	3.3

Transmission fugitive emissions were calculated with Equation 5,

$$M_{tr,i} = E_i * P_g / 2000 \tag{5}$$

where $M_{tr,i}$ was the mass emission rate of pollutant i in tons per year, E_i was the emission factor for pollutant i in lbs/MMcf, and P_g was the production rate of natural and casinghead gas.

4.0 RESULTS

4.1 Point Sources

i. Compressor Engine Exhausts

Emissions from compressor engines in the Barnett Shale area are summarized in Tables 14 and 15. Results indicate that engines are significant sources of ozone and particulate matter precursors (NO_x and VOC), with 2007 emissions of 66 tpd. Emissions of NO_x are expected to fall 50% from 32 to 16 tpd for engines in the Dallas-Fort Worth metropolitan area because of regulations scheduled to take effect in 2009 and the installation of NSCR units on many engines. Large reductions are unlikely because of the growth in natural gas production. For engines outside the D-FW metropolitan area counties, NO_x emissions will rise from 19 tpd to 30 tpd because of the projected growth in natural gas production and the fact that engines in these counties are not subject to the same regulations as those inside the metropolitan area.

Emissions of volatile organic compounds are expected to increase from 15 to 21 tpd from 2007 to 2009, because of increasing natural gas production. The 2009 engine regulations for the metropolitan area counties do have the effect of reducing VOC emissions from some engines, but growth in production compensates for the reductions and VOC emissions from engines as a whole increase.

HAP emissions, which include toxic compounds such as formaldehyde and benzene, are expected to increase from 2.7 to 3.6 tpd from 2007 to 2009.

Greenhouse gas emissions from compressor engines are shown in Table 15. Emissions in 2007 as carbon dioxide equivalent tons were approximately 8900 tpd, and emissions are estimated to increase to nearly 14,000 tpd by 2009. Carbon dioxide contributed the most to the greenhouse gas emissions, accounting for approximately 90% of the CO_2 equivalent tons. The methane contribution to greenhouse gases was smaller for the engine exhausts than for the other sources reviewed in this report.

Table 14. Emissions from Compressor Engine Exhausts.

	2007					2009				
	Pollutant (tpd)					Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Engines	32	13	2.2	35	7261	16	16	2.9	49	11294
Outside Metro Engines	19	2.5	0.45	7.4	1649	30	3.8	0.70	12	2583
Engines Total	**51**	**15**	**2.7**	**43**	**8910**	**46**	**19**	**3.6**	**61**	**13877**

Table 15. Greenhouse Gas Emissions Details.

	2007				2009			
	Pollutant (tpd)				Pollutant (tpd)			
	CO2	CH4	N2O	CO2e	CO2	CH4	N2O	CO2e
D-FW Metro Engines	6455	35	0.20	7261	10112	49	0.28	11294
Outside Metro Engines	1475	7.4	0.062	1649	2310	12	0.10	2583
Engines Total	**7930**	**43**	**0.26**	**8910**	**12422**	**61**	**0.38**	**13877**

ii. Oil and Condensate Tanks

Emissions from condensate and oil tanks are shown in Tables 16-1 and 16-2. Annual average emissions are shown in Table 16-1, and peak summer emissions are shown in Table 16-2.

On an annual average, emissions of VOCs from the tanks were 19 tpd in 2007, and emissions will increase to 30 tpd in 2009. Because of the effects of temperature on hydrocarbon liquid vapor pressures, peak summer emissions of VOC were 93 tpd in 2007, and summer emissions will increase to 146 tpd in 2009.

Substantial HAP emissions during the summer were determined for the tanks, with 2007 emissions of 7.2 tpd and 2009 emissions of 11 tpd. Greenhouse gas emissions from the tanks are almost entirely from CH_4, with a small contribution from CO_2. Annual average greenhouse gas emissions were 95 tpd in 2007, and will increase to 149 tpd in 2009.

Table 16. Emissions from Condensate and Oil Tanks.

Table 16-1. Annual Average Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	8.9	0.18	2.1	44	14	0.28	3.2	69
Outside Metro Tanks	10	0.21	2.4	51	16	0.32	3.8	80
Tanks Total	**19**	**0.39**	**4.5**	**95**	**30**	**0.60**	**7.0**	**149**

Table 16-2. Peak Summer Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Tanks	43	3.3	6.7	142	67	5.2	10	222
Outside Metro Tanks	50	3.8	7.8	166	79	6.0	12	261
Tanks Total	**93**	**7.2**	**15**	**308**	**146**	**11**	**23**	**483**

4.2 Fugitive and Intermittent Sources

i. Production Fugitives

Emissions from fugitive sources at Barnett Shale production sites are shown in Table 17. Production fugitives are significant sources of VOC emissions, with VOC emissions expected to grow from 2007 to 2009 from 17 to 26 tpd. Production fugitives are also very large sources of methane emissions, leading to large CO_2 equivalent greenhouse gas emissions. Greenhouse gas emissions were 3100 tpd in 2007 and will be 4900 tpd in 2009.

Table 17. Emissions from Production Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Production Fugitives	11	0.27	102	2147	18	0.43	160	3363
Outside Metro Production Fugitives	5.2	0.12	46	971	8.1	0.19	72	1521
Production Fugitives Total	**17**	**0.40**	**148**	**3118**	**26**	**0.62**	**232**	**4884**

ii. Well Drilling, Hydraulic Fracturing, and Well Completions

Emissions from well drilling engines, hydraulic fracturing pump engines, and well completions are shown in Table 18. These activities are significant sources of the ozone and fine particulate precursors, as well as very large sources of greenhouse gases, mostly from methane venting during well completions. Greenhouse gas emissions are estimated to be greater than 4000 CO_2 equivalent tons per year. Based on 2000-2007 drilling trends, approximately 71% of the well drilling, fracing, and completion emissions will be coming from counties in the D-FW metropolitan area, with the remaining 29% coming from counties outside the metropolitan area.

Table 18. Emissions from Well Drilling, Hydraulic Fracturing, and Well Completions.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Well Drilling and Well Completion	3.9	15	0.35	130	2883	3.9	15	0.35	130	2883
Outside Metro Well Drilling and Well Completions	1.6	6.1	0.14	53	1178	1.6	6.1	0.14	53	1178
Well Drilling and Completions Emissions Total	**5.5**	**21**	**0.49**	**183**	**4061**	**5.5**	**21**	**0.49**	**183**	**4061**

iii. Natural Gas Processing

Processing of Barnett Shale natural gas results in significant emissions of VOC and greenhouse gases, which are summarized in Table 19. Emissions of VOC were 10 tpd in 2007 and are expected to increase to 15 tpd by 2009. Greenhouse gas emissions, largely resulting from fugitive releases of methane, were approximately 670 tpd in 2007 and will be approximately 1100 tpd in 2009.

Table 19. Emissions from Natural Gas Processing.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Processing Fugitives	6.7	0.16	22	464	10	0.26	35	727
Outside Metro Processing Fugitives	3.0	0.07	10	210	4.7	0.12	16	329
Processing Fugitives Total	**10**	**0.24**	**32**	**674**	**15**	**0.37**	**50**	**1056**

iv. Transmission Fugitives

Transmission of Barnett Shale natural gas results in significant emissions of greenhouse gases and VOC. Greenhouse gas emissions from transmission fugitives are larger than from any other source category except compressor engine exhausts. Emissions of VOC in 2007 from transmission were approximately 18 tpd in 2007 and are estimated to be 28 tpd in 2009. Greenhouse gas emissions from methane fugitives result in emissions of approximately 5500 tpd in 2007 and 8600 tpd in 2009. Emissions are summarized in Table 20.

Table 20. Emissions from Natural Gas Transmission Fugitives.

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH4	CO2e	VOC	HAPs	CH4	CO2e
D-FW Metro Transmission Fugitives	12	0.29	181	3799	19	0.46	283	5952
Outside Metro Transmission Fugitives	5.5	0.13	82	1718	8.6	0.21	128	2691
Transmission Fugitives Total	**18**	**0.43**	**262**	**5517**	**28**	**0.67**	**411**	**8643**

4.3 All Sources Emission Summary

Emissions from all source categories in the Barnett Shale area are summarized in Table 21-1 on an annual average basis, and are summarized in Table 12-2 on a peak summer basis. Annual average emissions for 2009 of ozone and particulate precursors (NO_x and VOC) were approximately 191 tpd, and peak summer emissions of these compounds were 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 133 tpd during the summer (Tarrant, Denton, Parker, Johnson, and Ellis).

Estimates of greenhouse gas emissions from the sector as a whole were quite large, with 2009 emissions of approximately 33,000 tpd. The greenhouse gas contribution from compressor engines was dominated by carbon dioxide, while the greenhouse gas contribution from all other sources was dominated by methane. Emissions of HAPs were significant from Barnett Shale activities, with emissions in 2009 of 6.4 tpd in 2009 on an annual average, and peak summer emissions of 17 tpd.

Table 21. Emissions Summary for All Source Categories.

Table 21-1. Annual Average Emissions from All Sources.

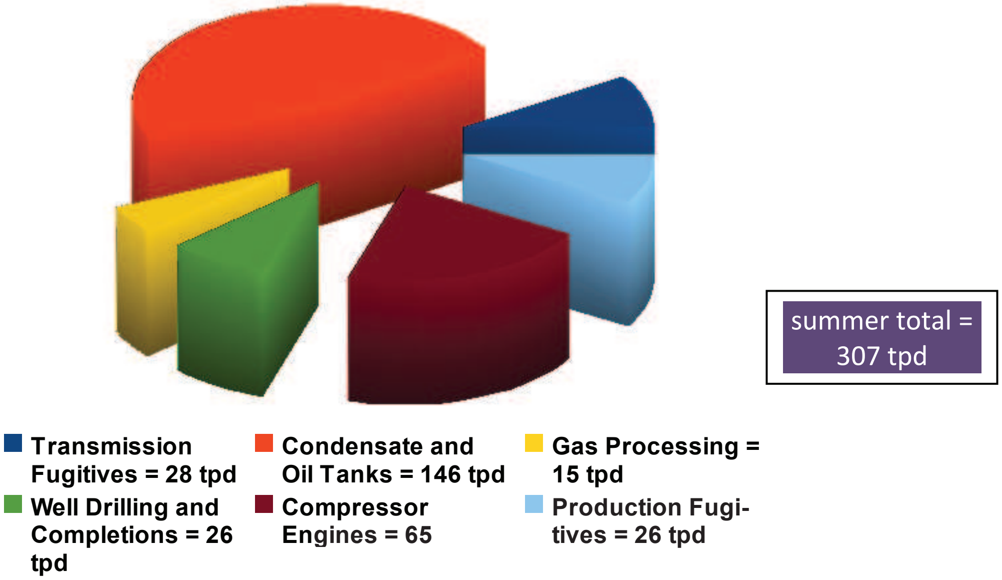
	2007					2009				
	Pollutant (tpd)					Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	19	0.39	4.5	95	0	30	0.60	7.0	149
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**100**	**4.6**	**673**	**22375**	**51**	**139**	**6.4**	**945**	**32670**

Table 21-2. Peak Summer Emissions from All Sources.

	2007					2009				
	Pollutant (tpd)					Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	93	7.2	15	308	0	146	11	23	483
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
Total Daily Emissions (tpd)	**56**	**174**	**11**	**683**	**22588**	**51**	**255**	**17**	**961**	**33004**

Emissions of nitrogen oxides from oil and gas production in the Barnett Shale were dominated by emissions from compressor engines, with a smaller contribution from well drilling and fracing pump engines. All source categories in the Barnett Shale contributed to VOC emissions, but the largest group of VOC sources was condensate tank vents. Figure 6 presents the combined emissions of NO_x and VOC during the summer from all source categories in the Barnett Shale.

Figure 6. Summer Emissions of Ozone & Fine Particulate Matter Precursors (NO_x and VOC) from Barnett Shale Sources in 2009.



4.4 Perspective on the Scale of Barnett Shale Air Emissions

Barnett Shale oil and gas production activities are significant sources of air emissions in the north-central Texas area. To help put the levels of Barnett Shale emissions into context, recent government emissions inventories for the area were reviewed, and emission rates of smog precursor emissions were examined.

The Dallas-Fort Worth area is home to two large airports, Dallas Love Field and Dallas-Fort Worth International Airport, plus a number of smaller airports. A recent emissions inventory has estimated 2009 NO_x emissions from all area airports to be approximately 14 tpd, with VOC emissions at approximately 2.6 tpd, resulting in total ozone and particulate matter precursor emissions of approximately 16 tpd. (22-24) For comparison, emissions of VOC + NO_x in summer 2009 from just the compressor engines in the Barnett Shale area will be approximately 65 tpd, and summer condensate tanks emissions will be approximately 146 tpd. In 2009, even after regulatory efforts to reduce NO_x emissions from certain compressor engine types, Barnett Shale oil and gas emissions will be many times the airports' emissions.

Recent state inventories have also compiled emissions from on-road mobile sources like cars, trucks, etc., in the 9-county D-FW metropolitan area.(25) By 2009, NO_x + VOC emissions from mobile sources in the 9-county area were estimated by the TCEQ to be approximately 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd (Denton, Tarrant, Parker, Johnson, and Ellis). As indicated earlier, summer oil and gas emissions in the 5-counties of the D-FW metropolitan area with significant oil and gas production was estimated to be 165 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties (165 vs. 121 tpd).

Emissions of NO_x and VOC in the summer of 2009 from all oil and gas sources in the Barnett Shale 21-county area will exceed emissions from on-road mobile sources in the D-FW metropolitan area by more than 30 tpd (307 vs. 273 tpd).

Figure 7 summarizes summer Barnett Shale-related emissions, plus TCEQ emission estimates from the airports and on-road mobile sources. Figure 8 presents annual average emissions from these sources.

Figure 7. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Summer 2009 Emissions).

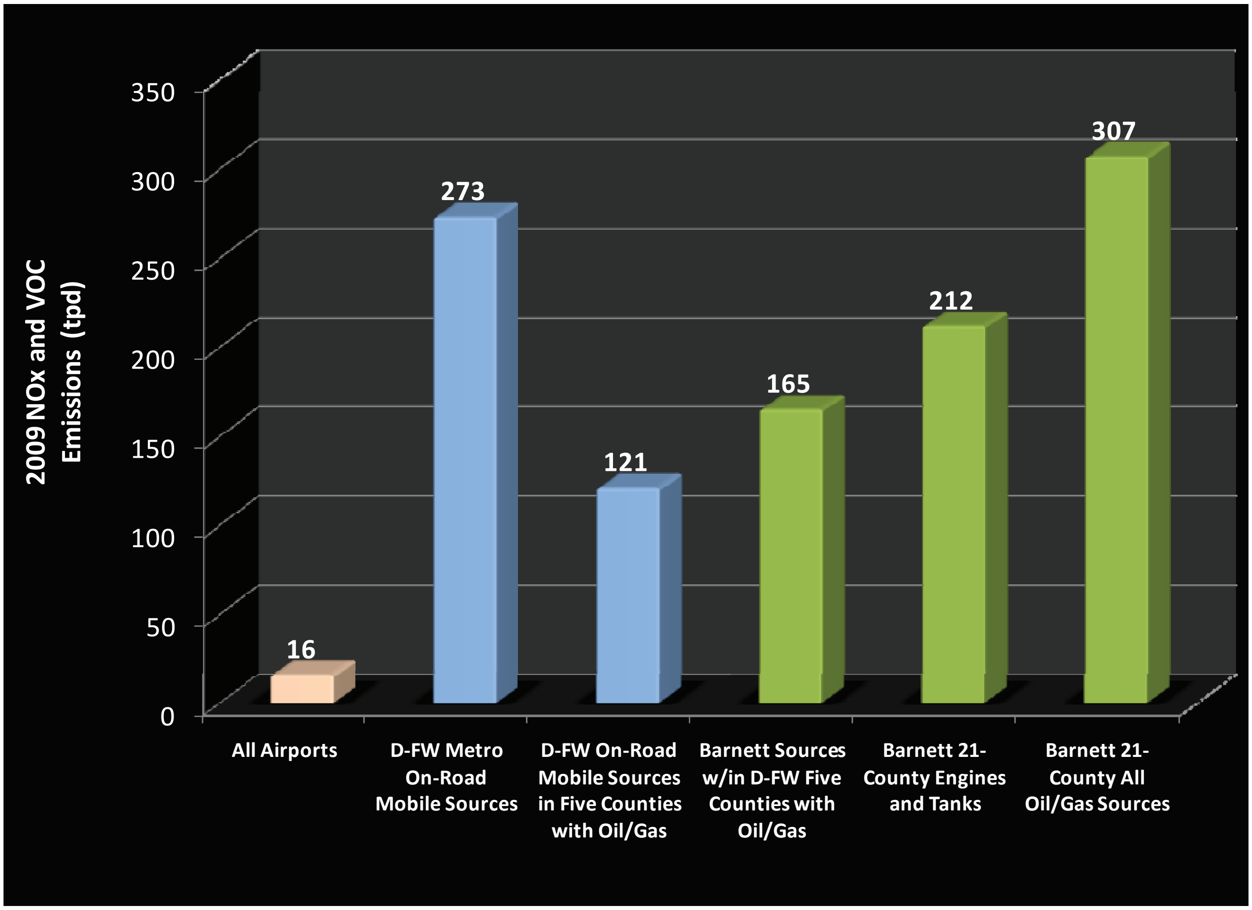
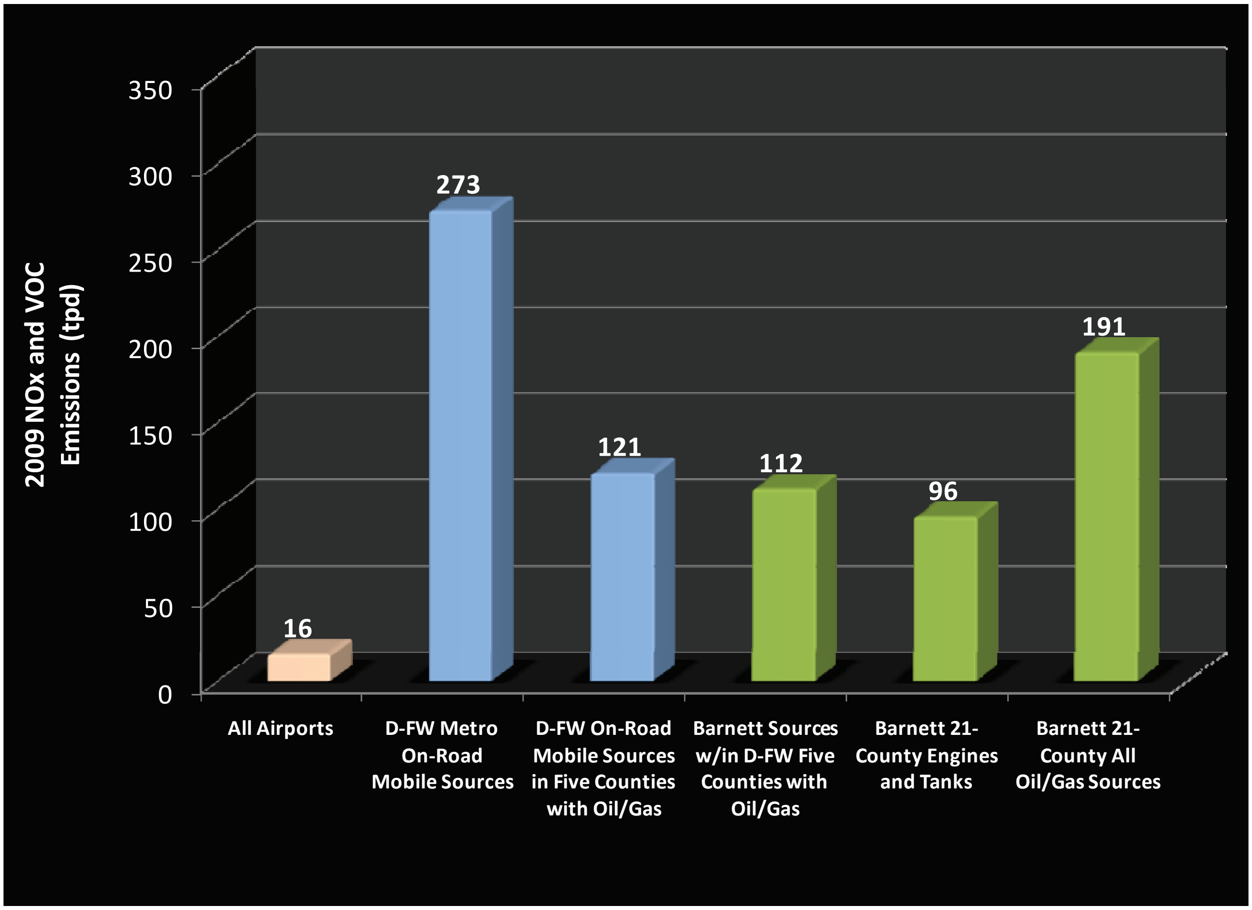


Figure 8. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Annual Average 2009 Emissions).



5.0 EMISSIONS REDUCTION OPPORTUNITIES

The previous sections of this report have estimated the emission rates of ozone and particulate matter precursor compounds, air toxic compounds, and greenhouse gases from different oil and gas sources in the Barnett Shale area. For several of these source categories, off-the-shelf options are available which could significantly reduce emissions, resulting in important air quality benefits. Some of these emissions reductions would also result in increased production of natural gas and condensate, providing an economic payback for efforts to reduce emissions.

5.1 Compressor Engine Exhausts

Compressors in oil and gas service in the Barnett Shale perform vital roles, to either help get oil and gas out of the shale, to increase pressures of gas at the surface, and to provide the power for the large interstate pipeline systems that move high volumes of gas from production to processing and to customers. At present, most of the work to operate the compressors comes from natural gas-fired internal combustion engines, and these engines can be significant sources of emissions.

New TCEQ rules are scheduled to become effective in early 2009 and they will reduce NO_x, VOC, and other emissions from a subset of the engines in the Barnett Shale – those that are currently in the D-FW metropolitan area that had typically not reported into the Texas point source emissions inventory for major sources. These rules are a good first step in addressing emissions from these sources, which had previously gone unnoticed in state emission inventory and regulatory efforts.

However, engines outside the D-FW metropolitan area are not subject to the rule. And even within the metropolitan area, the rule will not have the effect of greatly reducing emissions in 2009 compared to 2007 levels, since growth in oil and gas production (and the new engines that are going to be required to power the growth) will begin to overtake the benefits that come from reducing emissions from the pre-2009 fleet (see Table 14).

Two available options for reducing emissions from engines in the Barnett Shale area are: (1) extending the TCEQ 2009 engine regulation to all engines in the Barnett Shale, and (2) replacing internal combustion engines with electric motors as the sources of compression power.

i. Extending the 2009 Engine Rule to Counties Outside the D-FW Metropolitan Area

Regulations adopted by TCEQ for the D-FW metropolitan area and scheduled to take effect in early 2009 will limit NO_x emissions from engines larger than 50 horsepower.(7) Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. Applying these rules to engines outside the metropolitan area would reduce 2009 NO_x emissions from a large number of engines, in particular, rich burn engines between 50 to 500 hp. Emissions of NO_x in 2009 from the engines outside the metropolitan area would drop by approximately 6.5 tpd by extending the D-FW engine rule, an amount greater than mobile source emissions in all of Johnson County (4 tpd), or more than 50% of the emissions from Dallas-Fort Worth International Airport (12.6 tpd).

Extending the D-FW engine rule to counties outside the metropolitan area would likely result in many engine operators installing NSCR systems on rich burn engine exhausts. These systems would not only reduce emissions of NO_x, but they would also be expected to reduce emissions of VOC, the other ozone and particulate matter precursor, by approximately 75% or greater.(26a) Additional co-benefits of NSCR installations would include lower emissions of organic HAP compounds like benzene and formaldehyde, lower emissions of methane, and lower emissions of carbon monoxide. The level of HAP, methane, and carbon monoxide control would also be expected to be 75% or greater with typical NSCR installations.(26a)

Analyses of NSCR installations and operating costs by numerous agencies have indicated that the technology is very cost effective. For example, the Illinois Environmental Protection Agency estimated in 2007 that NSCR could control NO_x from 500 hp engines at approximately \$330/ton.(26b) The U.S. EPA in 2006 estimated that NSCR could control NO_x from 500 hp engines at approximately \$92 to 105/ton.(27) A 2005 report examining emissions reductions from compressor engines in northeast Texas estimated NO_x cost effectiveness for NSCR at \$112-183/ton and identified VOC reductions as an important co-benefit.(28) These costs are well under the cost effectiveness values of \$10,000 to \$20,000 per ton often used as upper limits in $PM_{2.5}$, ozone, and regional haze (visibility) regulatory programs. The simultaneous HAPs and methane removal that would occur with NSCR use provide further justification for extending the D-FW engine rule to counties outside the metropolitan area.

ii. Electric Motors Instead of Combustion Engines for Compressor Power

When considering NO_x, VOC, HAPs, and greenhouse gas emissions from compressor engines, it is important to understand that the work to move the gas in the pipelines is performed by the compressors, which by themselves produce no direct combustion emissions. The emissions come from the exhaust of the internal combustion engines, which are fueled with a small amount of the available natural gas. These engines provide the mechanical power to run the compressors. The 2007 TCEQ engine survey and the most recent point source emissions inventory indicate that installed compressor engine capacity throughout the Barnett Shale was approximately 1,400,000 hp in 2007, and capacity is likely to increase to over 2,100,000 hp by 2009.

As an alternative to operating the compressors in the Barnett Shale with millions of hp of natural gas burning-engines, the compressors could be operated with electrically-driven motors. The electrification of the wellhead and compressor station engine fleet in the Barnett Shale area has the potential to deliver significant reductions in emissions in North Central Texas. The use of electric motors instead of internal combustion engines to drive natural gas compressors is not new to the natural gas industry, and numerous compressors driven by electric motors are operational throughout Texas. Unfortunately, current regulations have not yet required their use in the Barnett Shale.

A few of the many examples of electrically-driven natural gas compressors, positive technical assessments, and industrial experience with their use in Texas and throughout the U.S., include:

- The Interstate Natural Gas Association of America: "One advantage of electric motors is they need no air emission permit since no hydrocarbons are burned as fuel. However, a highly reliable source of electric power must be available, and near the station, for such units to be considered for an application." (29)
- The Williams natural gas company: "The gas turbine and reciprocating engines typically use natural gas from the pipeline, where the electric motor uses power from an electric transmission line. Selection of this piece of equipment is based on air quality, available power, and the type of compressor selected. Typically electric motors are used when air quality is an issue." (30)
- JARSCO Engineering Corp.: "The gas transmission industry needs to upgrade equipment for more capacity. The new high-speed electric motor technology provides means for upgrading, at a fraction of the life cycle costs of conventional gas powered equipment."(31)
- Pipeline and Gas Journal, June 2007: "Important factors in favor of electric-driven compressor stations that should be considered in the feasibility analysis include the fact that the fuel gas for

gas turbine compressor stations will be transformed into capacity increase for the electrically-driven compressor station, and will therefore add revenue to this alternative..." (32)

- Prime mover example: Installations in 2007 at Kinder Morgan stations in Colorado of +10,000 hp electric-driven compressor units. (33)
- Wellhead example: Installations in Texas of wellhead capacity (5 to 400 hp) electrically-driven compressors. (34,35)
- Mechanical Engineering Magazine, December 1996: "Gas pipeline companies historically have used gas-fired internal-combustion engines and gas turbines to drive their compressors. However, this equipment emits nitrogen oxides....According to the Electric Power Research Institute, it is more efficient to send natural gas to a combined-cycle power plant to generate electricity transmitted back to the pipeline compressor station than to burn the natural gas directly in gas-fired compressor engines."(36)
- The Dresser-Rand Corporation: "New DATUM-C electric motor-driven compressor provides quiet, emissions free solution for natural gas pipeline applications – An idea whose time had come." (37)
- Occidental Oil and Gas Corporation: "Converting Gas-Fired Wellhead IC Engines to Electric Motor Drives: Savings $23,400/yr/unit." (38)

The use of an electric motor instead of a gas-fired engine to drive gas compression eliminates combustion emissions from the wellhead or compressor station. Electric motors do require electricity from the grid, and in so far as electricity produced by power plants that emits pollutants, the use of electric motors is not completely emissions free. However, electric motor use does have important environmental benefits compared to using gas-fired engines.

Modern gas-fired internal-combustion engines have mechanical efficiencies in the 30-35% range, values that have been relatively static for decades. It is doubtful that dramatic increases in efficiency (for example, to 80 or 90%) are possible anytime in the near future. This means that carbon dioxide emissions from natural gas-fired engines at wellheads and compressor stations are not likely to drop substantially because of efficiency improvements. In addition, the scrubbing technology that is used in some large industrial applications to separate CO_2 from other gases also is unlikely to find rapid rollout to the thousands of comparatively-smaller exhaust stacks at natural gas wellheads and compressor stations. The two facts combined suggest that the greenhouse gas impacts from using internal combustion engines to drive compressors are likely to be a fixed function of compression demand, with little opportunity for large future improvements.

In contrast, the generators of grid electric power are under increasing pressure to lower greenhouse gas emissions. Wind energy production is increasing in Texas and other areas. Solar and nuclear power projects are receiving renewed interest from investors and regulators. As the electricity in the grid is produced by sources with lower carbon dioxide emissions, so then the use of electric motors to drive natural gas pipelines becomes more and more climate friendly.

Stated another way, carbon dioxide emissions from gas-fired engines are unlikely to undergo rapid decreases in coming years, whereas the electricity for operating electric motors is at a likely carbon-maximum right now. Electric-powered compression has a long-term potential for decreased climate impact, as non-fossil fuel alternatives for grid electricity generation expand in the future.

Costs: Estimates were made of the costs were switching from IC engines to electric motors for compression. Costs at sites in the Barnett Shale are highly time and site specific, depending on the cost of electricity and the value of natural gas, the numbers of hours of operation per year, the number and sizes of compressors operated, and other factors.

For this report, sample values were determined for capital, operating and maintenance, and operating costs of 500 hp of either IC engine capacity or electric motor capacity for a gas compressor to operate for 8000 hours per year at a 0.55 load factor. Electric power costs were based on $8/month/kW demand charge, $0.08/kWh electricity cost, and 95% motor mechanical efficiency. Natural gas fuel costs were based on $7.26/MMBtu wellhead natural gas price and a BSFC of 0.0085 MMBtu/hp-hr.

With these inputs, the wellhead value of the natural gas needed to operate a 500 hp compressor with an IC engine for 1 year is approximately $136,000. This is lower than the costs for electricity to run a comparable electric motor, which would be approximately $174,000. In addition to these energy costs, it is important to also consider operating and maintenance (O&M) and capital costs. With an IC engine O&M cost factor of $0.016/hp in 2009 dollars, O&M costs would be approximately $35,000. With an electric motor O&M cost factor of $0.0036/kWh in 2009 dollars, O&M costs would be approximately $6200, providing a savings of nearly $30,000 per year in O&M costs for electrical compression, nearly enough to compensate for the additional energy cost incurred from the additional price premium on electricity in Texas compared to natural gas.

With an IC engine capital cost factor of $750/hp in 2009 dollars, the cost of a 500 hp compressor engine would be approximately $370,000. With an electric motor cost factor of $700/kW, the cost of 500 hp of electrically-powered compression would be approximately $260,000.

The combined energy (electricity or natural gas), O&M, and capital costs for the two options are shown in Table 22, assuming a straight 5-year amortization of capital costs. The data show that there is little cost difference in this example, with a slight cost benefit of around $12,000/year for generating the compression power with an electric motor instead of an IC engine. While this estimate would vary from site to site within the Barnett Shale, there appears to be cost savings, driven mostly by reduced initial capital cost, in favor of electrical compression in the Barnett Shale. In addition to the potential cost savings of electrical compression over engine compression, the lack of an overwhelming economic driver one way or the other allows the environmental benefits of electric motors over combustion engines to be the deciding factor on how to provide compression power in the area.

Table 22. Costs of IC Engine and Electric Motor Compression [example of 500 hp installed capacity].

	IC Engine ($/year)	Electric Motor ($/year)
energy (NG or electricity)	136,000	174,000
O&M	35,000	6,200
capital	74,000	52,000
Total	**245,000**	**232,000**

5.2 Oil and Condensate Tanks

Oil and condensate tanks in the Barnett Shale are significant sources of multiple air pollutants, especially VOC, HAPs, and methane. Multiple options exist for reducing emissions from oil and condensate tanks, including options that can result in increased production and revenue for well operators.(14) This section will discuss two of these options: flares and vapor recovery units.

i. Vapor Recovery Units

Vapor recovery units (VRU) can be highly effective systems for capturing and separating vapors and gases produced by oil and condensate tanks. Gases and vapors from the tanks are directed to the inlet side of a compressor, which increases the pressure of the mixture to the point that many of the moderate and higher molecular weight compounds recondense back into liquid form. The methane and other light gases are directed to the inlet (suction) side of the well site production compressors to join the main flow of natural gas being produced at the well. In this way, VRU use increases the total production of gas at the well, leading to an increase in gas available for metering and revenue production. In addition, liquids produced by the VRU are directed back into the liquid phase in the condensate tank, increasing condensate production and the income potential from this revenue stream. Vapor recovery units are estimated to have control efficiencies of greater than 98%.(14)

The gases and vapors emitted by oil and condensate tanks are significant sources of air pollutants, and the escape of these compounds into the atmosphere also reduces income from hydrocarbon production. With a wellhead value of approximately $7/MMBtu, the 7 tpd of methane that is estimated to be emitted in 2009 from condensate tanks in the Barnett Shale have a value of over $800,000 per year. Even more significantly, a price of condensate at $100/bbl makes the 30 tpd of VOC emissions in 2009 from the tanks in the Barnett Shale potentially worth over $10 million per year.

While flaring emissions from tanks in the Barnett Shale would provide substantial environmental benefits, especially in terms of VOC and methane emissions, capturing these hydrocarbons and directing them into the natural gas and condensate distribution systems would provide both an environmental benefit and a very large potential revenue stream to oil and gas producers.

ii. Enclosed Flares

Enclosed flares are common pollution control and flammable gas destruction devices. Enclosed flares get their name because the flame used to ignite the gases is generated by burner tips installed within the stack well below the top. The flames from enclosed flares are usually not visible from the outside, except during upset conditions, making them less objectionable to the surrounding community compared to open (unenclosed) flares.

Using a flare to control emissions from tanks involves connecting the vents of a tank or tank battery to the bottom of the flare stack. The vapors from oil and condensate tanks are sent to the flare, and air is also added to provide oxygen for combustion. The vapors and air are ignited by natural gas pilot flames, and much of the HAP, VOC, and methane content of the tank vapors can be destroyed. The destruction efficiency for flares can vary greatly depending on residence time, temperature profile, mixing, and other factors. Properly designed and operated flares have been reported to achieve 98% destruction efficiencies.

Applying 98% destruction efficiency to the Barnett Shale oil and condensate tanks emissions estimates shown in Table 16 results in potential emission reductions of 30 tpd of VOC, 0.6 tpd of HAPs, and 7 tpd of methane. These reductions are substantial and would provide large benefits to the ozone and PM precursor, HAPs, and greenhouse gas emission inventory of the Barnett Shale area. The use of flares, however, also has several drawbacks. One of these is that tank vapor flares need a continuous supply of pilot light natural gas, and reports have estimated pilot light gas consumption at around 20 scfh/flare.(14)

Table 23 presents a summary of the results of an economic analysis performed in 2006 by URS Corporation for using flares or vapor recovery units to control emissions from a tank battery in Texas.(14) Capital costs were estimated by URS with a 5-year straightline amortization of capital. Flow from the tank battery was 25Mscf/day and VOC emissions were approximately 211 tpy. Costs were in 2006 dollars.

Table 23. Economics of Flares and Vapor Recovery Units.

Control Option	Total Installed Capital Cost ($)	Annual Installed Operating Cost ($/yr)	Operating Cost ($/yr)	Value Recovered ($/yr)	VOC Destruction Cost Effectiveness ($/ton VOC)
Enclosed Flare	40,000	8000	900	NA	40
VRU	60,000	12000	11,400	91,300	($320)*

*VRU produces positive revenue, resulting in zero cost for VOC control, after accounting for value of recovered products.

The URS analysis indicated that flares were able to cost effectively reduce VOC emissions at $40/ton, while VRU units produced no real costs and quickly generated additional revenue from the products recovered by VRU operation. There was a less-than 1 year payback on the use of a VRU system, followed by years of the pollution control device becoming steady revenue source.

5.3 Well Completions

Procedures have been developed to reduce emissions of natural gas during well completions. These procedures are known by a variety of terms, including "the green flowback process" and "green completions." (39,40) To reduce emissions, the gases and liquids brought to the surface during the completion process are collected, filtered, and then placed into production pipelines and tanks, instead of being dumped, vented, or flared. The gas cleanup during a "green" completion is done with special temporary equipment at the well site, and after a period of time (days) the gas and liquids being produced at the well are directed to the permanent separators, tanks, and piping and meters that are installed at the well site. Green completion methods are not complex technology and can be very cost effective in the Barnett Shale. The infrastructure is well-established and gathering line placement for the initial collection of gas is not a substantial risk since wells are successfully drilled with a very low failure rate.

Emissions during well completions depend on numerous site-specific factors, including the pressure of the fluids brought to the surface, the effectiveness of on-site gas capturing equipment, the control efficiency of any flaring that is done, the chemical composition of the gas and hydrocarbon liquids at the drill site, and the duration of drilling and completion work before the start of regular production.

Some recent reports of the effectiveness of green completions in the U.S. are available, including one by the U.S. EPA which estimated 70% capture of formerly released gases with green completions, and another report by Williams Corporation which found that 61% to 98% of gases formerly released during well completions were captured with green completions.(40-41) Barnett Shale producer Devon Energy is using green completions on its wells, and they reported $20 million in profits from natural gas and condensate recovered by green completed wells in a 3 year period.(42)

If green completion procedures can capture 61% to 98% of the gases formerly released during well completions, the process would be a more environmentally friendly alternative to flaring of the gases, since flaring destroys a valuable commodity and prevents its beneficial use. Green completions would also certainly be more beneficial than venting of the gases, since this can release very large quantities of methane and VOCs to the atmosphere. Another factor in favor of capturing instead of flaring is that flaring can produce carbon dioxide (a greenhouse gas), carbon monoxide, polycyclic aromatic hydrocarbons, and particulate matter (soot) emissions.

5.4 Fugitive Emissions from Production Wells, Gas Processing, and Transmission

Fugitive emissions from the production wells, gas processing plants, gas compressors, and transmission lines in the Barnett Shale can be minimized with aggressive efforts at leak detection and repair. Unlike controlling emissions from comparatively smaller numbers of engines or tanks (numbering in the hundreds or low thousands per county), fugitive emissions can originate from tens of thousands of valves, flanges, pump seals, and numerous other leak points. While no single valve or flange is likely to emit as much pollution as a condensate tank or engine exhaust stack, the cumulative mass of all these fugitives can be substantial. There are readily-available measures that can reduce fugitive emissions.

i. Enhanced Leak Detection and Repair Program

The federal government has established New Source Performance Standards for natural gas processing plants a.k.a. NSPS Subpart KKK.(43) These standards require regularly scheduled leak detection, and if needed, repair activities for items such as pumps, compressors, pressure-relief valves, open-ended lines, vapor recovery systems, and flares. The NSPS applies to plants constructed or modified after January 20, 1984. The procedures and standards in the processing plant NSPS are generally based on the standards developed for the synthetic organic manufacturing chemicals industry.(44)

Fugitive emissions from oil and gas wells, separators, tanks, and metering stations are not covered by the processing plant NSPS. Nonetheless, the leak detection and repair protocols established in the NSPS could certainly be used to identify fugitive emissions from these other items. Leak detection at processing plants covered by the NSPS is performed using handheld organic vapor meters (OVMs), and inspections are required to be done on a specified schedule. These same procedures could be used at every point along the oil and gas system in the Barnett Shale to identify and reduce emissions of VOCs and methane. Doing so would reduce emissions, and by doing so, increase production and revenue to producers.

It is difficult to estimate the exact degree of emission reductions that are possible with fugitive emission reduction programs. The large and varied nature of fugitive emission points (valves, fittings, etc.) at production wells, processing plants, and transmission lines means that each oil and gas related facility in the Barnett Shale will have different options for reducing fugitive emissions. In general, leak detection and repair programs can help identify faulty units and greatly reduce their emissions.

ii. Eliminating Natural Gas-Actuated Pneumatic Devices

The State of Colorado is currently adopting and implementing VOC control strategies to reduce ambient levels of ozone in the Denver metropolitan area and to protect the numerous national parks and wilderness areas in the state. As part of this effort, the state investigated the air quality impacts of oil and gas development, including the impacts of the pneumatically-controlled valves and other devices that are found throughout gas production, processing, and transmission systems. The State of Colorado confirmed the basic conclusions arrived at earlier by EPA and GRI in 1995, that these pneumatic devices can be substantial sources of CH_4, VOC, and HAP emissions.(45,46) Much of the following information on these devices and the strategies to control emissions is based on a review of the recent work in Colorado.

Valves and similar devices are used throughout the oil and gas production, processing, and transmission systems to regulate temperature, pressure, flow, and other process parameters. These devices can be operated mechanically, pneumatically, or electrically. Many of the devices used in the natural gas sector are pneumatically operated. Instrument air (i.e. compressed regular air) is used to power pneumatic devices at many gas processing facilities, but most of the pneumatic devices at production wells and along transmission systems are powered by natural gas.(46) Other uses of pneumatic devices are for shutoff valves, for small pumps, and with compressor engine starters.

As part of normal operation, most pneumatic devices release or “bleed”gas to the atmosphere. The release can be either continuously or intermittently, depending on the kind of device. In 2003 U.S. EPA estimated that emissions from the pneumatic devices found throughout the production, processing, and transmission systems were collectively one of the largest sources of methane emissions in the natural gas industry. Some U.S. natural gas producers have reduced natural gas emissions significantly by replacing or retrofitting "high-bleed" pneumatic devices. High-bleed pneumatic devices emit at least 6 standard cubic feet gas per hour.(46) Actual field experience is demonstrating that up to 80 percent of all high-bleed devices in natural gas systems can be replaced or retrofitted with low-bleed equipment.

The replacement of high-bleed pneumatic devices with low-bleed or no-bleed devices can reduce natural gas emissions to atmosphere by approximately 88 or 98 percent, respectively.(21, 47) Anadarko Petroleum Corporation estimated that VOC emissions from their pneumatic devices will be reduced by 464 tpy once 548 of their pneumatic controllers are retrofitted in Colorado.(46)

It may not be possible, however, to replace all high-bleed devices with low or no bleed alternatives. In the state of Colorado, it was estimates that perhaps up to 20 percent of high-bleed devices could not be retrofitted or replaced with low-bleed devices. Some of these included very large devices requiring fast and/or precise responses to process changes which could not yet be achieved with low-bleed devices.

But even for these devices that appear to require high-bleed operation, alternatives are available. Natural gas emissions from both high bleed and low bleed devices can be reduced by routing pneumatic discharge ports into a fuel gas supply line or into a closed loop controlled system. Another alternative is replacing the natural gas as the pneumatic pressure fluid with pressurized air. Instrument pressurized air systems are sometimes installed at facilities that have a high concentration of pneumatic devices, full-time operator presence, and are on a power grid. In an instrument pressurized air system, atmospheric air is compressed, stored in a volume tank, filtered, and dried. The advantage of a pressurized air system for operating pneumatic devices is that operation is the same whether they air or natural gas is used. Existing pneumatic gas supply piping, control instruments, and valve actuators can be reused when converting from natural gas to compressed air.

The U.S. EPA runs a voluntary program, EPA Natural Gas STAR, for companies adopting strategies to reduce their methane emissions. Experience from companies participating in the program indicates that strategies to reduce emissions from pneumatic devices are highly cost effective, and many even pay for themselves in a matter of months.(46) EPA reports that one company replaced 70 high-bleed pneumatic devices with low-bleed devices and retrofitted 330 high-bleed devices, which resulted in an emission reduction of 1,405 thousand cubic meters per year. At $105/m^3, this resulted in a savings of $148,800 per year. The cost, including materials and labor for the retrofit and replacement, was $118,500, and therefore, the payback period was less than one year. Early replacement (replacing prior to projected end-of-service-life) of a high-bleed valve with a low-bleed valve is estimated to cost $1,350. Based on $3/m^3 gas, the payback was estimated to take 21 months. For new installations or end of service life replacement, the incremental cost difference of high-bleed devices versus low-bleed devices was $150 to $250. Based on $3 per Mcf gas, the payback was estimated to take 5 to 12 months.(46)

Overall, cost-effective strategies are available for reducing emissions and enhance gas collection from pneumatic devices in Barnett Shale area operations. These strategies include:

- Installing low- or no-bleed pneumatic devices at all new facilities and along all new transmission lines;
- Retrofitting or replacing existing high-bleed pneumatic devices with low- or no-bleed pneumatic devices;
- Ensuring that all natural gas actuated devices discharge into sales lines or closed loops, instead of venting to the atmosphere;
- Using pressurized instrument air as the pneumatic fluid instead of natural gas.

6.0 CONCLUSIONS

Oil and gas production in the Barnett Shale region of Texas has increased rapidly over the last 10 years. The great financial benefits and natural resource production that comes from the Barnett Shale brings with it a responsibility to minimize local, regional, and global air quality impacts. This report examined emissions of smog forming compounds, air toxic compounds, and greenhouse gases from oil and gas activity in the Barnett Shale area, and identified methods for reducing emissions.

Emissions of ozone and fine particle smog forming compounds (NOx and VOC) will be approximately 191 tons per day on an annual average basis in 2009. During the summer, VOC emissions will increase, raising the NOx + VOC total to 307 tpd, greater than the combined emissions from the major airports and on-road motor vehicles in the D-FW metropolitan area.

Emissions in 2009 of air toxic compounds from Barnett Shale activities will be approximately 6 tpd on an annual average, with peak summer emissions of 17 tpd.

Emissions of greenhouse gases like carbon dioxide and methane will be approximately 33,000 CO_2 equivalent tons per day. This is roughly comparable to the greenhouse gas emissions expected from two 750 MW coal-fired power plants.

Cost effective emission control methods are available with the potential to significantly reduce emissions from many of the sources in the Barnett Shale area, including

- the use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in of electric motors as an alternative to internal-combustion engines to drive gas compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

Large reductions in greenhouse gas emissions could be achieved through the use of green completion methods on all well completions, with the potential to eliminate almost 200 tpd of methane emissions while increasing revenue for producers by recovering saleable gas. In addition, the replacement of internal combustion engines with electric motors for compression power could reduce smog-forming emissions in the D-FW metropolitan area by 65 tpd. Significant emission reductions could also be achieved with the use of vapor recovery units on oil and condensate tanks, which could eliminate large amounts of VOC emissions. Vapor recovery units on condensate tanks would pay for themselves in a matter of months by generating additional revenue to producers from the gas and condensate that would be captured instead of released to the atmosphere. Fugitive emissions of methane, VOC, and HAPs could be reduced with a program to replace natural gas actuated pneumatic valves with units actuated with compressed air. For those devices in locations where compressed air is impractical to implement, connection of the bleed vents of the devices to sales lines also could greatly reduce emissions.

There are significant opportunities available to improve local and regional air quality and reduce greenhouse gas emissions by applying readily available methods to oil and gas production activities in the Barnett Shale.

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Author's Notes:

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Images on the cover page from the Texas Railroad Commission and the U.S. Department of Energy.

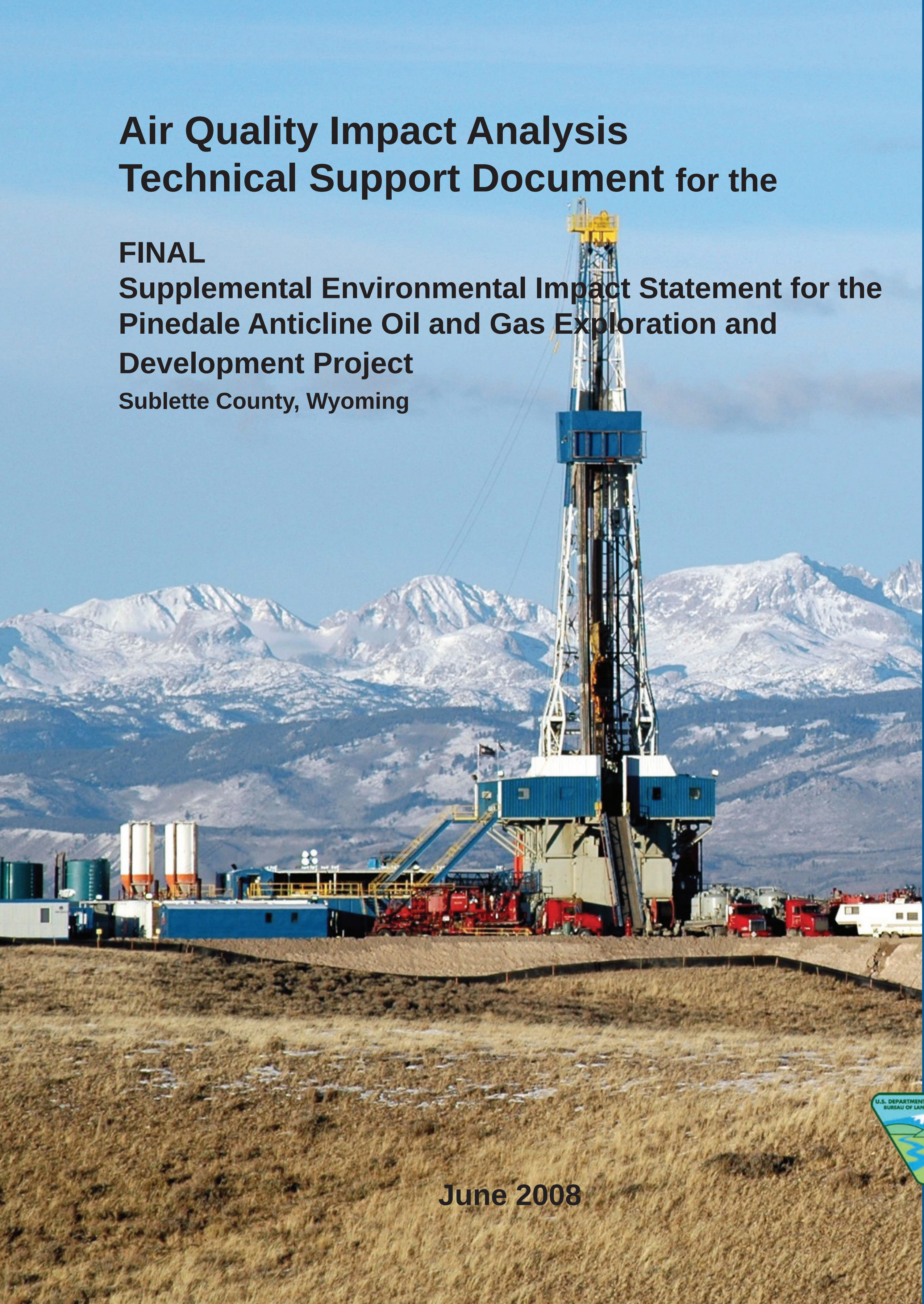
Some typos and spreadsheet errors fixed on 2/8/2009.

Finally, the statements and recommendations in this study are those of the author, and do not represent the official positions of Southern Methodist University.

Air Quality Impact Analysis Technical Support Document for the

FINAL
Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project

Sublette County, Wyoming



June 2008

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

2.0 EMISSIONS INVENTORY

2.1 PROJECT EMISSIONS

The direct project emissions inventory for the PAPA is divided into four sections in Appendix:

- 2005 Actual Emissions Inventory (Section.1),
- 2005 Potential Emissions Inventory (Section 2),
- Proposed Action Emissions Inventory (Section 3), and
- No Action Emissions Inventory (Section 4).

Calculation methods are similar for each emissions inventory except as noted in the following sections. Specific details for each inventory are provided in the respective sections of Appendix F.

Criteria pollutant and hazardous air pollutant (HAP) emissions were inventoried for construction activities, production activities, and ancillary facilities. Criteria pollutants included nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). HAPs consist of n-hexane; benzene, toluene, ethylbenzene, and xylene (BTEX); and formaldehyde. All emission calculations were completed in accordance with WDEQ-AQD oil and gas guidance (WDEQ-AQD 2001), WDEQ-AQD additional guidance for the Jonah and Pinedale Anticline Gas Fields (WDEQ-AQD 2004), stack test data, EPA's AP-42, or other accepted engineering methods (see Appendix F, Section1). Actual 2005 emissions were obtained from emissions inventories submitted by PAPA Operators to WDEQ-AQD, when available. Emissions not quantified in these inventories were conservatively assumed to be equal to those calculated for the 2005 potential emissions inventory.

2.1.1 Construction Emissions

Construction activities are a source of primarily criteria pollutants. Emissions would occur from construction (well pads, roads, gathering pipelines, and ancillary facilities), drilling, completion/testing, traffic, and wind erosion. Well development rates were provided by the Operators based on their future projections for both the Proposed Action Alternative and the No Action Alternative. These well development rates vary by alternative. Detailed well development rates per year can be found in the tables of Appendix F.

Emissions from construction of well pads and roads and traffic include fugitive PM_{10} and $PM_{2.5}$. Other criteria pollutant emissions would occur from diesel combustion in haul trucks and heavy construction equipment. On well pads and resource roads, water would be used for fugitive dust control, with a control efficiency of 50%. On local roads, magnesium chloride would be used for dust control, with a control efficiency of 85%.

After the well pad is constructed, rig-move/drilling would begin. Emissions would include fugitives from unpaved road travel to and from the drilling site. There would be emissions from diesel drilling engines and from boilers in the winter months. Emissions from well completion and testing would include fugitive PM_{10} and $PM_{2.5}$ from traffic. It would also include combustion emissions from diesel fracturing engines and haul truck tailpipes. All completions would be “green completions” with no flaring other than for upset/emergency conditions.

Pollutant emissions would also occur from gathering pipeline installation activities, including general construction activities, travel to and from the pipeline construction site, and diesel combustion from on-site construction equipment.

Construction emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix F.

2.1.2 Production Emissions

Field production equipment and operations would be a source of criteria pollutants and HAPs including BTEX, n-hexane, and formaldehyde. Pollutant emission sources during field production would include:

- combustion engine emissions and fugitive dust from road travel to and from production sites;
- diesel combustion emissions from haul trucks;
- combustion emissions from production site heaters;
- fugitive VOC/HAP emissions from production site equipment leaks;
- condensate storage tank flashing and flashing control;
- glycol dehydrator still vent flashing;
- wind erosion from well pad disturbed areas
- processing units at gas plants; and
- natural gas-fired reciprocating internal combustion compressor engines

Fugitive PM_{10} and $PM_{2.5}$ emissions would occur from road travel and wind erosion from well pad disturbances. Criteria pollutant emissions would occur from diesel combustion in haul trucks traveling in the field during production.

Heaters required at production facilities include separator/indirect line heaters and dehydrator reboiler heaters. These heaters are sources of mainly NO_x and CO as well as small amounts of VOCs. Emissions from these sources were calculated on run-time percentages for both the summer and winter seasons based on data provided by Operators.

VOC and HAP emissions would occur from fugitive equipment leaks (i.e., valves, flanges, connections, pump seals, and opened lines). Condensate storage tank flashing and glycol dehydrator still vent flashing emissions also would include VOC/HAP emissions. VOC and HAP emissions would decrease over the life of an individual well due to declines in condensate and gas production. Emissions from these sources were based on information provided by Operators.

Production emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix F.

2.1.3 Total Field Emissions

Estimates of maximum potential annual emissions in the PAPA under the No Action and Proposed Action alternatives, and for year 2005 are shown in Table 2.1. Maximum potential annual emissions assume construction and production occurring simultaneously in the field for the maximum emissions year for each project alternative.

Table 2.1 Estimated Potential Emissions by Alternative (tpy), Pinedale Anticline Project.

Source	Pollutant	Year 2005	Alternative A (No Action) 2007	Alternative B (Proposed Action) 2009
Construction Emissions				
Drill Rigs	NO_x	2590.9	4066.5	3232.6
	CO	2031.6	2445.2	2307.0
	SO_2	221.0	48.5	55.7
	PM_{10}	133.5	160.4	130.3
	$PM_{2.5}$	133.5	160.4	130.3
	VOC	244.5	292.9	271.3
Fugitives	NO_x	427.4	641.8	559.4
(Pad/Road Construction, Traffic, Completions, etc...)	CO	305.3	493.5	428.1
	SO_2	10.6	15.6	14.4
	PM_{10}	682.2	712.6	415.9
	$PM_{2.5}$	144.8	143.7	82.7
	VOC	192.9	66.1	57.0
Production Emissions				
Compression:	NO_x	421.9	472.2	532.1
	CO	157.7	175.7	235.5
	SO_2	0.0	0.0`	0.0
	PM_{10}	0.0	0.0	0.0
	$PM_{2.5}$	0.0	0.0	0.0
	VOC	320.5	353..5	357.1
Granger Gas Plant	NO_x	301.7	301.7	301.7
(Expansion)	CO	322.8	322.8	322.8
	SO_2	0.0	0.0	0.0
	PM_{10}	0.0	0.0	0.0
	$PM_{2.5}$	0.0	0.0	0.0
	VOC	140.2	140.2	140.2
Wind Erosion	PM_{10}	254.8	357.2	440.8
	$PM_{2.5}$	101.9	142.9	176.3
Fugitives	NO_x	72.2	119.8	108.8
(Heaters, dehys, tanks, traffic, other production equipment, etc…)	CO	251.1	318.7	54.8
	SO_2	0.2	0.5	0.6
	PM_{10}	128.5	311.7	73.7
	$PM_{2.5}$	21.2	51.3	17.8
	VOC	1736.5	1396.2	1150.7
Total	NO_x	3512.4	5602.0	4734.6
	CO	2745.7	3755.9	2978.3
	SO_2	231.8	64.6	70.7
	PM_{10}	1199.0	1541.9	1060.7
	$PM_{2.5}$	401.4	498.3	407.1
	VOC	2494.4	2248.9	1976.3

Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado

Colorado Air Pollution Control Division

<u>Revised Regional Haze Plan</u>
Air Quality Control Commission, approved 01/07/2011

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Preface/Disclaimer

The following document contains Colorado's State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado's programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

Regional Haze Plan	Approval Date
Original	12/21/2007
First Revision	12/19/2008
Second Revision (Fully Replaces All Previous RH Plans)	01/07/2011

Chapter 1 Overview

1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51 Subpart P – Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to 'natural conditions' by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources.

Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31st, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA's concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064,this plan is designed to meet the two requirements stated above for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal.

This SIP is intended to meet the requirements of EPA's Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

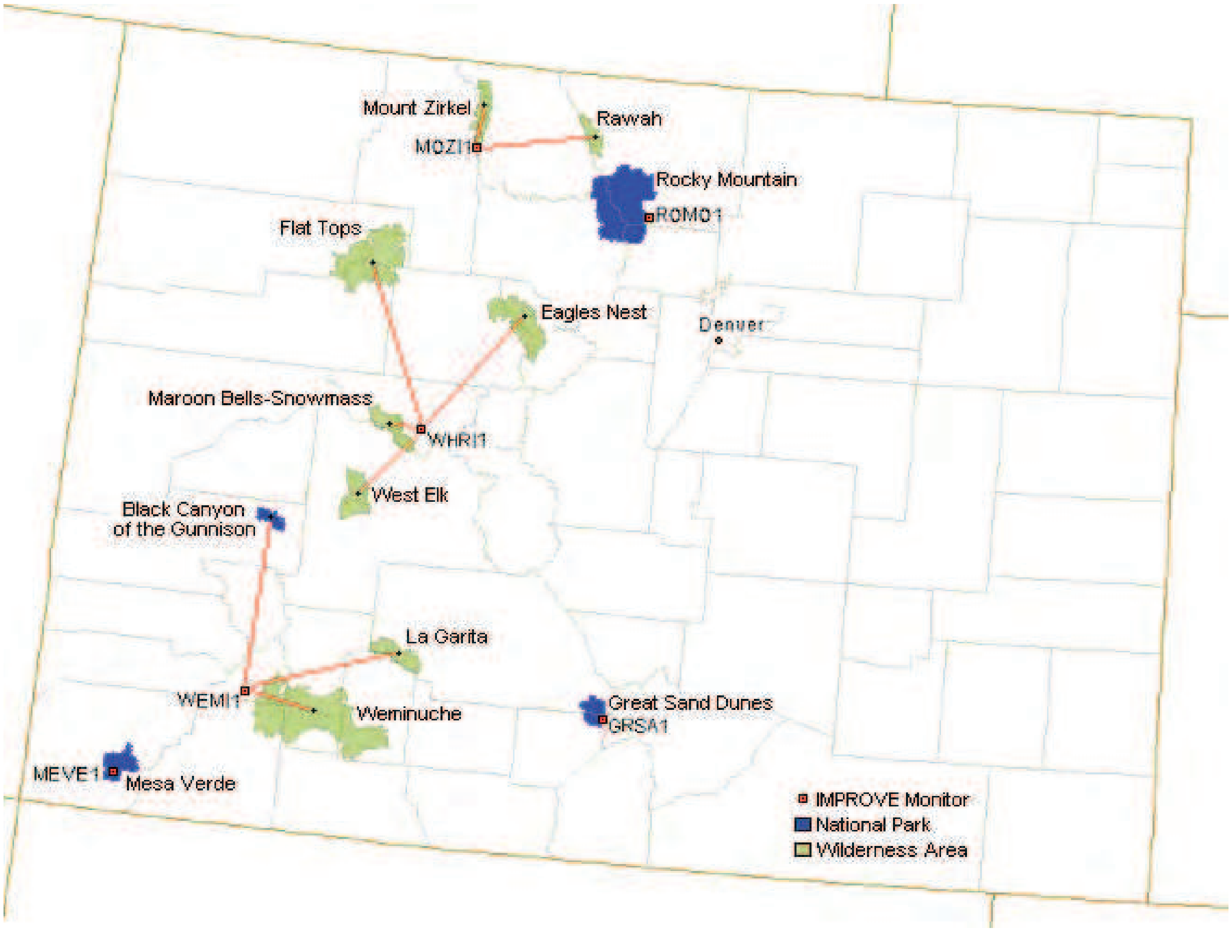
1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

Black Canyon of the Gunnison National Park
Eagles Nest Wilderness Area
Flat Tops Wilderness Area
Great Sand Dunes National Park
La Garita Wilderness Area
Maroon Bells-Snowmass Wilderness Area
Mesa Verde National Park
Mount Zirkel Wilderness Area
Rawah Wilderness Area
Rocky Mountain National Park
Weminuche Wilderness Area
West Elk Wilderness Area

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations



1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006.

As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures. This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado's visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install

and operate BART as expeditiously as practicable, but not later than 5 years after EPA's approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

1.5 Reasonable Progress Towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State's Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state's BART and reasonable progress determinations.

Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.[1] The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

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[1] See http://www.wrapair.org/forums/sp/docs.html

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA’s so called ‘presumptive’ emission limits for NOx and SO2, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state’s conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state's guidance criteria for visibility improvement, and thus would not change the state's determination. Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state's consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state's BART and RP determinations for NOx and SO2 are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state's BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state's position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements.

Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described above, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed above and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado's Class I areas.

Colorado's analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado's concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado's concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NOx emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NOx emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents.

By participating in the WRAP and the Four Corner's Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow.

The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to "develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan." The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA's Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, "The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State….Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network." The federal agencies' monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1 above, and will be met by participating in the IMPROVE network.

Colorado's monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

> To provide regional haze monitoring representing all visibility-protected federal Class I areas

3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado's associated SIP commitment are enumerated below:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
    a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
    b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State's contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
    a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State's emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State's contribution of emissions to impairment in any Class I area.
    b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
    a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/)Through participation in the IMPROVE network, Colorado will partially satisfies the requirement to annually report to EPA visibility data for each of Colorado's Class I areas.

    b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].
    a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.
        i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP's 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (http://www.wrapedms.org/InventoryDesc.aspx). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls
5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].
    a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.
6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].
    a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources

Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical.

The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas. For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations

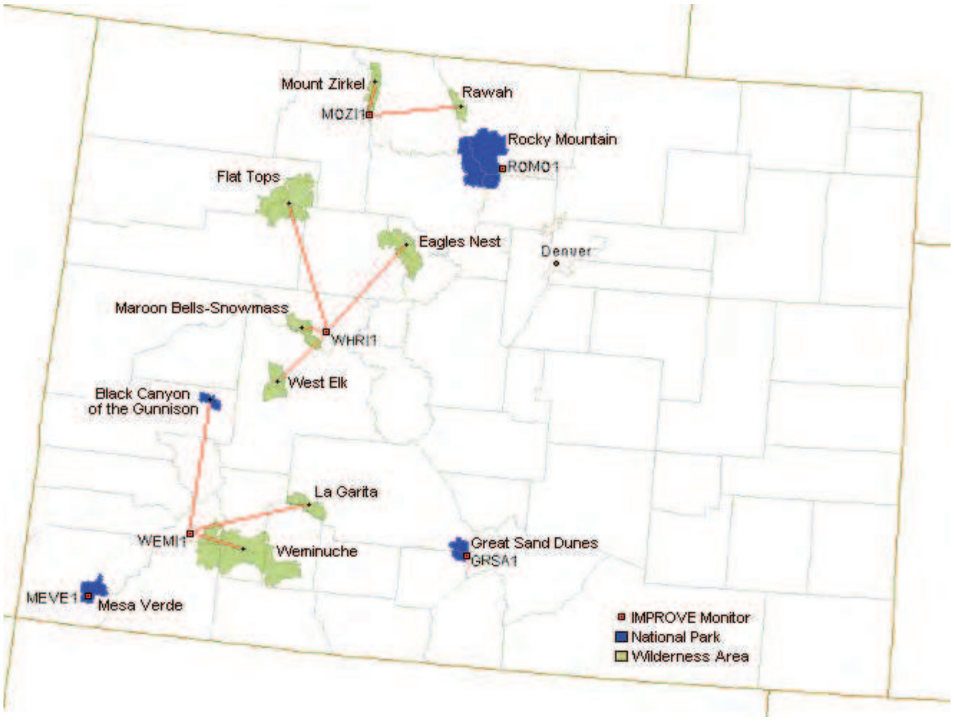

Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

Figure 3-2 Colorado IMPROVE Monitoring Site Information

Mandatory Class I Federal Area	Operating Agency	IMPROVE Monitor	Elevation [ft]	Start Date
Great Sand Dunes National Park	NPS	GRSA1	8,215	5/4/1988
Mesa Verde National Park	NPS	MEVE1	7,142	3/5/1988
Mount Zirkel Wilderness	USFS	MOZI1	10,640	7/30/1994
Rawah Wilderness				
Rocky Mountain National Park	NPS	ROMO1	9,039	9/19/1990
Weminuche Wilderness	USFS	WEMI1	9,072	3/2/1988
Black Canyon of Gunnison NP				
La Garita Wilderness				
Eagles Nest Wilderness	USFS	WHRI1	11,214	7/17/2000
Flat Tops Wilderness				
Maroon Bells-Snowmass Wilderness				
West Elk Wilderness				

3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program[2] to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network. Colorado will continue to work with EPA in refining monitoring

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[2] http://vista.cira.colostate.edu/improve/

strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements.

Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network.

As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v).

The State will use the Fire Emissions Tracking System (FETS)[3] to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations. The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)[4] or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

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[3] http://www.wrapfets.org/

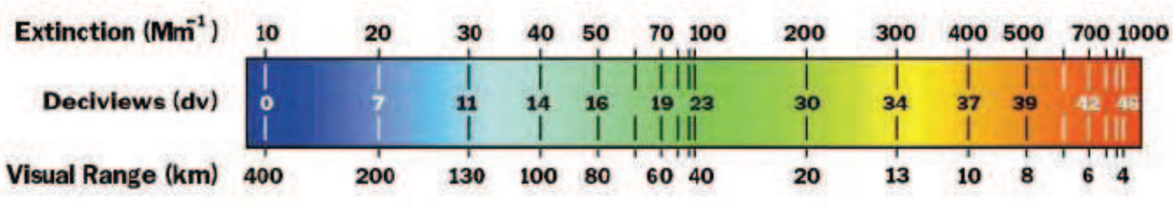
[4] http://pah.cert.ucr.edu/aqm/308/

Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters (1/Mm or Mm^{-1}). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in ***the deciview (dv)*** unit [(40 CFR 51.308(d)(2)]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction (Mm^{-1}), haze index (dv) and visual range (km) are indicated by the following scale:



4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii)]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

4.3 Monitoring Data

Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the “Haze Index”, which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado’s twelve Class I areas.

The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided below for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)

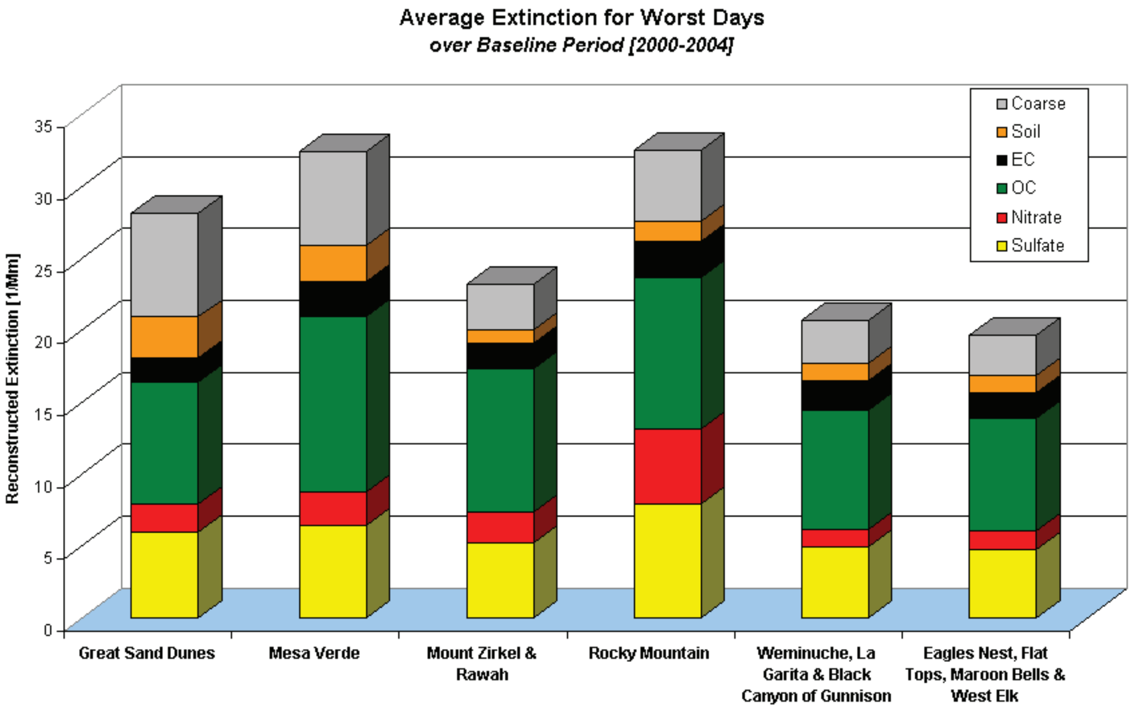
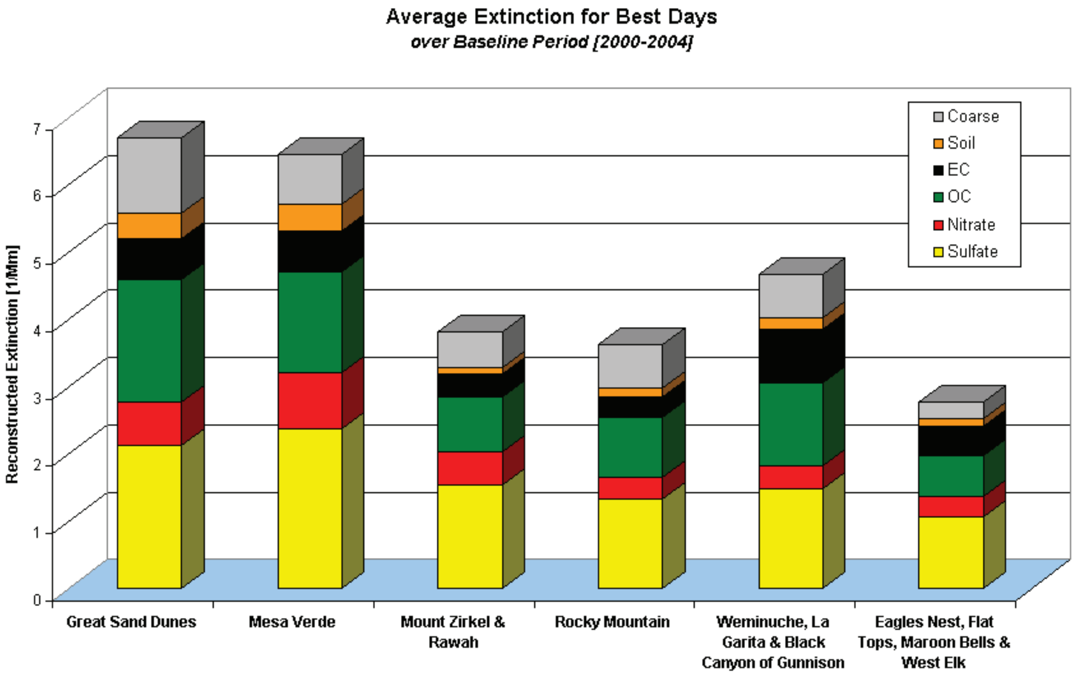


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



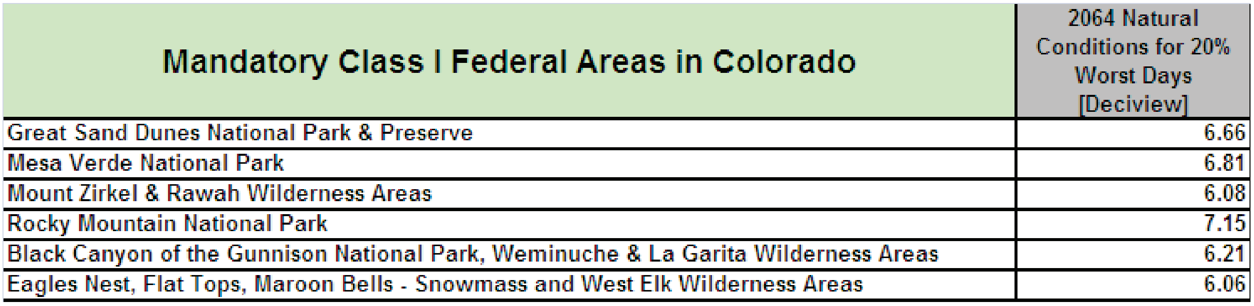
More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)].

Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

Figure 4-3: 2064 Natural Conditions Goal for Worst Days



Mandatory Class I Federal Areas in Colorado	2064 Natural Conditions for 20% Worst Days [Deciview]
Great Sand Dunes National Park & Preserve	6.66
Mesa Verde National Park	6.81
Mount Zirkel & Rawah Wilderness Areas	6.08
Rocky Mountain National Park	7.15
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	6.21
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	6.06

4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B)]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column "2018 Uniform Progress Goal (Deciview)".

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

$$URP = [\text{Baseline Condition} - \text{Natural Condition}] / 60 \text{ years}$$

By multiplying the URP by the number of years in the 1st planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

$$2018\ UPG = [URP] \times [14 \text{ years}]$$

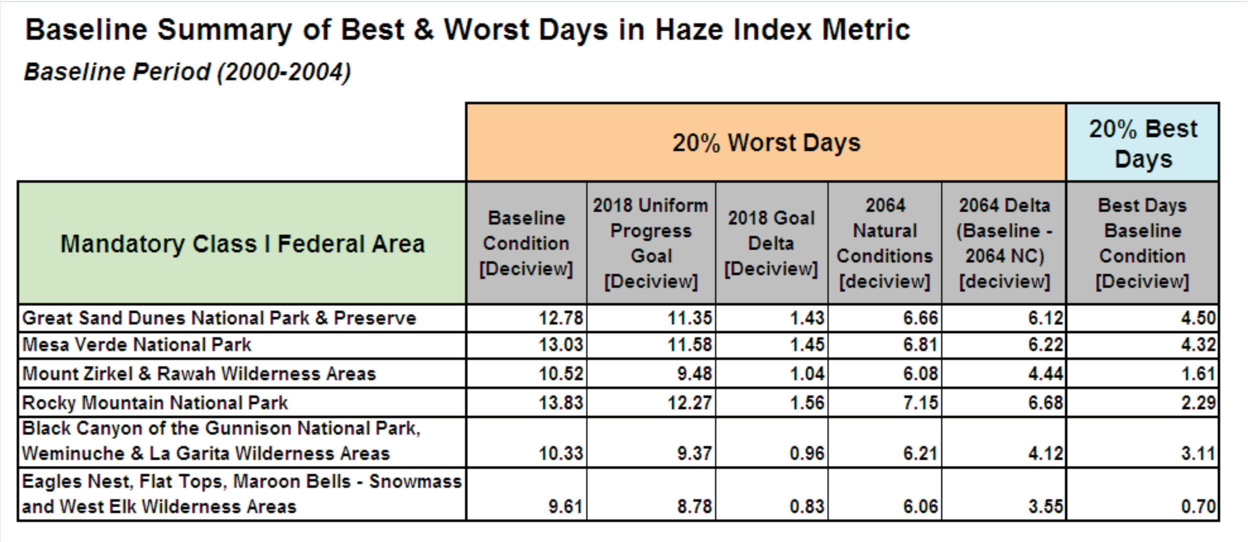
The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions.

More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado's twelve Class I areas. This calculation is consistent with EPA's *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Rule* (June 1, 2007).

For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day's baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area



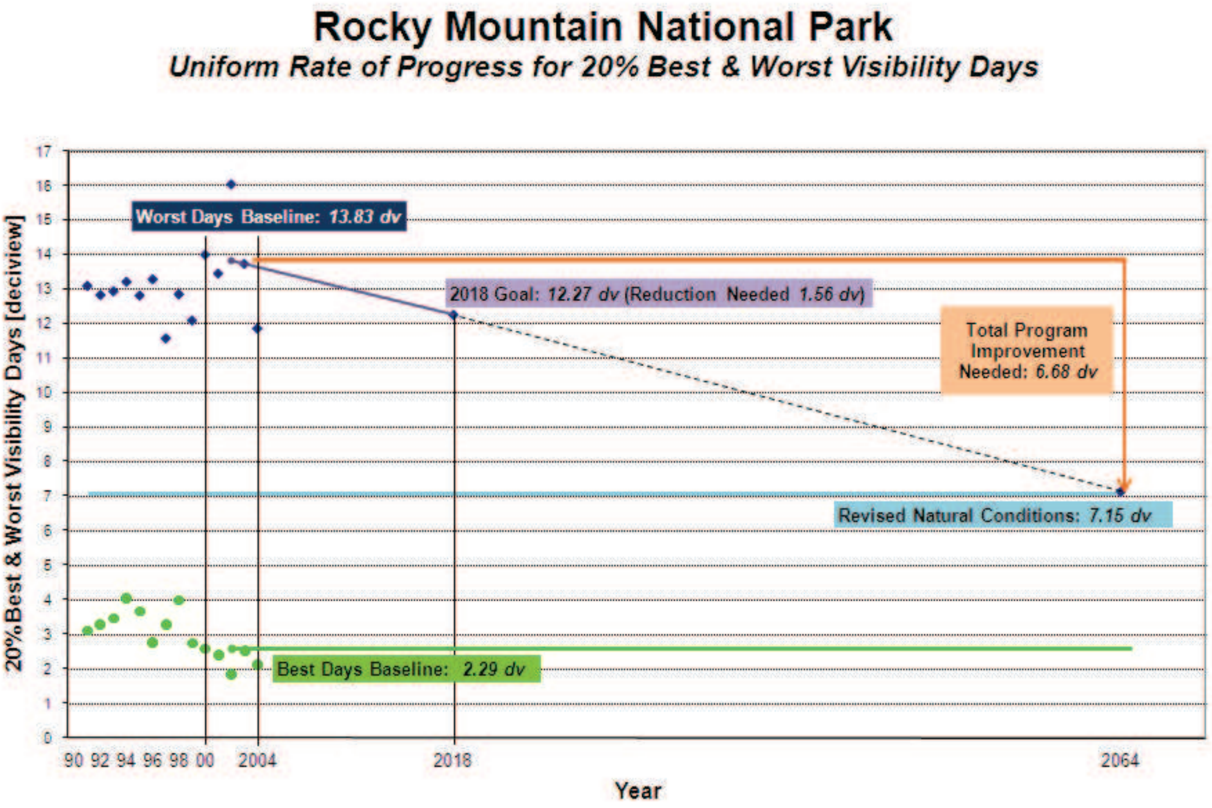
Baseline Summary of Best & Worst Days in Haze Index Metric

Baseline Period (2000-2004)

	20% Worst Days					20% Best Days
Mandatory Class I Federal Area	Baseline Condition [Deciview]	2018 Uniform Progress Goal [Deciview]	2018 Goal Delta [Deciview]	2064 Natural Conditions [deciview]	2064 Delta (Baseline - 2064 NC) [deciview]	Best Days Baseline Condition [Deciview]
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	6.66	6.12	4.50
Mesa Verde National Park	13.03	11.58	1.45	6.81	6.22	4.32
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	6.08	4.44	1.61
Rocky Mountain National Park	13.83	12.27	1.56	7.15	6.68	2.29
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	6.21	4.12	3.11
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	6.06	3.55	0.70

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best days baseline.

Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park



Chapter 5 Sources of Impairment in Colorado

5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado's regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days.

Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO2 & NOx and other secondary particulate forming pollutants such as VOC and NH3. Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM2.5), coarse particulate (PM-2.5 to PM-10), and ammonia (NH3). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

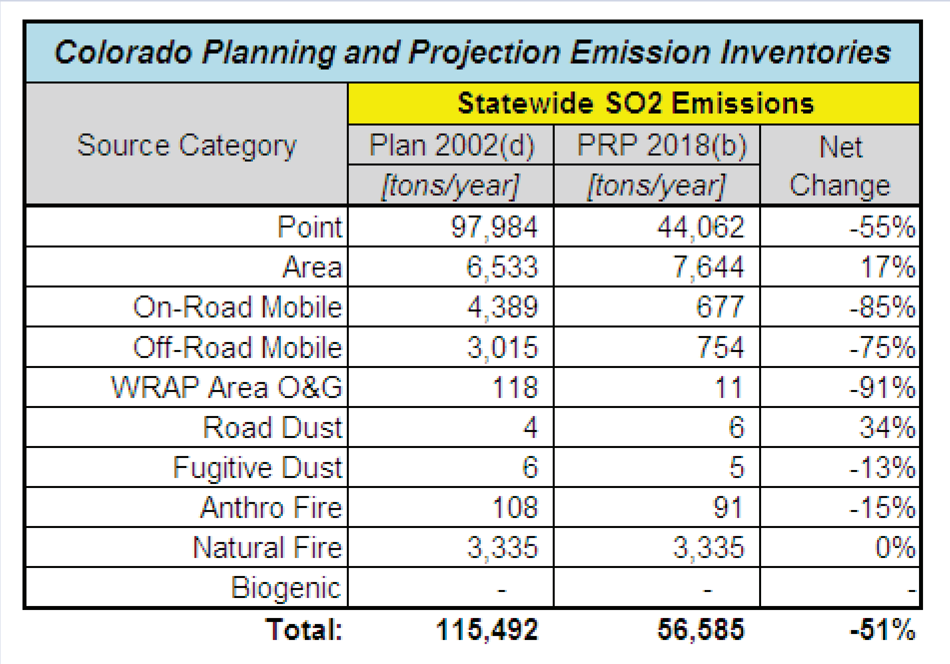
Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web site: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and a summary description of the inventory is found in the Emission Inventory TSD.

Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods. For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The “Plan 2002(d)” and “PRP 2018(b)” phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

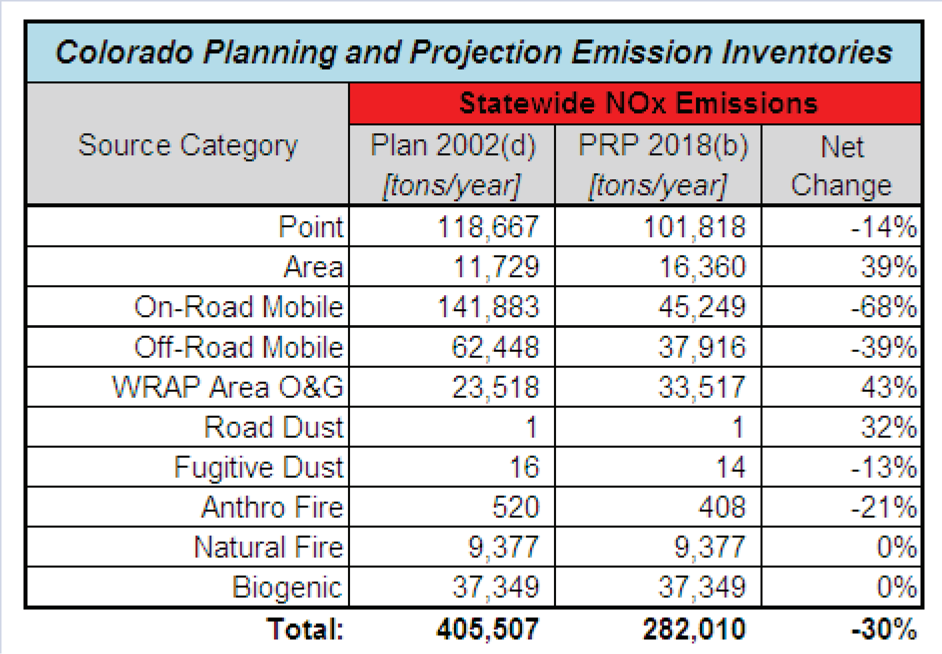
Figure 5-1 Colorado SO2 Emission Inventory – 2002 & 2018



Colorado Planning and Projection Emission Inventories			
	Statewide SO2 Emissions		
Source Category	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	97,984	44,062	-55%
Area	6,533	7,644	17%
On-Road Mobile	4,389	677	-85%
Off-Road Mobile	3,015	754	-75%
WRAP Area O&G	118	11	-91%
Road Dust	4	6	34%
Fugitive Dust	6	5	-13%
Anthro Fire	108	91	-15%
Natural Fire	3,335	3,335	0%
Biogenic	-	-	-
Total:	**115,492**	**56,585**	**-51%**

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO2 emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as ‘natural’ these represent only 3% of the statewide inventory. A 51% statewide reduction in SO2 emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

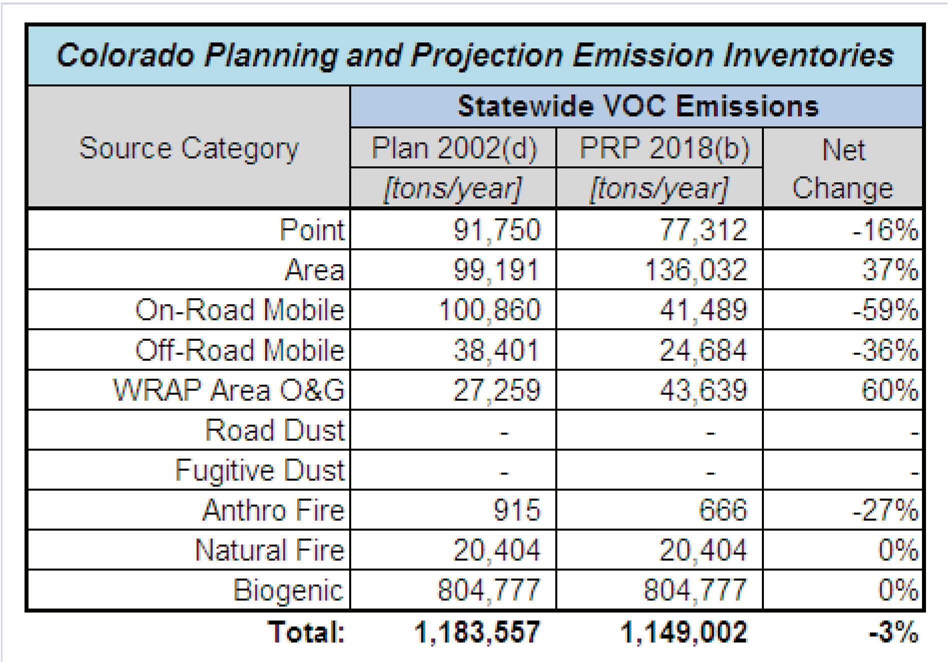
Figure 5-2 Colorado NO_x Emission Inventory – 2002 & 2018



Colorado Planning and Projection Emission Inventories			
Source Category	Statewide NOx Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	118,667	101,818	-14%
Area	11,729	16,360	39%
On-Road Mobile	141,883	45,249	-68%
Off-Road Mobile	62,448	37,916	-39%
WRAP Area O&G	23,518	33,517	43%
Road Dust	1	1	32%
Fugitive Dust	16	14	-13%
Anthro Fire	520	408	-21%
Natural Fire	9,377	9,377	0%
Biogenic	37,349	37,349	0%
Total:	**405,507**	**282,010**	**-30%**

Nitrogen oxides (NOx) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources. Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

Figure 5-3 Colorado VOC Emission Inventory – 2002 & 2018

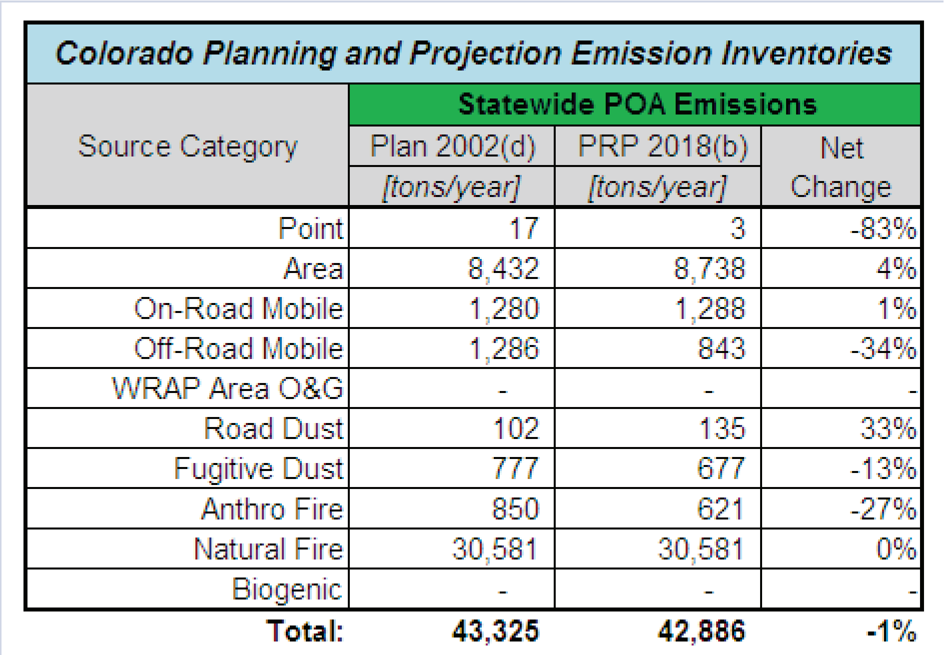


Colorado Planning and Projection Emission Inventories

Source Category	**Statewide VOC Emissions**		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	91,750	77,312	-16%
Area	99,191	136,032	37%
On-Road Mobile	100,860	41,489	-59%
Off-Road Mobile	38,401	24,684	-36%
WRAP Area O&G	27,259	43,639	60%
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	915	666	-27%
Natural Fire	20,404	20,404	0%
Biogenic	804,777	804,777	0%
Total:	**1,183,557**	**1,149,002**	**-3%**

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory – 2002 & 2018

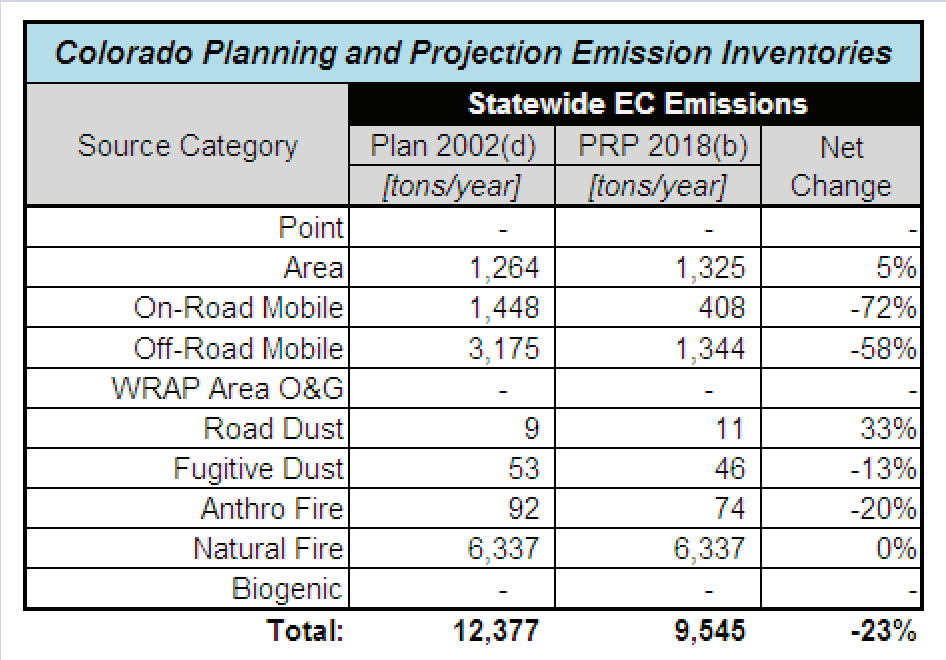


Colorado Planning and Projection Emission Inventories

Source Category	Statewide POA Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	17	3	-83%
Area	8,432	8,738	4%
On-Road Mobile	1,280	1,288	1%
Off-Road Mobile	1,286	843	-34%
WRAP Area O&G	-	-	-
Road Dust	102	135	33%
Fugitive Dust	777	677	-13%
Anthro Fire	850	621	-27%
Natural Fire	30,581	30,581	0%
Biogenic	-	-	-
Total:	**43,325**	**42,886**	**-1%**

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory – 2002 & 2018

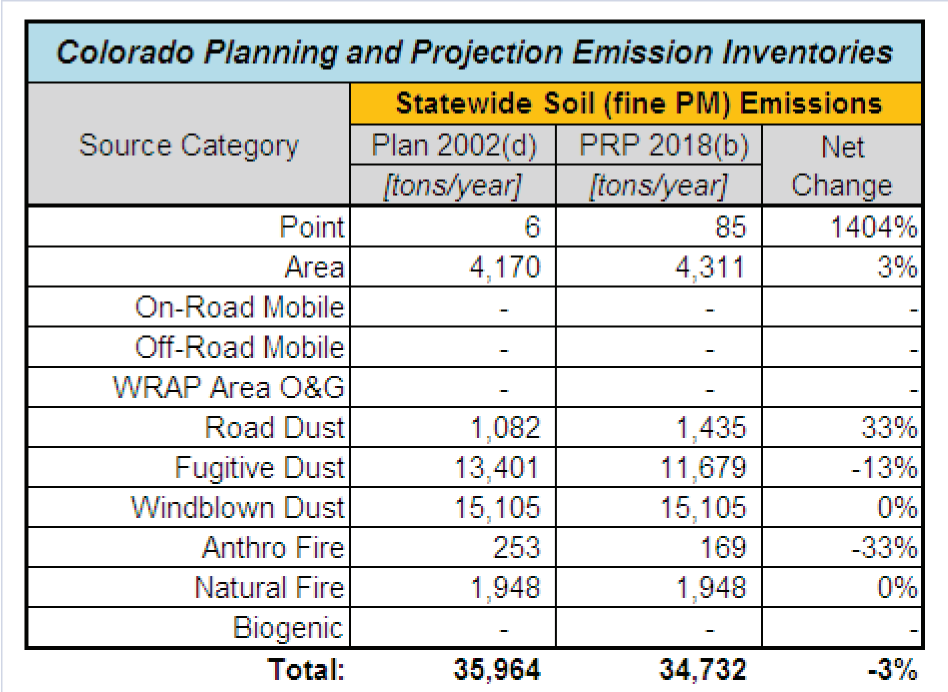


Colorado Planning and Projection Emission Inventories

Source Category	Statewide EC Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	-	-	-
Area	1,264	1,325	5%
On-Road Mobile	1,448	408	-72%
Off-Road Mobile	3,175	1,344	-58%
WRAP Area O&G	-	-	-
Road Dust	9	11	33%
Fugitive Dust	53	46	-13%
Anthro Fire	92	74	-20%
Natural Fire	6,337	6,337	0%
Biogenic	-	-	-
Total:	**12,377**	**9,545**	**-23%**

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

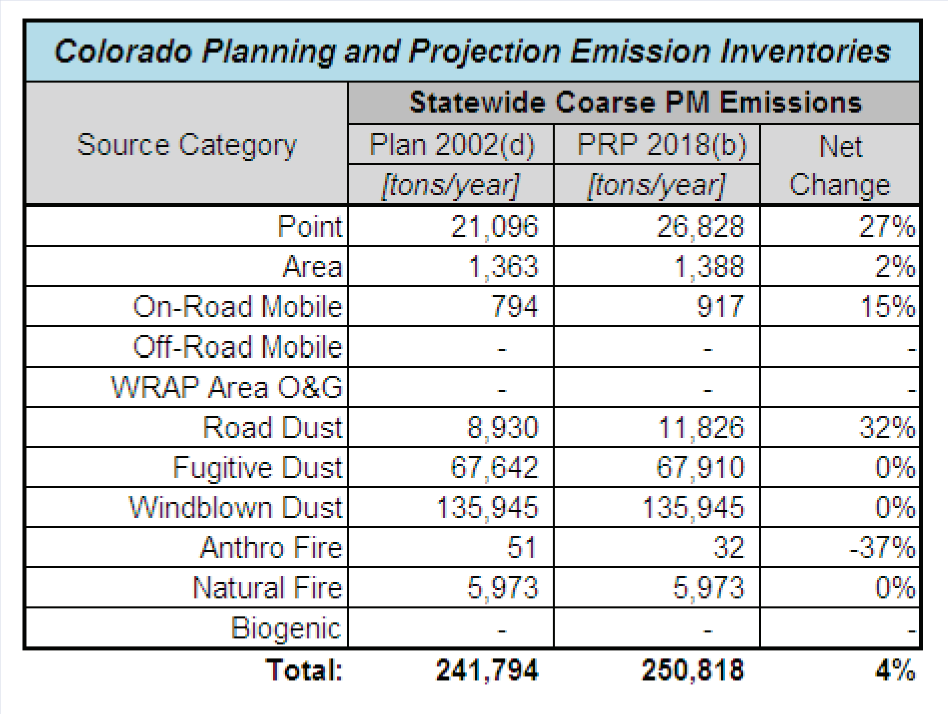
Figure 5-6 Colorado Soil (PM Fine) Emission Inventory – 2002 & 2018



Colorado Planning and Projection Emission Inventories			
	Statewide Soil (fine PM) Emissions		
Source Category	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	6	85	1404%
Area	4,170	4,311	3%
On-Road Mobile	-	-	-
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	1,082	1,435	33%
Fugitive Dust	13,401	11,679	-13%
Windblown Dust	15,105	15,105	0%
Anthro Fire	253	169	-33%
Natural Fire	1,948	1,948	0%
Biogenic	-	-	-
Total:	**35,964**	**34,732**	**-3%**

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory – 2002 & 2018

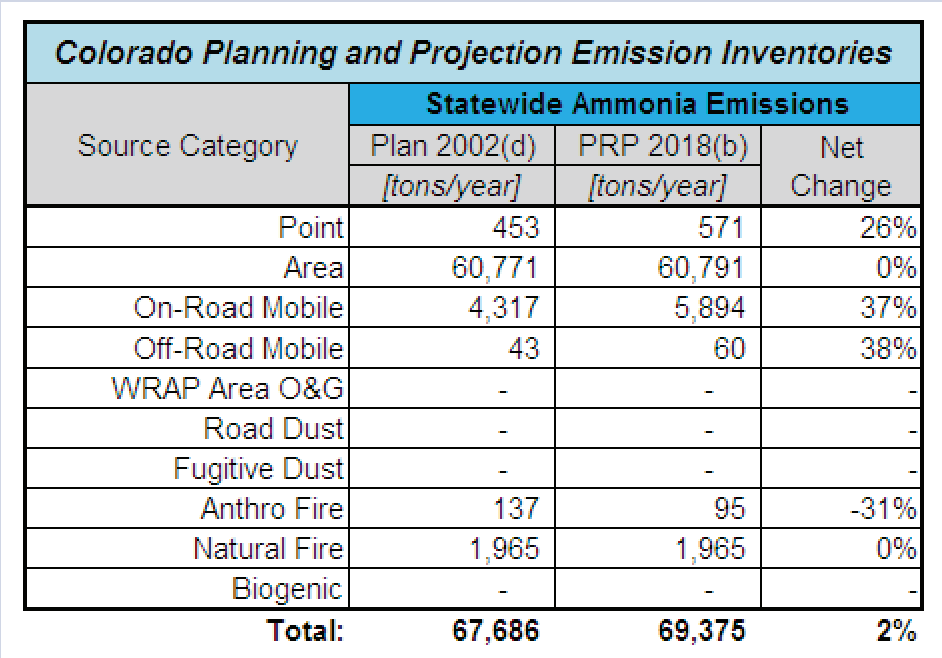


Colorado Planning and Projection Emission Inventories

Source Category	Statewide Coarse PM Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	21,096	26,828	27%
Area	1,363	1,388	2%
On-Road Mobile	794	917	15%
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	8,930	11,826	32%
Fugitive Dust	67,642	67,910	0%
Windblown Dust	135,945	135,945	0%
Anthro Fire	51	32	-37%
Natural Fire	5,973	5,973	0%
Biogenic	-	-	-
Total:	**241,794**	**250,818**	**4%**

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

Figure 5-8 Colorado Ammonia (NH3) Emission Inventory – 2002 & 2018



Colorado Planning and Projection Emission Inventories

Source Category	Statewide Ammonia Emissions Plan 2002(d) *[tons/year]*	Statewide Ammonia Emissions PRP 2018(b) *[tons/year]*	Statewide Ammonia Emissions Net Change
Point	453	571	26%
Area	60,771	60,791	0%
On-Road Mobile	4,317	5,894	37%
Off-Road Mobile	43	60	38%
WRAP Area O&G	-	-	-
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	137	95	-31%
Natural Fire	1,965	1,965	0%
Biogenic	-	-	-
Total:	**67,686**	**69,375**	**2%**

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

Chapter 6 Best Available Retrofit Technology

6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress' intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency's (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. *See* 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977.

Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state's visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA's Regional Haze Rule. Colorado's review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

6.2 Overview of Colorado's BART Regulation

Colorado's Air Quality Control Commission approved a State-only BART regulation (Regulation 3 Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out below, in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division's BART website at: http://www.cdphe.state.co.us/ap/RegionalHazeBART.html.

Colorado's BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO2, NOx and particulate matter.
2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being

subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98th percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

6.3 Summary of Colorado's BART Determinations

Colorado's Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1 below.

Table 6 - 1 Results of Subject-to-BART Modeling

Modeled BART–Eligible Source	Division Modeling (98th percentile delta-deciview value)	Division Approved Refined Modeling from Source Operator (98th percentile delta-deciview value)	Contribution Threshold (deciviews)	Impact Equal to or Greater Than Contribution Threshold?
CEMEX - Lyons Cement Kiln & Dryer	1.533		0.5	Yes
CENC (Trigen-Colorado) Units 4 & 5	1.255		0.5	Yes
Cherokee Station – Unit 4	1.460		0.5	Yes
Comanche Station – Units 1 and 2	0.701		0.5	Yes
Craig Station – Units 1 & 2	2.689		0.5	Yes
Hayden Station – Units 1 & 2	2.538		0.5	Yes
Lamar Light & Power – Unit 6	0.064		0.5	No
Martin Drake Power Plant – Units 5, 6 & 7	1.041		0.5	Yes
Pawnee Station – Unit 1	1.189		0.5	Yes
Ray D. Nixon Power Plant – Unit 1	0.570	0.481	0.5	No
Suncor Denver Refinery	0.239		0.5	No
Valmont Station – Unit 5	1.591		0.5	Yes

Notes:

1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model.
2. Source operator modeling results are shown only if modeling has been approved by Division.
3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment.
4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu).
5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction.
6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO2.
7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards.

Of the BART-eligible sources listed above, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO_2 Control Type	SO_2 Emission Limit	Assumed ** Particulate Control and Emission Limit
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO_2 Control Type	SO_2 Emission Limit	Assumed ** Particulate Control and Emission Limit
Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Non-Catalytic Reduction System	0.28 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources [5, 6, 7]

Emission Unit	NOx Control Type	NOx Emission Limit	SO_2 Control Type	SO_2 Emission Limit	Particulate Control and Emission Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation 12/31/2017	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (rolling 12 month average) 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

For all BART and BART alternative determinations, approved in the Federal State Implementation Plan, the state affirms that the BART emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional

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[5] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

[6] 500 tpy NOx will be reserved from Cherokee station for netting or offsets.

[7] 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

Haze analyses or Regional Haze controls will be required by the state during this timeframe.

6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA's proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990's, based on EPA's expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

6.4.1 The State's Consideration of BART Factors

In identifying a level of control as BART, States are required by section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and
(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado's BART regulation requires that the five statutory factors be considered for all BART sources. *See,* Regulation No. 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NOx controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state's facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

6.4.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO2 and NOx control equipment to upgrade analyses of existing SO2 controls. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix C.

6.4.1.2 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

6.4.1.3 Any existing pollution control technology in use at the source. The state has taken into consideration the existing PM, SO2 and NOx pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM" s*ee* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

6.4.1.4 The remaining useful life of the source. None of Colorado's BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state's BART determinations.

6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented below and in Appendix C.

6.4.2 SIP Requirements from EPA's Regional Haze Rule

The following section includes information addressing the SIP elements contained in EPA's Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

(i) A list of all BART-eligible sources within the State.

Table 6 - 3 below lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division's source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado's BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the "cause or contribute" thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Cemex - Lyons Kiln	Cemex	Portland Cement	<1977	Subject-to-BART
Cemex - Lyons Dryer	Cemex	Portland Cement	<1977	Subject-to-BART
CENC Unit 4	Colorado Energy Nations Company (CENC)	360 MMBtu/hr	1975	Subject-to-BART
CENC Unit 5	CENC	650 MMBtu/hr	1979	Subject-to-BART
Cherokee Unit 4	Public Service Company of Colorado (PSCO)	350 MW	1968	Subject-to-BART
Comanche Unit 1	PSCO	350 MW	1973	Subject-to-BART
Comanche Unit 2	PSCO	350 MW	1976	Subject-to-BART
Craig Unit 1	Tri-State Generation and	446 MW	1979	Subject-to-BART

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
	Transmission, Inc.			
Craig Unit 2	Tri-State	446 MW	1979	Subject-to-BART
Hayden Unit 1	PSCO	190 MW	1965	Subject-to-BART
Hayden Unit 2	PSCO	275 MW	1976	Subject-to-BART
Martin Drake Unit 5	Colorado Springs Utilities (CSU)	55 MW	1962	Subject-to-BART
Martin Drake Unit 6	CSU	85 MW	1968	Subject-to-BART
Martin Drake Unit 7	CSU	145 MW	1974	Subject-to-BART
Pawnee Unit 1	PSCO	500 MW	1981	BART Alternative
Valmont Unit 5	PSCO	188 MW	1964	Subject-to-BART
Denver Steam Unit 1	PSCO	Steam only 210 MMBtu/hr	1972	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Denver Steam Unit 2	PSCO	Steam only 243 MMBtu/hr	1974	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Holcim Kiln	Holcim	Portland Cement	<1977	Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions.
Lamar Utilities	City of Lamar	25 MW	1972	Plant will be shutdown; so will no longer be subject.
Oregon Steel	Oregon Steel	Steel Mfg.	<1977	Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions.
Ray Nixon Unit 1	CSU	227 MW	1980	Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact)
Roche	Roche	Pharmaceutical Mfg.	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO
Suncor/Valero	Suncor	Refinery	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO

(ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state's BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

(iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state's facility-specific consideration of the five factors and resulting determinations are provided in this chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

(iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association's Craig plant located in Moffat County. The Division's BART determination for the Craig facility is discussed in more detail below.

(v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado's BART Rule, and Regulation No. 3 Part F Section VI.

(vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation No. 3. Part F Section VII.

6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.[8] The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.[9]

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO2 and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on BART electric generating units, for reasons described below, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO2 emissions, there are currently ten lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[10] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.[11] The

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[8] The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. *See* 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. *See, e.g., id.* at 39108, 39131 and 39158.

[9] *See, e.g.*, 70 Fed. Reg. at 39170.

[10] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

[11] In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. *See* 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA's position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id. See also,* 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NOx Limits for Electric Generating Units* and *Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO2 Limits for Electric Generating Units*,

Division has determined in the past that these systems can be cost-effective for Colorado's BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities' Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado's BART-subject units.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.[12] In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement

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Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

[12] *See* 70 Fed. Reg. at 39170 and 39137.

expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[13] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[14] The $5,000/ton criterion is also consistent and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, has the ability to provide significant NOx reductions, but also has initial capital dollar requirements that can

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[13] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[14] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

approach or exceed $100 million per unit.[15] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[16] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[17] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

6.4.3.1 BART Determination for Cemex's Lyons Cement Plant

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex

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[15] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[16] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[17] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado's BART eligible sources became subject to BART. *See*, Air Quality Control Commission Regulation No. 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen.

Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98th percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98th percentile visibility impact from the kiln is 0.76 Δdv. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO2 emission limitation is 36.7 tpy and the BART NOx emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

SO2 BART Determination for Cemex Lyons - Kiln

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO2 emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Baseline SO2 Emissions		25.3	95.0	0.40
Lime Addition to Kiln Feed	25%	18.9	71.3	0.30
Fuel Substitution (coal with TDF)	40%	15.2	57.0	0.24

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Dry Sorbent Injection	50%	12.6	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
SO2 Control Technology	SO2 Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline SO2 Emissions	-			
Lime Addition to Kiln Feed	23.8	$3,640,178	$153,271	
Fuel Substitution (coal supplemented with TDF)	38.0	$172,179	$4,531	$243,368
Dry Sorbent Injection	47.5	Not provided	-	
Wet Lime Scrubbing (Tailpipe scrubber)	85.5	$2,529,018	$29,579	$49,618

The following table lists the projected visibility improvements for SO2 controls:

Cemex Lyons - Kiln		
SO2 Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max)	0.760	
Baseline (95 tpy)*	0.731	-
Lime Addition to Kiln Feed (71.3 tpy)*	0.727	0.033
Fuel Substitution (57 tpy)*	0.725	0.034
Dry Sorbent Injection (47.5 tpy)*	0.725	0.036
Wet Lime Scrubbing (9.5 tpy)*	0.720	0.040

** Visibility impacts rescaled from original BART modeling*

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO2 emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO2 emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO2 per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

SO2 BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO2 BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

NOx BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NOx burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NOx emissions from Portland cement kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes “available” control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

Cemex Lyons - Kiln				
NOx Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NOx Emissions (lbs/hr)	Annual Controlled NOx Emissions (tpy)	Annual Controlled NOx Emissions (lb/ton of Clinker)
Baseline NOx Emissions	-	464.3	1,747.1	7.39
Water Injection	7.0%	431.8	1,624.8	6.87
Coal w/TDF	10.0%	417.8	1,572.3	6.65
Indirect Firing with LNB	20.0%	371.4	1,397.6	5.91
SNCR (30-day rolling)	45.0%	255.3	960.9	4.06
SNCR (12-month rolling)	48.4%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex’s limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
NOx Control Technology	NOx Emission Reduction	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	($/yr)	($/ton)	($/ton)
Baseline NOx Emissions	-			
Water Injection	122.3	$43,598	$356	-
Coal w/TDF	174.7	$172,179	$986	$2,453
Indirect Firing with LNB	349.4	$710,750	$2,034	$3,083
SNCR (45.0% control)	786.2	$1,636,636	$2,082	$2,120
SNCR (48.4% control)	846.1	$1,636,636	$1,934	$1,864
SNCR w/LNB (55.0% control w/uncertainty)	960.9	$1,686,395	$1,755	$434

The following table lists the projected visibility improvements for NOx controls for the kiln:

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)
24-hr Maximum (≈ 656.9 lbs/hr))	0.760	
Revised Baseline (≈ 464.3 lbs/hr)*	0.572	0.188
Original Baseline (≈ 446.8 lbs/hr)*	0.555	0.205
Water Injection (≈ 431.8 lbs/hr)*	0.540	0.220
Firing TDF (≈417.9 lbs/hr)*	0.526	0.234
Indirect Firing with LNB (≈ 371.4 lbs/hr)*	0.481	0.279
Original BART Limit – SNCR (≈ 268.0 lbs/hr)	0.380	0.380
Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)**	0.368	0.392
Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)**	0.352	0.408
SNCR w/LNB (≈208.9 lbs/hr)**	0.322	0.438

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500°F) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for an effective NOx control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NOx are:

255.3 pounds per hour (30-day rolling average) and

901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NOx reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δdv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

NOx BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NOx BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009, as well as additional information upon the Division's request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

SO2 BART Determination for CENC - Boilers 4 and 5

Dry sorbent injection (DSI) and SO_2 emission management were determined to be technically feasible for reducing SO2 emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible. SO2 emissions management uses a variety of options to reduce SO2 emissions: dispatch natural gas-fired capacity, reduce total system load, and/or recue coal firing rate to maintain a new peak SO2 limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	1.0	$44,299	$43,690
DSI – Trona	468.0	$1,766,000	$3,774

CENC Boiler 5 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	0.8	$65,882	$78,095
DSI – Trona	844.0	$2,094,000	$2,482

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

SO2 Control Method	CENC - Boiler 4		CENC - Boiler 5	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.90		0.98	
DSI – Trona (annual avg.)	0.26	0.08	0.29	0.13

SO2 emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO2 reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)
CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

Particulate Matter BART Determination for CENC - Boilers 4 and 5

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM10) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for CENC - Boilers 4 and 5

Low NOx burners (LNB), LNB plus separated overfire air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 4 - NOx Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	0	$0
LNB	59.9	$193,433	$3,227
SNCR	179.8	$694,046	$3,860
LNB+SOFA	209.8	$678,305	$3,234
LNB+SOFA + SNCR	368.0	$1,372,351	$3,729
SCR	515.4	$4,201,038	$8,150

CENC Boiler 5 - NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	48.4	$249,858	$5,166
LNB+SOFA	127.3	$815,829	$6,383
SNCR	207.3	$923,996	$4,458
LNB+SOFA + SNCR	353.7	$1,739,825	$4,918
SCR	550.0	$6,469,610	$11,764

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- LNB + SOFA – may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	CENC - Boiler 4		CENC - Boiler 5	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx l Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.67		0.66	
LNB (annual avg.)	0.45	0.05	0.30	0.17
SNCR (annual avg.)	0.35	0.07	0.24	0.21
LNB + SOFA (annual avg.)	0.32	0.08	0.24	0.21
LNB + SOFA + SNCR (annual avg.)	0.19	0.12	0.17	0.26
SCR	0.07	0.18	0.07	0.31

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)
Or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air.
Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)
Or
0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed above in section 6.4.3.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8,

2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

SO2 BART Determination for Comanche - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO_2 removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.
- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO2 emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO2 removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Comanche – Unit 1		Comanche – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.75		0.74	
Semi-Dry FGD (LSD) (annual avg.)	0.12	0.35	0.12	0.33
Semi-Dry FGD (LSD) (annual avg.)	0.08	0.37	0.08	0.36

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO2 emission rates are BART:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

Particulate Matter BART Determination for Comanche - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/$PM_{10.}$ The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Comanche - Units 1 and 2

SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Comanche Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	445.6	$1,624,100	$3,644
SCR	770.4	$12,265,014	$15,290

Comanche Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SCR	1,480	$14,650,885	$9,900

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Comanche – Unit 1		Comanche – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (1-yr) using new LNBs	0.20		0.20	
SNCR (annual avg.)	0.10	0.11	Not Feasible	–
SCR (annual avg.)	0.07	0.14	0.07	0.17

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following existing NOx emission rates:

Comanche Unit 1:	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)
Comanche Unit 2:	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NOx burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Comanche Units 1 and 2 can be found in Appendix C.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* TriState determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
  1. Dibasic Acid (DBA) has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
  2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
    1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.
    2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
    3. A ventilation system was installed for each reaction tank.
    4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
    5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
    6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
    7. Instrumentation and controls were modified to support all of the new equipment.
- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 1		Craig – Unit 2	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1:	0.11 lb/MMBtu (30-day rolling average)
Craig Unit 2:	0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$3,797,000	$4,877
SCR	3,855	$25,036,709	$6,445

Craig Unit 2 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	806	$3,797,000	$4,712
SCR	3,975	$25,036,709	$6,299

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig – Unit 1		Craig – Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.07	0.98

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1:	0.27 lb/MMBtu (30-day rolling average)
Craig Unit 2:	0.27 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of SNCR. For the BART emission limits at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent NOx emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NOx emission rates are as follows:

Craig Unit 1:	0.28 lb/MMBtu (30-day rolling average)
Craig Unit 2:	0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu NOx emission rate equates to a 14% control and a NOx reduction of 727 tons per year, which is slightly less than the 15% control and a NOx reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NOx reduction of 3,975 tons per year, which is much greater than the 15% control and a NOx reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

The total NOx emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NOx emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NOx emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NOx rates, presumptive BART NOx rate, source-by-source determination, and the final RH determination to determine the total NOx reduction benefit. In the below table, the existing NOx emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NOx emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

NOx Analysis	Units	Craig 1	Craig 2	Total
Annual Average Heat Input*	*[MMBtu]*	36,933,572	39,214,982	
Annual Average NOx Rate*	*[lb/MMBtu]*	0.28	0.27	
Annual Average NOx Emissions*	*[tons/year]*	5,190.3	5,371.6	10,562
Presumptive NOx Rate	*[lb/MMBtu]*	0.39	0.39	
Presumptive NOx Emissions	*[tons/year]*	7,202.1	7,646.9	14,849
Source-by-Source Determination	*[lb/MMBtu]*	0.27	0.27	
Source-by-Source Determination	*[tons/year]*	4,411.8	4,565.9	8,978
Final Regional Haze Determination	*[lb/MMBtu]*	0.28	0.08	
Final Regional Haze Determination	*[tons/year]*	4,463.7	1,396.6	5,860

** Data from CAMD used for period (2006-2007)*

Based on the above analysis and demonstration, the BART Alternative (final RH determination) achieves more NOx emissions reductions, which are well below the source-by-source BART determinations for each unit. Consequently, the BART Alternative will result in more visibility improvement at nearby Class I areas, and the state adopts this BART Alternative as appropriate to comply with the Regional Haze rule for these units. The state notes that this BART Alternative is not a trading program per Section 308(e)(2) and provisions associated with trading are not applicable.

Under EPA's Alternative to BART rule (40 CFR § 51.308(e)(2)), a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration addresses these requirements, as follows. (A complete description of these federal requirements is presented in section 6.4.3.7 below.)

1) *51.308(e)(2)(i)(A)* A listing of all BART-eligible sources can be found in Table 6-3 above.
2) *51.308(e)(2)(i)(B)* The two BART-eligible sources are Craig Units 1 and 2.
3) *51.308(e)(2)(i)(C)* The BART determinations presented herein describe the control information and the projected total NOx reduction of 1,585 tons per year for source-by-source BART.
4) *51.308(e)(2)(i)(D)* The BART Alternative achieves a projected NOx reduction of 4,702 tons per year.
5) *51.308(e)(2)(i)(E)* The BART Alternative achieves more than 3,100 tons of projected NOx reduction per year over what would be achieved by the installation of BART.
6) *51.308(e)(2)(iii)* The Craig BART Alternative will be implemented as expeditiously as practicable but no later than five years after EPA's approval of this BART Alternative, as required by Regulation No. 3 Part F. The regulation requires that a compliance schedule be developed by the source and submitted to the state within six months from EPA's approval. The compliance and

monitoring provisions of the BART Alternative have also been incorporated into Regulation No. 3, Part F.

7) *51.308(e)(2)(iv)* The emission reductions associated with the Craig BART Alternative have not been used for other SIP purposes, thus they are surplus.

8) *51.308(e)(2)(v)* The state is not proposing a geographic enhancement for reasonably attributable impairment.

9) *51.308(e)(2)(vi)* Since Colorado is not using a trading program for the Craig BART Alternative, this section does not apply.

10) *51.308(e)(3)* There are only two units at the same facility under the Craig BART Alternative and thus there is no change in the distribution of emissions than under BART, and, as stated above, the alternative measure results in greater emission reductions than case-by-case BART. Therefore the Craig BART Alternative is deemed to achieve greater reasonable progress.

11) *51.308(e)(3)(i)* Since the Craig BART Alternative includes only two units at the same facility, the state has determined that visibility does not decline in any Class I area due to the Craig BART Alternative when compared to case-by-case BART.

12) *51.308(e)(3)(ii)* Because the Craig BART Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART, the state determines that there will be an overall improvement in visibility over all affected Class I areas.

13) *51.308(e)(4)* Colorado is not participating in the CAIR program and cannot rely on this program for the Craig BART Alternative.

14) The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

15) *51.308(e)(6)* No Colorado BART sources have applied for an exemption from BART.

A complete analysis that supports the BART determination and BART Alternative for Craig Station Units 1 and 2, including substantial cost information for NOx controls, can be found in Appendix C.

6.4.3.5 BART Determination for Public Service Company's Hayden Station

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

SO2 BART Determination for Hayden - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at Hayden Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO_2 removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO2 emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	61	$141,150	$2,317
Additional Scrubber Module	488	$4,142,538	$8,490

Hayden Unit 2 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	39	$141,150	$3,626
Additional Scrubber Module	589	$4,808,896	$8,164

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Hayden – Unit 1		Hayden – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.34		0.40	
Existing Semi-Dry FGD (LSD) (annual avg.)	0.16	0.09	0.16	0.18
Semi-Dry FGD Upgrade (annual avg.)	0.13	0.10	0.13	0.21
Additional Scrubber Module (annual avg.)	0.07	0.14	0.07	0.26

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)
Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

Particulate Matter BART Determination for Hayden - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,391	$572,010	$411
SNCR	1,391	$1,353,500	$973
SCR	3,120	$10,560,612	$3,385

Hayden Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,303	$992,729	$762
SNCR	1,610	$1,893,258	$1,176
SCR	3,032	$12,321,491	$4,064

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Hayden – Unit 1		Hayden – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.61		0.37	
LNB (annual avg.)	0.26	0.69	0.21	0.40
SNCR (annual avg.)	0.26	0.69	0.18	0.48
SCR (annual avg.)	0.07	1.12	0.06	0.85

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)
Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $3,385 per ton NOx removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton NOx removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NOx emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Hayden Units 1 and 2 can be found in Appendix C.

6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant

Colorado Springs Utilities' Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

SO2 BART Determination for Martin Drake - Units 5, 6 and 7

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO2 emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts. Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	762	$1,340,663	$1,760

Drake Unit 6 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	1,671	$2,910,287	$1,741
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	2,284	$6,186,854	$2,709
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	2,368	$6,647,835	$2,808
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	2,507	$7,452,788	$2,973

Drake Unit 7 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	2,657	$3,723,826	$1,405
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	3,632	$8,216,863	$2,263
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	3,764	$8,829,321	$2,345
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	3,986	$9,898,382	$2,483

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.94		1.00		0.99	
DSI (annual avg.)	0.25	0.12	0.33	0.18	0.33	0.29
Dry FGD (LSD) (annual avg.)	Not feasible		0.12	0.24	0.12	0.39
Dry FGD (LSD) (annual avg.)	Not feasible		0.07	0.26	0.07	0.41

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 5 is the following SO2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: $1,760 per ton SO2 removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 6 and Unit 7 is the following SO2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)
Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO2 removed; 0.39 deciview of improvement

Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Martin Drake - Units 5, 6 and 7

Ultra low NOx burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	154	$141,844	$923
Ultra-low NOx burners (ULNBs)	200	$147,000	$736
ULNBs + OFA	215	$288,844	$1,342
Selective Non-Catalytic Reduction (SNCR)	231	$1,011,324	$4,387
ULNB/SCR layered approach	626	$4,467,000	$7,133
Selective Catalytic Reduction (SCR)	626	$4,580,000	$7,314

Drake Unit 6 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	283	$104,951	$371
Selective Non-Catalytic Reduction (SNCR)	424	$1,208,302	$2,851
Ultra-low NOx burners (ULNBs)	452	$232,800	$515
ULNBs + OFA	509	$337,751	$664
ULNB/SCR layered approach	1,175	$6,182,800	$5,260
Selective Catalytic Reduction (SCR)	1,175	$6,340,000	$5,395

Drake Unit 7 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	416	$75,217	$181
Ultra-low NOx burners (ULNBs)	583	$386,000	$662
Selective Non-Catalytic Reduction (SNCR)	624	$2,018,575	$3,233
ULNBs + OFA	749	$461,217	$616
ULNB/SCR layered approach	1,709	$8,196,000	$4,797
Selective Catalytic Reduction (SCR)	1,709	$8,510,000	$4,981

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Drake – Unit 5 NOx Emission Rate (lb/MMBtu)	Drake – Unit 5 98th Percentile Impact (Δdv)	Drake – Unit 6 NOx Emission Rate (lb/MMBtu)	Drake – Unit 6 98th Percentile Impact (Δdv)	Drake – Unit 7 NOx Emission Rate (lb/MMBtu)	Drake – Unit 7 98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.62		0.83		0.71	
OFA (annual avg.)	0.30	0.07	0.33	0.18	0.31	0.22
ULNB (annual avg.)	0.28	0.08	0.28	0.193	0.28	0.24
ULNB + OFA (annual avg.)	0.27	0.08	0.27	0.20	0.25	0.26
SNCR (annual avg.)	0.27	0.08	0.29	0.19	0.28	0.24
ULNB + SCR	0.07	0.12	0.07	0.27	0.07	0.37
SCR (annual avg.)	0.07	0.12	0.07	0.27	0.07	0.37

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6:	0.31 lb/MMBtu (30-day rolling average)
Drake Unit 7:	0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: $616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described above (*e.g.* less than 0.50 Δdv)

For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6.

For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7.

A complete analysis that supports the BART determination for CSU's Martin Drake Units 5, 6 and 7 can be found in Appendix C.

6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative, which Includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3

Background

Section 308(e)(2) of EPA's Regional Haze Rule allows a state to approve a BART alternative:

> *A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.*

The PSCo BART Alternative Program (““PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air – Clean Jobs Act” (§ 40-3.2-201 C.R.S., *et. seq*.). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed below.

Table 6-5: Actions and Dates under the PSCo Alternative

Facility	Unit	Action or Control	Effective Date
Arapahoe	Unit 3	Shutdown	12/31/2013
	Unit 4	Operation on Natural Gas only (peaking unit)	12/31/2014
Cherokee	Unit 1	Shutdown	No later than 7/1/2012
	Unit 2	Shutdown	12/31/2011
	Unit 3	Shutdown	No later than 12/31/2016
	Unit 4	Operation on Natural Gas only	12/31/2017
Valmont		Shutdown	12/31/2017
Pawnee		SCR & LSD	12/31/2014

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

1) A list of all BART-eligible sources within the state;
2) A list of all BART-eligible sources and source categories covered by the alternative program;
3) An analysis of the best system of continuous emission control technology available and the associated reductions;
4) An analysis of the projected emissions reductions achievable through the alternative measure; and
5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a “peaking” unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state's alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state's analysis must include:

> *An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

40 CFR § 51.308(e)(2)(i)(C).

Colorado's alternative program was designed to meet a requirement other than BART; namely, Colorado's HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

> THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado's Clean Air – Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. *See,* § 40-3.2-204, C.R.S.

PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART. This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

> [T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also,* 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See,* 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

> In today's final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed above, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id*. at 60615 ("Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not

necessary to assure that the alternative program will result in greater reasonable progress than BART.”).

The PSCo BART Alternative includes only EGUs and, based on EPA’s Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id*. The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU’s of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state’s analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

Analysis Under 40 CFR Part 51, § 308(e)

(2)(i)(A) A list of all Bart-eligible sources within the State.

> A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.

> The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or section 308(e)(1), or otherwise be addressed under section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

Table 6-6: Sources Included Within the PSCo Alternative

Facility	Unit	Action or Control
Arapahoe	Unit 3	Shutdown
	Unit 4	Operation on natural gas only
Cherokee	Unit 1	Shutdown
	Unit 2	Shutdown
	Unit 3	Shutdown
	Unit 4 (BART-eligible)	Operation on natural gas only
	New nat. gas-fired EGU	BACT where netting does not apply
Valmont	(BART-eligible)	Shutdown
Pawnee	(BART-eligible)	SCR & LSD

(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

> The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq*.). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted above that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA's Alternative to BART Rule. *See,* 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.[18] The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.

> The emission reductions achievable through PSCo's Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo's emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8, below. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per

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[18] None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA's BART guidelines are not mandatory for these units. *See, e.g.,* 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

> year in the first planning period (2010 to 2018). With respect to NOx emissions, the PSCo BART Alternative will reduce NOx emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

> The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA's Alternative to BART Rule. This is explained in further detail below, and demonstrates that for both SO2 and NOx, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

(2)(ii) [Reserved]

(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO2 and NOx at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NOx emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future "netting" or "offsets". The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation No. 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation No. 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

> The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the

shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO2 or NOx from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Reg. No. 3, Part F.

(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

(3)(i) Visibility does not decline in any Class I area, and

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non–BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.

b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.

c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.

d) Pawnee Unit 1(BART eligible unit) will install and operate an LSD to control SO2 emissions and SCR to control NOx emissions in 2014.

(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs

Colorado is not participating in the CAIR program.

(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)–(h).

No Colorado BART sources have applied for an exemption from BART.

Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA's regional haze regulations. EPA's Regional Haze Rule requires that BART- eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative. EPA's BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA's regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA's BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. *See, e.g.,* 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO2 or a lb/MMBtu for NOx based on boiler and coal type. *See* 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule.").

As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC's actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe. For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA's regulation. Table 6-7 compares the tons of SO2 that would be emitted under the PSCo BART Alternative to the number of tons of SO2 that would be emitted by the same units if the standard of 0.15 lb SO2/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO2 removal, or an emission rate of 0.15 lb SO2/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO2/MMBtu was used for the alternative.

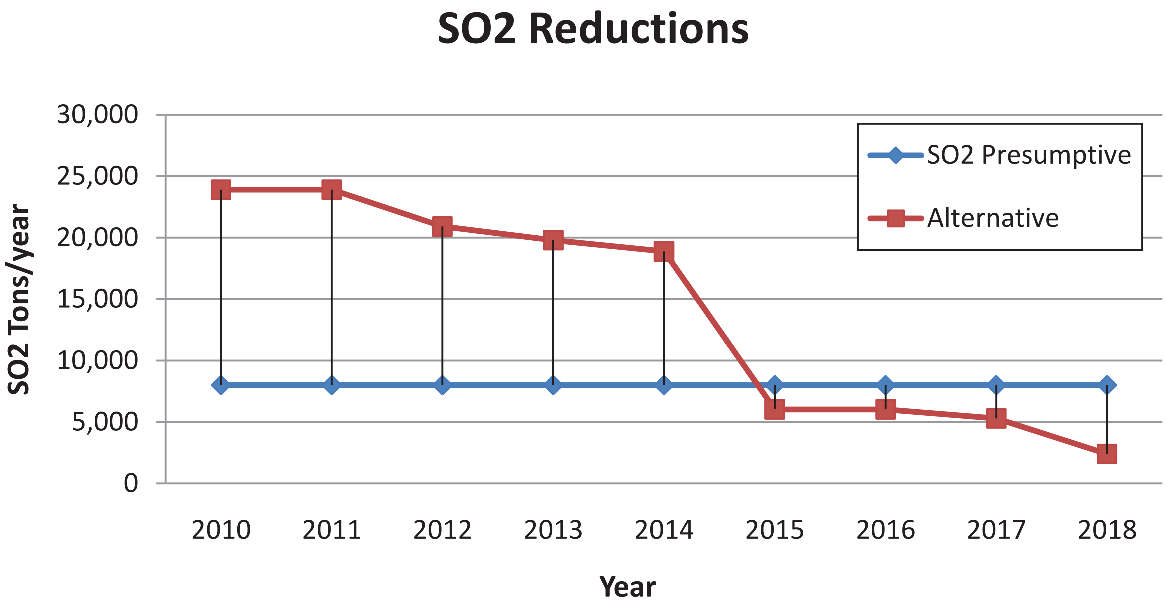
Table 6-7: SO2 Reductions Beyond Presumptive BART for PSCo Alternative

Facility	MMBtu Average 2006 to 2008	SO2 TPY Average 2006 to 2008	SO2 TPY at 0.15 lb/MMBtu Presumptive	SO2 TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28[19]	99.8%
Cherokee					
Unit 1	8,311,352	2,220.80	623.35	0.00	100.00%
Unit 2	5,586,021	1,888.37	418.95	0.00	100.00%
Unit 3	8,159,889	743.00	611.99	0.00	100.00%
Unit 4	26,047,648	2,135.43	1,953.57	7.81	99.6 %
Valmont	13,722,507	758.47	1,029.19	0.00	100.00%
Pawnee	40,093,753	13,472.07	3,007.03	2,405.63	20.00%
Total	114,847,083	23,908	8,614	2,415	71.97%

The comparison with the standard of 0.15 lb SO2/MMBtu shows that the PSCo BART Alternative provides 72% lower SO2 emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO2/MMBtu standard for this planning period.

Figure 6-1: SO2 reductions beyond presumptive BART for PSCo Alternative



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[19] Emission factor of 0.0006 lb SO2/MMBtu and 50% capacity factor.

A similar analysis was completed for NOx emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NOx limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NOx lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NOx emitted from Arapahoe 4 operating on natural gas as a "peaking" unit, 300 tpy of NOx reserved for "netting" or "offsets" from the Arapahoe facility, and 500 tpy of NOx reserved for "netting" or "offsets" from the Cherokee facility.

Table 6-8: NOx Reductions Beyond Presumptive BART for PSCo Alternative

Facility	MMBtu Average 2006 to 2008	NOx TPY Average 2006 to 2008	NOx lb/MMBtu Standard	TPY NOx at Standard	TPY NOx Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00[20]	8.42%
Cherokee						
Unit 1	8,311,352	1,556.23	0.39	1,620.71	0.00	100.00%
Unit 2	5,586,021	2,895.20	0.39	1,089.27	0.00	100.00%
Unit 3	8,159,889	1,865.50	0.39	1,591.18	0.00	100.00%
Unit 4	26,047,648	4,274.00	0.28	3,646.67	2,062.86[21]	43.43%
Valmont	13,722,507	2,313.73	0.28	1,921.15	0.00	100.00%
Pawnee	40,093,753	4,537.73	0.23	4,610.78	1,403.28	69.57%
Total	114,847,083	20,361		15,966	4,366	72.65%

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

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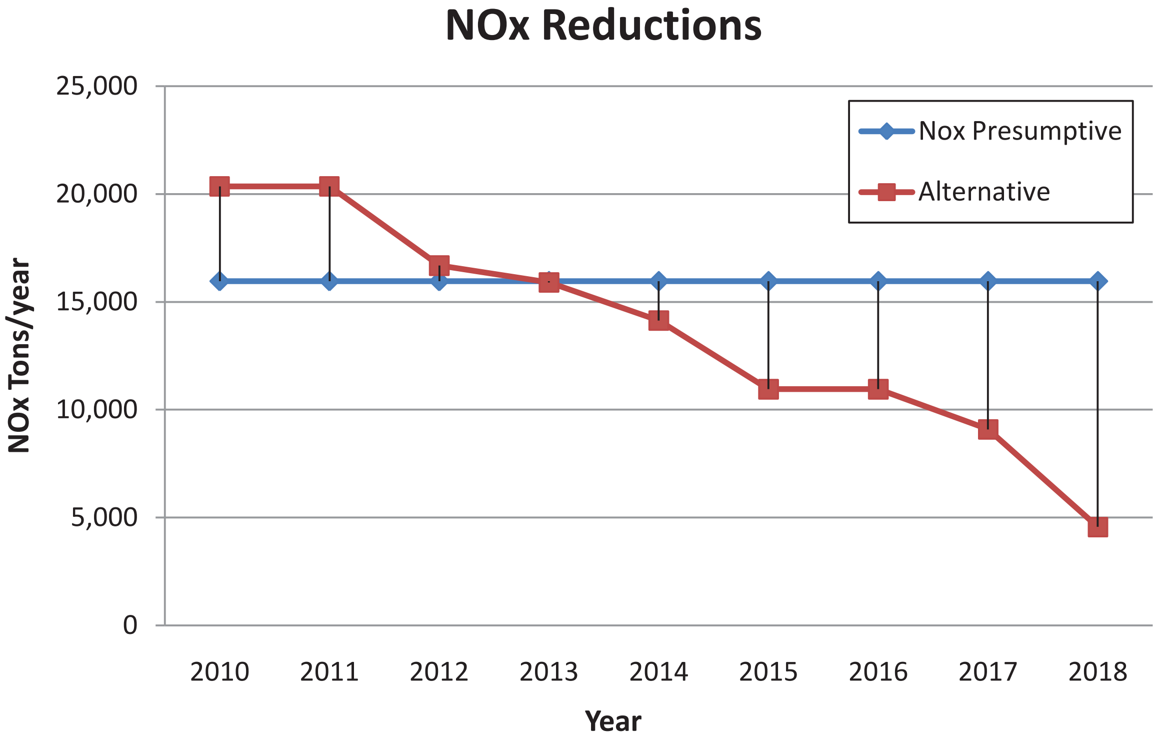
[20] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation. The 300 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with either unit.

[21] Cherokee 4 operating on natural gas at 0.12 lb NOx/mmBTU and 500tpy NOx reserved for "netting" or "offsets". The 500 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

Figure 6-2: NOx Reductions Beyond Presumptive BART for PSCo Alternative



The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO2 from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO2 and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO2 reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. *See* 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA's BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NOx reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NOx reductions. As part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than $5,000 per ton of NOx removed or the visibility improvement from SCR is less than 0.50 Δdv. See analysis in appendix C. Under the state's criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress. Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR. The division used study of SNCR on coal fired boilers in the size range of those in the PSCO BART Alternative. The study showed that the SNCR tested achieved a 35% reduction in NOx with less than 2ppm NH3 slip and 54% reduction with a 10ppm NH4 slip.[22] Because of the high ammonia slip at the higher range of NOx removal the division determined that 50% removal was appropriate for this comparison. Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NOx reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NOx.[23] Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

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[22] Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

[23] This level of NOx control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NOx reduction performance from application of SNCR.

Table 6-9: NOx reductions beyond state criteria for PSCo Alternative

Facility	SCR $/ton	SNCR $/ton	SNCR TPY at 50%[24]	PSCo Alternative TPY	% Reduction from SNCR at 50% Control
Arapahoe					
Unit 3			885.23	0	100.00%
Unit 4			573.83	900[25]	-56.84%
Cherokee					
Unit 1	N/A	$8,737	778.12	0	100.00%
Unit 2	N/A	$3,963	1,447.60	0	100.00%
Unit 3	$10,134	$3,485	932.75	0	100.00%
Unit 4	$6,252	$2,625	2,137.00	2,062[26]	3.47%
Valmont	$8,647	$3,328	1,156.87	0	100.00%
Pawnee	$4,371	$3,082	2,268.87	1,403	38.15%
Total			10,180	4,366	57.11%

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.[27] The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions

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[24] Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

[25] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NOx reserved for “netting” and “offsets” for additional natural gas generation.

[26] Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for “netting” or “offsets”.

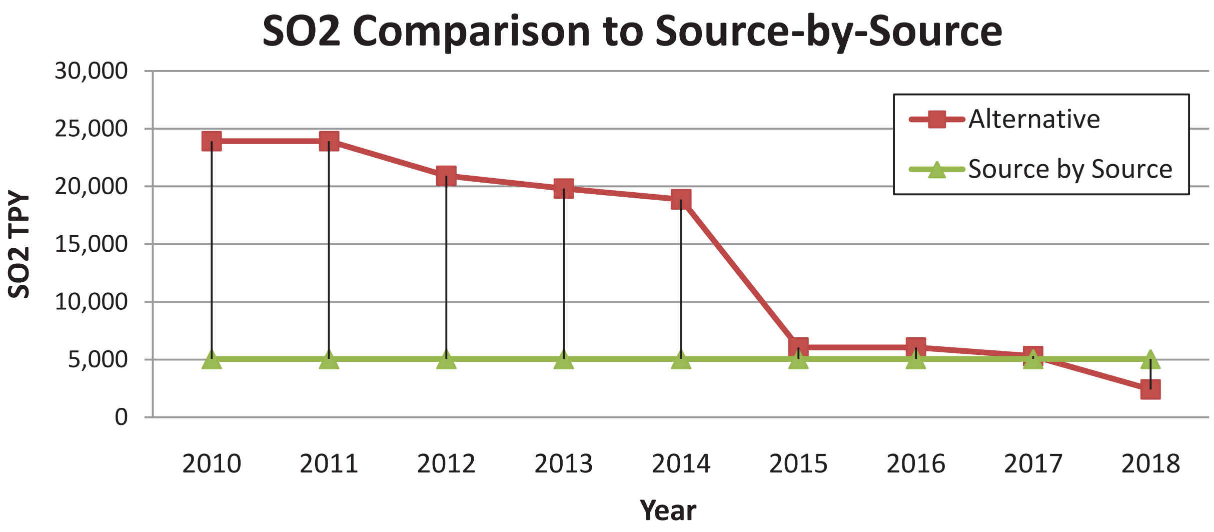
[27] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO2.

from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

Table 6-10: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	SO2 TPY from AP-42	Source-by-Source	SO2 TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	0.00	100.00%
Unit 4	9,779.27	1,953.57[28]	7.81	99.6%
Valmont	3,822.73	191.13	0.00	100.00%
Pawnee	8,342.36	2,405.62[29]	2,405.63	0.00%
Total	34,248	5,051	2,415	52.19%

Figure 6-3: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative



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[28] The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

[29] The Pawnee BART evaluation concluded that a 0.12 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[30] The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NOx for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NOx from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

Table 6-11: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	NOx TPY from AP-42	Source-by-Source	NOx TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	2,149.15	214.91	0.00	100.00%
Unit 4	4,636.00	600	900.00[31]	-50.00%
Cherokee				
Unit 1	3,596.54	359.65	0.00	100.00%
Unit 2	3,415.03	341.50	0.00	100.00%
Unit 3	4,411.28	441.12	0.00	100.00%
Unit 4	7,878.04	2,735.00[32]	2,062.86[33]	24.58%
Valmont	2,061.04	206.10	0.00	100.00%
Pawnee	7,945.11	3,608.43	1,403.28	61.11%
Total	36,092	8,507	4,366	48.67%

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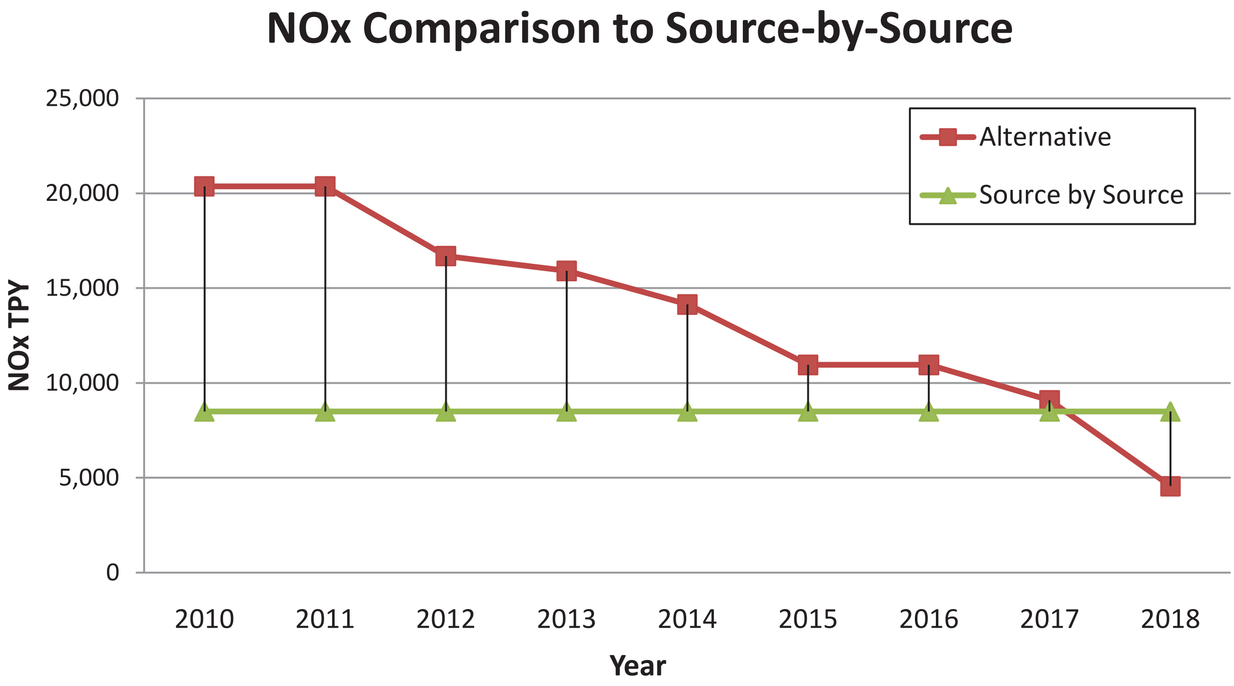
[30] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

[31] Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

[32] Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

[33] Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

Figure 6-4: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative



Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

Table 6-12: PSCo Alternative Emissions Limits[34, 35, 36]

Unit	NOx Control Type	NOx Emission Limit	SO2 Control Type	SO2 Emission Limit	Particulate Type And Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (12 month rolling average) by 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

[34] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

[35] 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

[36] 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado's 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

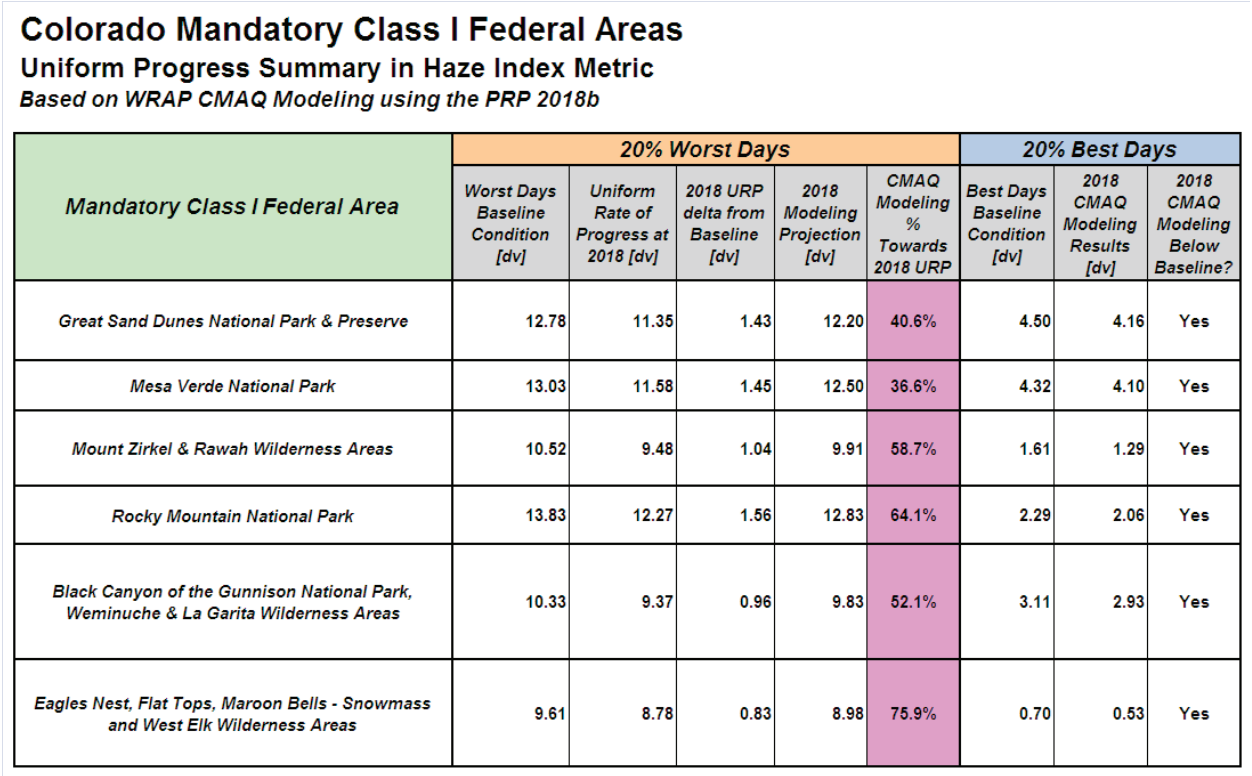
7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018.

More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP



Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*					*20% Best Days*		
	Worst Days Baseline Condition [dv]	*Uniform Rate of Progress at 2018 [dv]*	*2018 URP delta from Baseline [dv]*	*2018 Modeling Projection [dv]*	*CMAQ Modeling % Towards 2018 URP*	*Best Days Baseline Condition [dv]*	*2018 CMAQ Modeling Results [dv]*	*2018 CMAQ Modeling Below Baseline?*
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California – Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or “tags” to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged.

The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

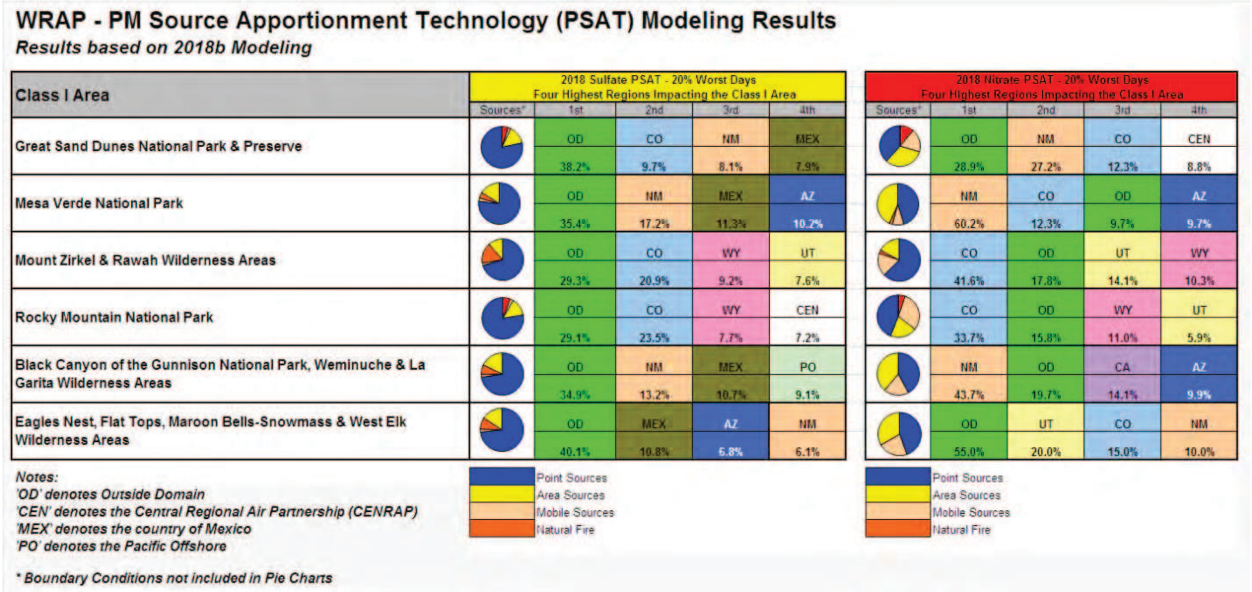
More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas. The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO2.

For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

Figure 7-2 Summary of PSAT Modeling for 2018



WRAP - PM Source Apportionment Technology (PSAT) Modeling Results

Results based on 2018b Modeling

Class I Area	2018 Sulfate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area					2018 Nitrate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area				
	Sources*	1st	2nd	3rd	4th	Sources*	1st	2nd	3rd	4th
Great Sand Dunes National Park & Preserve		OD 38.2%	CO 9.7%	NM 8.1%	MEX 7.9%		OD 28.9%	NM 27.2%	CO 12.3%	CEN 8.8%
Mesa Verde National Park		OD 35.4%	NM 17.2%	MEX 11.3%	AZ 10.2%		NM 60.2%	CO 12.3%	OD 9.7%	AZ 9.7%
Mount Zirkel & Rawah Wilderness Areas		OD 29.3%	CO 20.9%	WY 9.2%	UT 7.6%		CO 41.6%	OD 17.8%	UT 14.1%	WY 10.3%
Rocky Mountain National Park		OD 29.1%	CO 23.5%	WY 7.7%	CEN 7.2%		CO 33.7%	OD 15.8%	WY 11.0%	UT 5.9%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas		OD 34.9%	NM 13.2%	MEX 10.7%	PO 9.1%		NM 43.7%	OD 19.7%	CA 14.1%	AZ 9.9%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas		OD 40.1%	MEX 10.8%	AZ 6.8%	NM 6.1%		OD 55.0%	UT 20.0%	CO 15.0%	NM 10.0%

Notes:
'OD' denotes Outside Domain
'CEN' denotes the Central Regional Air Partnership (CENRAP)
'MEX' denotes the country of Mexico
'PO' denotes the Pacific Offshore

Point Sources
Area Sources
Mobile Sources
Natural Fire

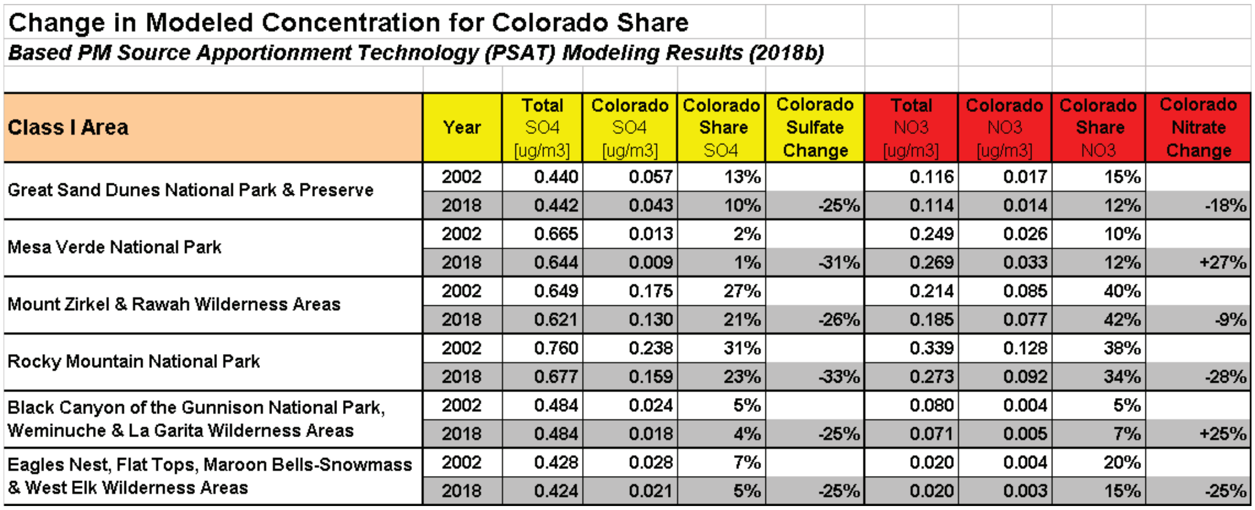
Point Sources
Area Sources
Mobile Sources
Natural Fire

** Boundary Conditions not included in Pie Charts*

Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado's and the region's NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018



Change in Modeled Concentration for Colorado Share

Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)

Class I Area	Year	Total SO4 [ug/m3]	Colorado SO4 [ug/m3]	Colorado Share SO4	Colorado Sulfate Change	Total NO3 [ug/m3]	Colorado NO3 [ug/m3]	Colorado Share NO3	Colorado Nitrate Change
Great Sand Dunes National Park & Preserve	2002	0.440	0.057	13%		0.116	0.017	15%	
	2018	0.442	0.043	10%	-25%	0.114	0.014	12%	-18%
Mesa Verde National Park	2002	0.665	0.013	2%		0.249	0.026	10%	
	2018	0.644	0.009	1%	-31%	0.269	0.033	12%	+27%
Mount Zirkel & Rawah Wilderness Areas	2002	0.649	0.175	27%		0.214	0.085	40%	
	2018	0.621	0.130	21%	-26%	0.185	0.077	42%	-9%
Rocky Mountain National Park	2002	0.760	0.238	31%		0.339	0.128	38%	
	2018	0.677	0.159	23%	-33%	0.273	0.092	34%	-28%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	2002	0.484	0.024	5%		0.080	0.004	5%	
	2018	0.484	0.018	4%	-25%	0.071	0.005	7%	+25%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas	2002	0.428	0.028	7%		0.020	0.004	20%	
	2018	0.424	0.021	5%	-25%	0.020	0.003	15%	-25%

Chapter 8 Reasonable Progress

8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state's alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, "Long Term Strategy". The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented below.

8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[37] of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado's 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO2 (sulfate precursor), NOx (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or "point" sources, dominate the emission inventories and apportionment modeling. This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total

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[37] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

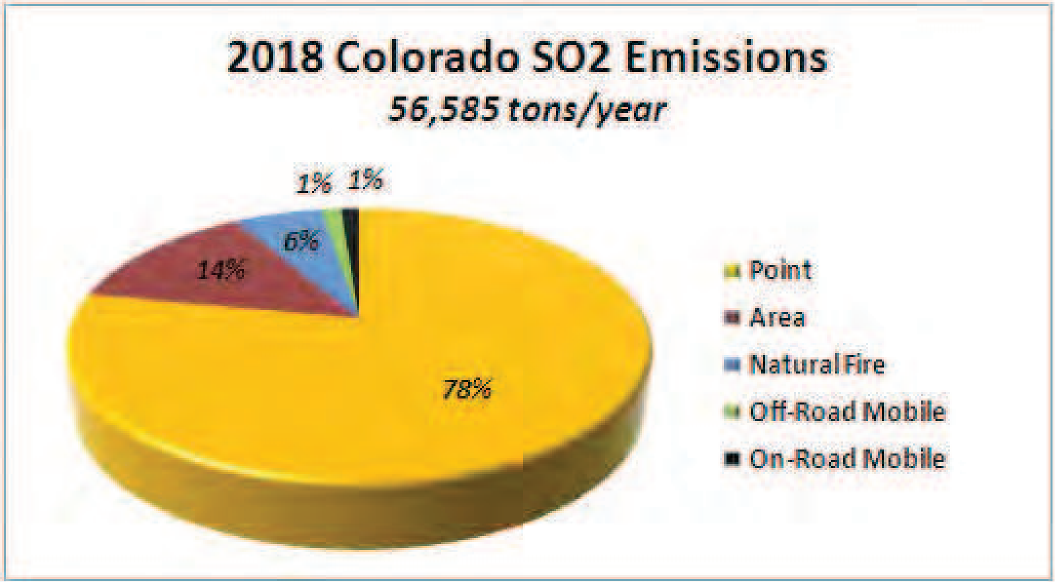
SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in section 8.2 above.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO2 emissions, which reflects "on-the-books (OTB)" and "on-the-way (OTW)" emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

Figure 8-1: Relative Source Contributions to Colorado SO2 Emissions in 2018

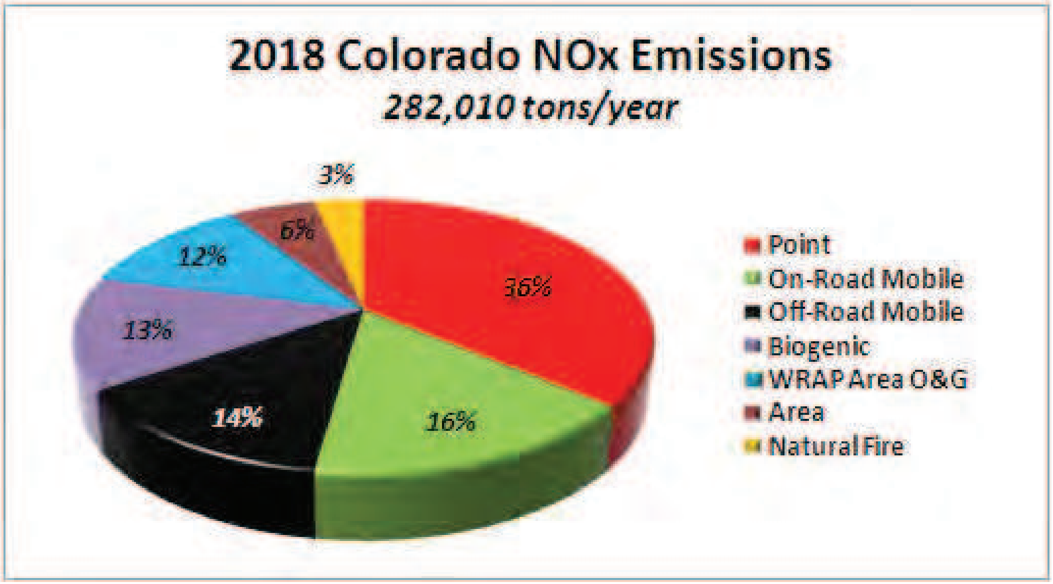


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO2 emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO2.

Figure 8-2 provides the statewide projected 2018 NOx emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

Figure 8-2: Relative Source Contributions to Colorado NOx Emissions in 2018



Point sources comprise 36% of total NOx emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NOx emissions respectively. A portion of the on-road mobile source NOx emissions reflect some level of NOx control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period. NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period.

The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado's Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

8.3.1 Oil and Gas Heater Treaters

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

8.3.2 Reciprocating Internal Combustion Engines

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides (NO_x; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). NO_x are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NOx emissions by design, and lean burn engines are designed to have relatively lower NOx emissions.

Colorado has undertaken regulatory initiatives to control NOx emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation No. 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NOx (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed $5,000 per ton. Selective catalytic reduction was considered for the control of NOx from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately $22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation No. 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described in the paragraph above, with the one exception that the $5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NOx emissions and is codified in Regulation No. 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NOx control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NOx control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado's emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NOx. At an average of about 10 tons of NOx emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NOx reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NOx per year from RICE of all sizes in Colorado. The NOx control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE

NOx emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NOx emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NOx assumed growth in uncontrolled engines and did not account for th NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NOx from engines is attributed to existing lean burn engines which are uncontrolled for NOx (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ.

A detailed 4-factor analysis for RICE can be found in Appendix D.

8.3.3 Combustion Turbines

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see section 8.3 below for a description of this "significance" determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are five Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- NO_x – 40 tons per year
- SO_2 – 40 tons per year
- PM_{10} – 15 tons per year

Facility – Turbine	Total 2006 – 2008 Averaged NOx Annual Emissions (tpy)	Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy)	Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy)	Greater than *de minimis* levels?
Front Range Power Plant – Turbine #1	159.6	2.9	4.9	Yes – NOx only
Front Range Power Plant – Turbine #2	147.9	2.8	4.9	Yes – NOx only

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NOx combustion systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions, respectively.

There is one feasible emission control technology available for these turbines is adding post combustion technology – selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 – 90 percent from uncontrolled levels.

Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NOx reduced annually with a capital expenditure of at least $15 million. The state estimates that SCR for these turbines will range from approximately $57,000 - $62,000 per ton of NOx reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NOx reductions are not cost-effective. The state has determined that NOx RP for combustion turbines is existing controls and emission limits.

A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control[38]. This RP screening methodology involves a calculated ratio called "Q-over-d", that evaluates stationary source emissions (mathematical sum of actual SO2, NOx and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area.

The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than "20" approximated a delta deciview (Δdv) impact ranging from 0.06 Δdv to 0.56 Δdv. The resultant average of the range is about 0.3 Δdv, which is a more conservative RP threshold than the 0.5 Δdv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF

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[38] *Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas,* March 31, 2010. See the Technical Support Document

modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM-10) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as "significant" sources for purposes of reasonable progress.

Figure 8-3: Point Sources with >100 TPY of Emissions

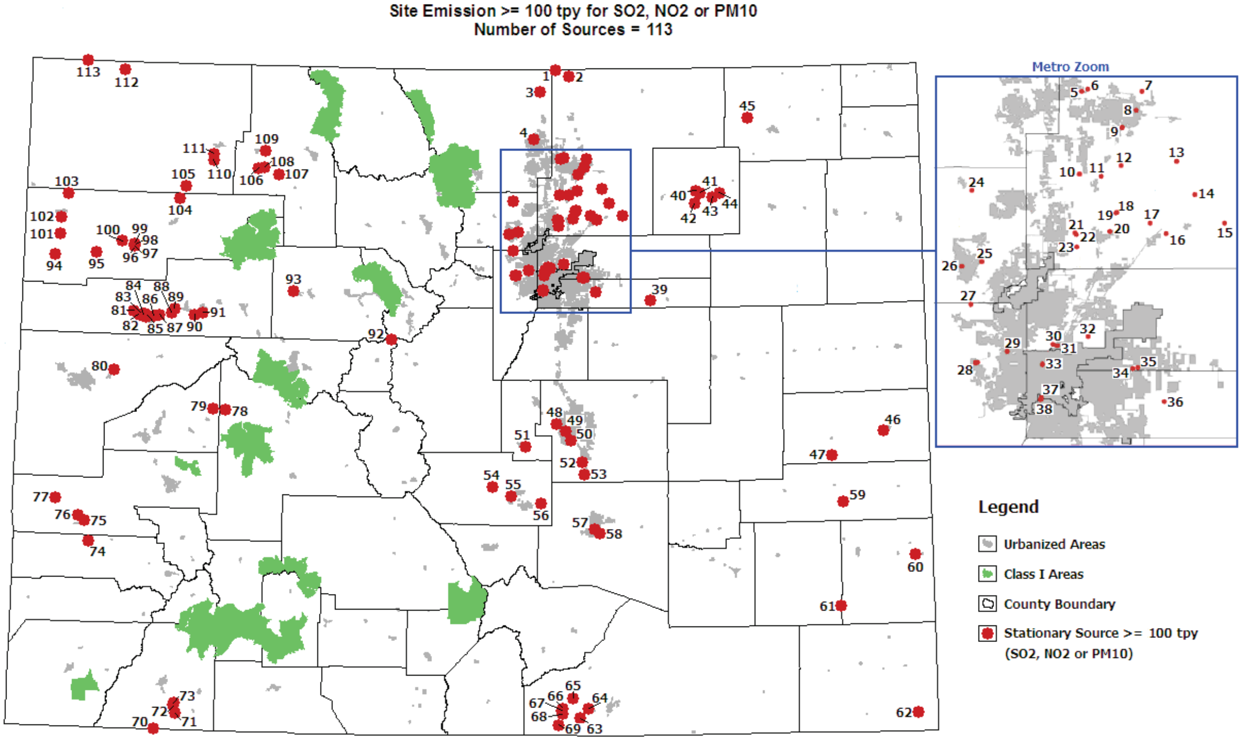
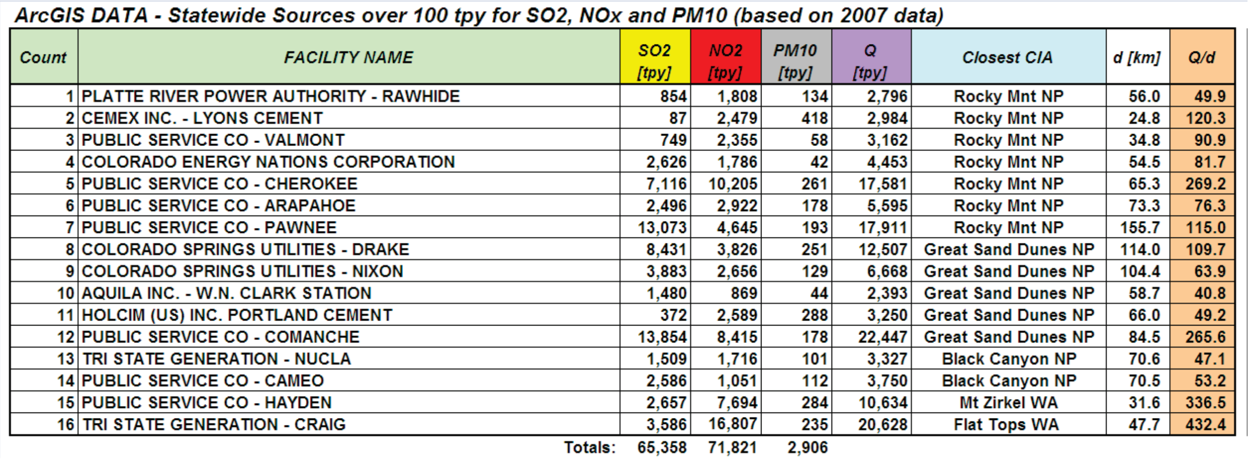


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20



ArcGIS DATA - Statewide Sources over 100 tpy for SO2, NOx and PM10 (based on 2007 data)

Count	FACILITY NAME	SO2 [tpy]	NO2 [tpy]	PM10 [tpy]	Q [tpy]	Closest CIA	d [km]	Q/d
1	PLATTE RIVER POWER AUTHORITY - RAWHIDE	854	1,808	134	2,796	Rocky Mnt NP	56.0	49.9
2	CEMEX INC. - LYONS CEMENT	87	2,479	418	2,984	Rocky Mnt NP	24.8	120.3
3	PUBLIC SERVICE CO - VALMONT	749	2,355	58	3,162	Rocky Mnt NP	34.8	90.9
4	COLORADO ENERGY NATIONS CORPORATION	2,626	1,786	42	4,453	Rocky Mnt NP	54.5	81.7
5	PUBLIC SERVICE CO - CHEROKEE	7,116	10,205	261	17,581	Rocky Mnt NP	65.3	269.2
6	PUBLIC SERVICE CO - ARAPAHOE	2,496	2,922	178	5,595	Rocky Mnt NP	73.3	76.3
7	PUBLIC SERVICE CO - PAWNEE	13,073	4,645	193	17,911	Rocky Mnt NP	155.7	115.0
8	COLORADO SPRINGS UTILITIES - DRAKE	8,431	3,826	251	12,507	Great Sand Dunes NP	114.0	109.7
9	COLORADO SPRINGS UTILITIES - NIXON	3,883	2,656	129	6,668	Great Sand Dunes NP	104.4	63.9
10	AQUILA INC. - W.N. CLARK STATION	1,480	869	44	2,393	Great Sand Dunes NP	58.7	40.8
11	HOLCIM (US) INC. PORTLAND CEMENT	372	2,589	288	3,250	Great Sand Dunes NP	66.0	49.2
12	PUBLIC SERVICE CO - COMANCHE	13,854	8,415	178	22,447	Great Sand Dunes NP	84.5	265.6
13	TRI STATE GENERATION - NUCLA	1,509	1,716	101	3,327	Black Canyon NP	70.6	47.1
14	PUBLIC SERVICE CO - CAMEO	2,586	1,051	112	3,750	Black Canyon NP	70.5	53.2
15	PUBLIC SERVICE CO - HAYDEN	2,657	7,694	284	10,634	Mt Zirkel WA	31.6	336.5
16	TRI STATE GENERATION - CRAIG	3,586	16,807	235	20,628	Flat Tops WA	47.7	432.4
	Totals:	65,358	71,821	2,906				

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth below are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority's Rawhide Power Plant (unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit (see below).
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCo) Valmont Power Plant (unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO2

and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the state has determined that the facility's closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler (see below).
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of unit 3 by 2018 satisfies the PM RP requirements in this planning period; for unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources (see below).
10. The state has determined that the Black Hills Energy Clark Power Plant (units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source (see below).
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source (see below).
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association's Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source (see below).
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO2, NOx, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation No. 3.
15. The PSCo Hayden Power Plant (units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association's Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period. The state has determined that unit 3 is subject-to-RP and has conducted an emission control analysis for the unit (see below).

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

(1) The costs of compliance,
(2) The time necessary for compliance,
(3) The energy and non-air quality environmental impacts of compliance, and
(4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

8.5.1 Rationale for Point Source RP Determinations

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NOx controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state's facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state's analyses and supporting the state's RP determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix D of this document and the TSD.

8.5.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO2 and NOx control equipment. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix D.

8.5.1.2 The time necessary for compliance.

Regulation No 3, Part F, Section VI.B.4. requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

8.5.1.3 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

8.5.1.4 The remaining useful life of the source. For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation No. 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state's RP determinations.

8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA's federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented below and in Appendix D.

8.5.1.6 Overview of the RP Determinations for Each Source. This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". *See,* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See,* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate.

When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO2 and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on reasonable progress electric generating units, for reasons described below, the state is employing guidance criteria to aid in its RP assessment, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO2 emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[39] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors.

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[39] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[40] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[41] The $5,000/ton criterion is also consistent with and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control

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[40] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[41] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, have the ability to provide significant NOx reductions, but also have initial capital dollar requirements that can approach or exceed $100 million per unit.[42] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[43] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[44] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

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[42] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[43] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[44] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

8.5.2 *Point Source RP Determinations*

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources

Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO_2 Control Type	SO_2 Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe.

The following presents an overview of Colorado's RP control determinations:

8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

SO2 RP Determination for PRPA Rawhide Unit 101

Dry FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO2 reduction. The state has elected to consider EPA's BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO_2 scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent*: Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO_2 scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.
- *Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-

nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO2 emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 – SO2 Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Fuel switching – NG	906	$237,424,331	$262,169

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO2 emission limits as a demonstration are as follows:

SO2 Control Method	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.11	
Existing Dry FGD	0.09	0.01
Dry FGD – tighter limit	0.07	0.03
Fuel switching – NG	0.00	0.87

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO2 RP is the following SO2 emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

Particulate Matter RP Determination for PRPA Rawhide

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}.

The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx RP Determination for PRPA Rawhide

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
ECC	448	$288,450	$644
SNCR	504	$1,596,000	$3,168
Fuel switching – NG	545	$237,424,331	$435,681
SCR	1,185	$12,103,000	$10,214

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.302	
ECC	0.126	0.45
SNCR	0.121	0.46
Fuel Switching – NG	0.118	0.47
SCR	0.061	0.59

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State's RP determination.

Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. CENC submitted a “Reasonable Progress Control Evaluation” on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

SO2 RP Determination for CENC – Boiler 3

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO2 emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state.

Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 3 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	147	$1,340,661	$9,114
Fuel Switching – Natural Gas	245	$1,428,911	$5,828

DSI – Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

Particulate Matter RP Determination for CENC – Boiler 3

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM10) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CENC – Boiler 3

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfire air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
FGR	33.7	$1,042,941	$30,929
SNCR	50.6	$513,197	$10,146
Fuel switching – NG	84.3	$1,428,911	$16,950
ROFA w/ Rotamix	77	$978,065	$9,496
Regenerative SCR	96.3	$978,065	$10,160
High temperature SCR	125.6	$1,965,929	$15,651
Low temperature SCR	144.5	$2,772,286	$19,187

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in section 8.4 above.

All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

SO2 RP Determination for CSU – Nixon

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO2 emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nixon Unit 1 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	2,473	$9,438,692	$1,997
Dry FGD @ 78% control (0.10 lb/MMBtu annual average)	3,215	$12,036,604	$3,744
Dry FGD @ 85% control (0.07 lb/MMBtu annual average)	3,392	$13,399,590	$3,950

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI – reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Nixon – Unit 1	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.45	
DSI	0.18	0.44
Dry FGD (LSD)	0.10	0.46
Dry FGD (LSD)	0.07	0.50

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton SO_2 removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

Particulate Matter RP Determination for CSU – Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for $PM/PM_{10.}$ The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CSU – Nixon

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Nixon Unit 1 - NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Ultra-low NOx Burners (ULNBs)	471	$567,000	$1,203
Overfire Air (OFA)	589	$403,000	$684
ULNBs+OFA	707	$907,000	$1,372
Selective Non-Catalytic Reduction (SNCR)	707	$3,266,877	$4,564
ULNB/SCR layered approach	1,720	$11,007,000	$6,398
Selective Catalytic Reduction (SCR)	1,720	$11,010,000	$6,400

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Nixon – Unit 1	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.26	
ULNB	0.21	0.15
OFA	0.19	0.15
ULNB+OFA	0.18	0.16
SNCR	0.18	0.16
ULNB + SCR	0.07	0.24
SCR	0.07	0.24

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above RP determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1.

A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shutdown 12/31/2013, resulting in SO2, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

8.5.2.5 RP Determination for Holcim's Florence Cement Plant

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NO_X, SO_2, and PM/PM_{10} emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM_{10}, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO_2, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NO_X precalciner, indirect firing, Low-NO_X burners, staged combustion and a Linkman Expert Control System for NO_X, and by the use of good combustion practices for both NO_X and SO_2.In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM_{10} emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion NO_X controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a SO_2 emission rate of 99.17 lbs/hour, a NO_X emission rate of

837.96 pounds per hour (lbs/hour), and a PM_{10} emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM_{10} emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

SO_2 RP Determination for Holcim Portland Plant – Kiln System

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the SO_2 emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2). The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO_2. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO_2 per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO_2 value of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term SO_2 emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO_2 per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim’s wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Particulate Matter RP Determination for Holcim Portland Plant – Kiln System

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding PM_{10} emissions rates. The facility is currently permitted to emit 246.3 tpy of PM_{10} from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of PM_{10} per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM_{10}). The actual kiln system PM_{10} emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of PM_{10} per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for PM_{10}, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates – the baseline emission rate of 0.08 pound of PM_{10} per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM_{10} per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change. The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates (NO_3) followed by sulfates (SO_4).The contribution of PM_{10} to the total visibility impairment was insignificant in the analysis. The level of PM_{10} emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of PM_{10} emissions from the kiln system on visibility impairment, the state has determined that no additional PM_{10} emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of PM_{10} (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the PM_{10} emissions.

NO_X RP Determination for Holcim Portland Plant – Kiln System

There are a number of technologies available to reduce NO_X emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NO_X burners, staged combustion, a low-NO_X precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NO_X emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable “available” control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: “However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns.” Based on our research and EPA’s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NO_X to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4th quarter of 2006. Holcim estimated that NO_X emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

NOx Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NOx Emissions (tpy)
Baseline NOx Emissions	-	4.97	3,185.7*
SNCR w/ existing LNB	45%**	2.73	2,086.8

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Holcim Portland Plant – Kiln System				
NOx Control Technology	NOx Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline NOx Emissions	-			
SNCR w/existing LNB (45% control)	1,098.9	$2,520,000*	$2,293	-

* Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NO_X RP limitations. The following table lists the projected visibility improvements for NO_X controls, as identified by Holcim:

Holcim Portland Plant – Kiln System		
NOx Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.814	N/A
SNCR w/ existing LNB (45% overall NO_X control efficiency) Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr NO_X, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.526	0.288

For the kiln, the state has determined that SNCR w/existing LNB is the best NO_X control system available with NO_X RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NO_X reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Nucla – Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Limestone Injection Improvements	526	$914,290	$4,161
Spray Dry Absorber (dry FGD)	1,162	$7,604,627	$6,547
Limestone Injection Improvements + dry FGD	1,254	$9,793,222	$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be 'run harder' with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State's estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013.

A complete analysis that supports the RP determination for the Nucla facility can be found in Appendix D.

8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_X, SO_2,

PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Craig – Unit 3

Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO2 reduction. The state considers EPA's BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO_2 scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

- *Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that TriState cannot use a more reactive sorbent or increase the pulverization level of sorbent.

- *Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO_2 limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets

Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 3	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.33	
Dry FGD	0.15	0.26
Dry FGD	0.07	0.38

The current SO2 emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO2, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

PM10 RP Determination for Craig – Unit 3

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Craig – Unit 3

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Unit 3.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	853	$4,173,000	$4,887
SCR	4,281	$29,762,387	$6,952

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (2nd half 2009)	0.365	
SNCR	0.240	0.32
SCR	0.070	0.79

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.
Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: $4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

8.5.2.8 RP Determination for Public Service Company's Cameo Station

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO2, NOx and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS' of both phases are to be coordinated.

This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state's 12 mandatory federal Class I areas.

9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment;
- Consult with other states to develop coordinated emission management strategies for Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado where emissions from other states cause or contribute to visibility impairment;
- Document the technical basis on which the state is relying to determine its' apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:
  (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
  (2) Emission limitations and schedules for compliance to achieve the RP goal;
  (3) Measures to mitigate the impacts of construction activities;

(4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
(5) Source retirement and replacement schedules;
(6) Enforceability of emission limitations and control measures; and
(7) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

The following sections 9.2 and 9.3 address these LTS requirements.

9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized below.

9.2.1 Existing Impairment

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation No. 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule. As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation No. 3 noted above. In addition, Regulation 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado’s requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

9.2.1.1 Mt. Zirkel Wilderness

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO2 and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

9.2.1.2 BART and Emission Limitations

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation No. 3 result in new control requirements for these units to meet BART.

9.2.1.3 Monitoring

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of ‘before and after emission reductions’ will be met.

9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation No. 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

9.2.1.5 Ongoing Air Pollution Programs

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

9.2.2 Prevention of Future Impairment

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Generally, Colorado considers its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado’s Regulation No. 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

9.2.4 Federal Land Manager Consultation and Communication

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that "The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated." Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation 3, as described above in section 9.2.1, and a commitment to utilize the FETS to track fire data as described above in section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

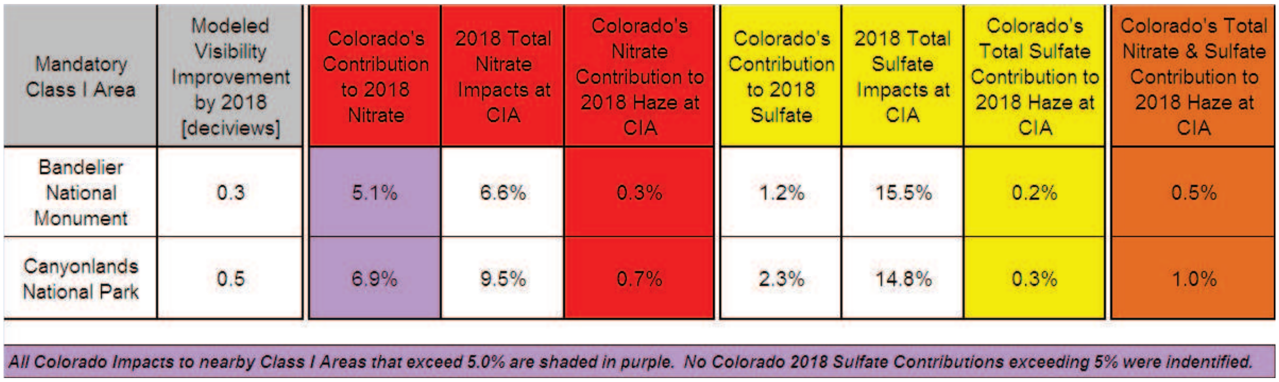
9.4 Regional Haze Long Term Strategy

The following presents Colorado's Long Term Strategy (LTS) for Regional Haze.

9.4.1 Impacts on Other States

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states' Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado's total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands



Mandatory Class I Area	Modeled Visibility Improvement by 2018 [deciviews]	Colorado's Contribution to 2018 Nitrate	2018 Total Nitrate Impacts at CIA	Colorado's Nitrate Contribution to 2018 Haze at CIA	Colorado's Contribution to 2018 Sulfate	2018 Total Sulfate Impacts at CIA	Colorado's Total Sulfate Contribution to 2018 Haze at CIA	Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA
Bandelier National Monument	0.3	5.1%	6.6%	0.3%	1.2%	15.5%	0.2%	0.5%
Canyonlands National Park	0.5	6.9%	9.5%	0.7%	2.3%	14.8%	0.3%	1.0%

All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were indentified.

9.4.2 Impacts from Other States

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado's Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

9.4.3 Document Technical Basis for RPGs

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

9.4.4 Identify Anthropogenic Sources

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs

Below is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NOx, SO2 and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NOx, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality

Control Commission Regulations:

- Regulation Number 1: Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
    - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements
    - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
    - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4: New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
    - Regulation Number 4 is in the SIP. One provision, the Masonry Heater Test Method, is state only. Colorado is waiting for EPA to develop their own test method – the state will adopt it when EPA goes final
- Regulation Number 6: Standards of Performance for New Stationary Sources
    - Part A – Federal NSPS's adopted by the state – EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
    - Part B – state-only NSPS regulations
- Regulation Number 7: Control of Ozone Precursors
    - The majority of Regulation Number 7 for VOC and NOx control is in the SIP or has been submitted for approval into the SIP – these provisions relate to VOC and NOx control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized below
- Regulation Number 9: Open Burning, Prescribed Fire and Permitting – state-only
- Regulation Number 11: Motor Vehicle Emission Inspection Program – Parts A-F in the SIP
- Regulation Number 16: Street Sanding Emissions – In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows. It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO2 from metro Denver power plants, approximately 6,500 tpy of SO2 from the Comanche power plant, and approximately 18,000 tpy of SO2 from the Craig and Hayden power plants – state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 – Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NOx and VOC emissions reductions of approximately 8,900 tpy – In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range

region that have achieved VOC emission reductions of approximately 8,400 tpy – state-only

- Mobile source emissions controls for VOCs and NOx through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 – Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions – state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NOx and VOC emissions reductions of approximately 7,100 tpy by 2010 – state-only
- PM10 emission reduction programs in PM10 maintenance areas throughout the state – In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide – In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide – state-only
- Renewable energy requirements that are driving current and future NOx, SO2 and PM emission reductions from coal-fired power plants - Ballot Initiative 37 – by requiring electricity to be obtained from renewable resources – state-only
- Attaining and maintaining the PM10 and PM2.5 standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver's Brown Cloud) by 28% between 1991 and 2006) – state-only
- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program – state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 – gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2008-2009 Report to the Public available at the following website:

http://www.cdphe.state.co.us/ap/rttplinks.html

As recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

The table below shows the designation status for all current and former non-attainment areas.

Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT

PM10	**Redesignations**	**Plan Amendments**
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	10-year update: AQCC approved 12/16/10
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Denver	AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02	Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08
Lamar	AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05	None
Pagosa Springs	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010

Carbon Monoxide	**Redesignations**	**Plan Amendments**
Colorado Springs	AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99	- Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01 - Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Denver	AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02	- Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	10-year update: AQCC approved 12/16/10
Greeley	AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99	- Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Longmont	AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99	- Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08

Ozone	**Redesignations**	**Plan Amendments**
Denver/Northern Front Range	AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01 Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05	- 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg. 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08 - Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Lead	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	
Nitrogen Dioxide	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

9.4.6 Measures to Mitigate the Impacts of Construction Activities

Regulations 1 and 3 are currently part of Colorado's EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation 1, sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation 1 to most directly address these sources of fine and course particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

9.4.7 Smoke Management

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement[45]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit's conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado's program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation No. 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;

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[45] The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD "Agricultural Burning in Colorado, 2003 and 2004 Inventories".

- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. A permit is granted only if the Division's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division's web site contains information about various aspects of Colorado's Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: http://www.cdphe.state.co.us/ap/smoke/

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Nos. 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

9.4.9 Source Retirement and Replacement Schedules

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation No. 3. Unless otherwise indicated in those chapters or in Regulation No. 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 – the fleet turn-over rate was developed utilizing EPA-approved methodologies.

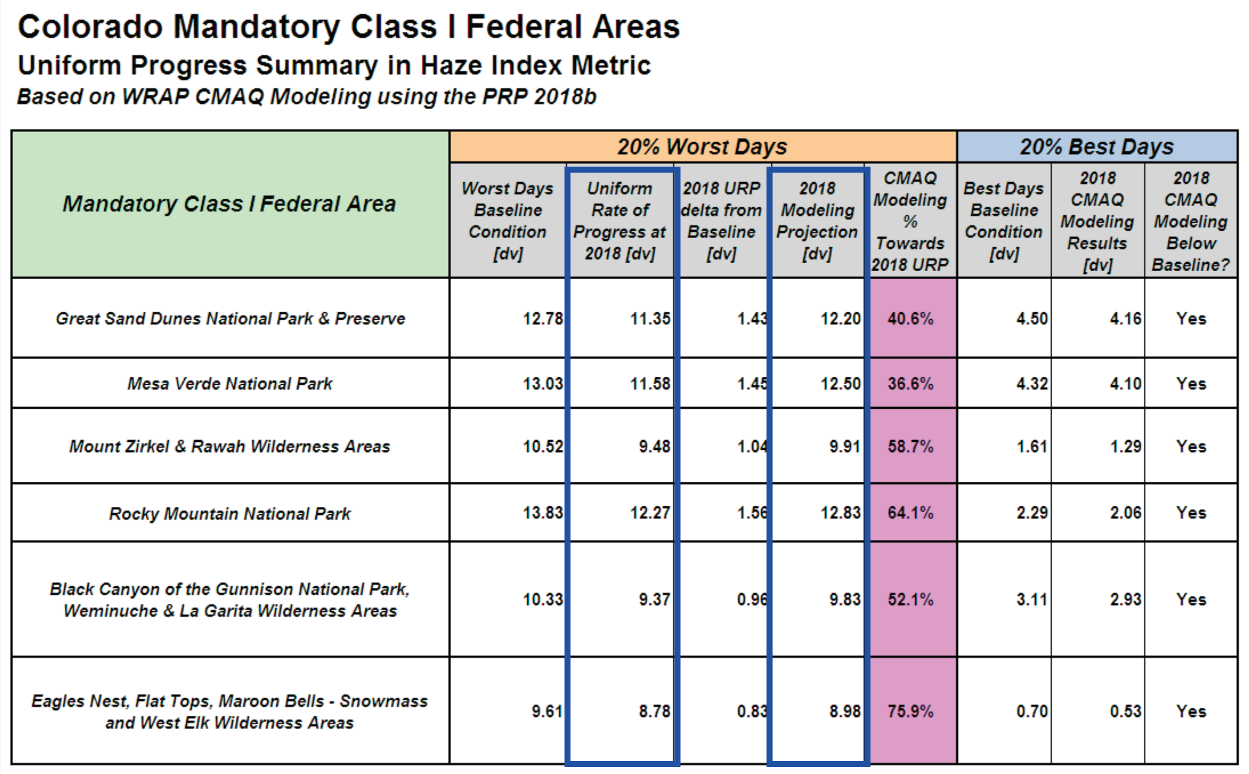
9.4.10 Anticipated Net Effect on Visibility

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable. Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources.

Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO2 emission reduction of 58,907 tons per year and a total NOx emission reduction of 123,497 tons per year by 2018. (SO2 and NOx are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented below. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP



Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*					*20% Best Days*		
	Worst Days Baseline Condition [dv]	*Uniform Rate of Progress at 2018 [dv]*	*2018 URP delta from Baseline [dv]*	*2018 Modeling Projection [dv]*	*CMAQ Modeling % Towards 2018 URP*	*Best Days Baseline Condition [dv]*	*2018 CMAQ Modeling Results [dv]*	*2018 CMAQ Modeling Below Baseline?*
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Uniform Rate of Progress for 2018

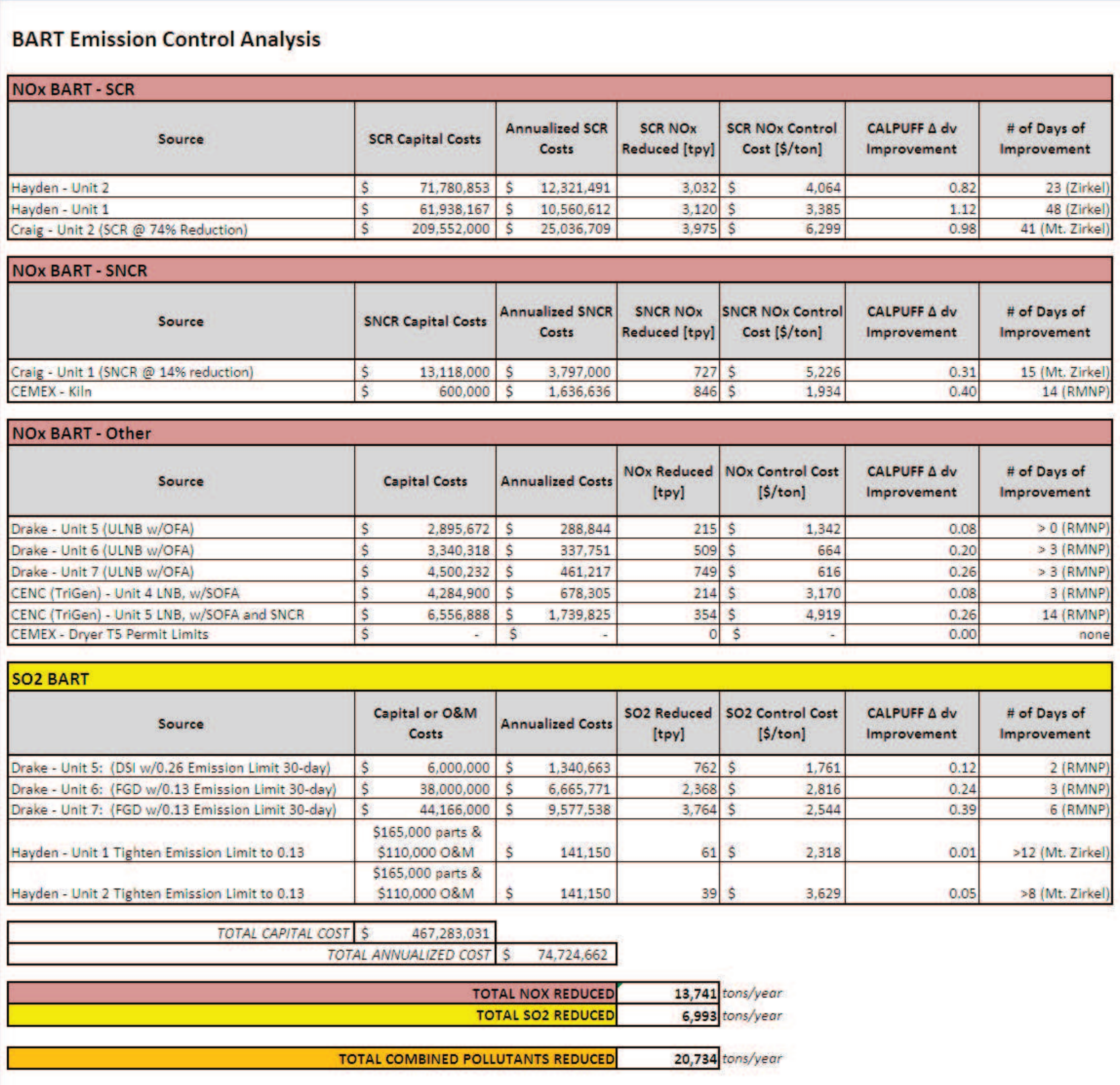
Projected Amount of Progress by 2018 Towards URP

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized below in Figures 9-4, 9-5 and 9-6.

2010 BART:	20,734 tons/year
2010 BART alternative:	37,488 tons/year
<u>2010 RP:</u>	<u>12,624 tons/year</u>
Total:	70,846 tons/year

The following figures also present "CALPUFF" modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 above because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

Figure 9-3 Emission Reductions Achieved by 2010 BART Determinations



BART Emission Control Analysis

NOx BART - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Hayden - Unit 2	$ 71,780,853	$ 12,321,491	3,032	$ 4,064	0.82	23 (Zirkel)
Hayden - Unit 1	$ 61,938,167	$ 10,560,612	3,120	$ 3,385	1.12	48 (Zirkel)
Craig - Unit 2 (SCR @ 74% Reduction)	$ 209,552,000	$ 25,036,709	3,975	$ 6,299	0.98	41 (Mt. Zirkel)

NOx BART - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 1 (SNCR @ 14% reduction)	$ 13,118,000	$ 3,797,000	727	$ 5,226	0.31	15 (Mt. Zirkel)
CEMEX - Kiln	$ 600,000	$ 1,636,636	846	$ 1,934	0.40	14 (RMNP)

NOx BART - Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5 (ULNB w/OFA)	$ 2,895,672	$ 288,844	215	$ 1,342	0.08	> 0 (RMNP)
Drake - Unit 6 (ULNB w/OFA)	$ 3,340,318	$ 337,751	509	$ 664	0.20	> 3 (RMNP)
Drake - Unit 7 (ULNB w/OFA)	$ 4,500,232	$ 461,217	749	$ 616	0.26	> 3 (RMNP)
CENC (TriGen) - Unit 4 LNB, w/SOFA	$ 4,284,900	$ 678,305	214	$ 3,170	0.08	3 (RMNP)
CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR	$ 6,556,888	$ 1,739,825	354	$ 4,919	0.26	14 (RMNP)
CEMEX - Dryer T5 Permit Limits	$ -	$ -	0	$ -	0.00	none

SO2 BART

Source	Capital or O&M Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day)	$ 6,000,000	$ 1,340,663	762	$ 1,761	0.12	2 (RMNP)
Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day)	$ 38,000,000	$ 6,665,771	2,368	$ 2,816	0.24	3 (RMNP)
Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day)	$ 44,166,000	$ 9,577,538	3,764	$ 2,544	0.39	6 (RMNP)
Hayden - Unit 1 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	61	$ 2,318	0.01	>12 (Mt. Zirkel)
Hayden - Unit 2 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	39	$ 3,629	0.05	>8 (Mt. Zirkel)

TOTAL CAPITAL COST	$ 467,283,031	
TOTAL ANNUALIZED COST		$ 74,724,662

TOTAL NOX REDUCED	**13,741**	*tons/year*
TOTAL SO2 REDUCED	**6,993**	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	**20,734**	*tons/year*

Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

Facility	NOx Emissions Average 2006-2008 (tpy)	NOx Emissions from Alternative (TPY)	Total NOx Emissions Reduced (TPY)	SO2 Emissions Average 2006 -2008 (tpy)	SO2 Emissions from Alternative (TPY)	Total SO2 Emissions Reduced (TPY)
Arapahoe						
Unit 3	1,770	0		925	0	
Unit 4	1,148	900[46]		1,765	1.28	
Cherokee						
Unit 1	1,556	0		2,221	0	
Unit 2	2,895	0		1,888	0	
Unit 3	1,866	0		743	0	
Unit 4	4,274	2,063[47]		2,135	7.81[48]	
Valmont	2,314	0		758	0	
Pawnee	4,538	1,403[49]		13,472	2,406[50]	
Totals	20,361	4,366	15,995	23,908	2,415	21,493

Total Emission Reductions Achieved: 37,488 tons per year

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[46] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

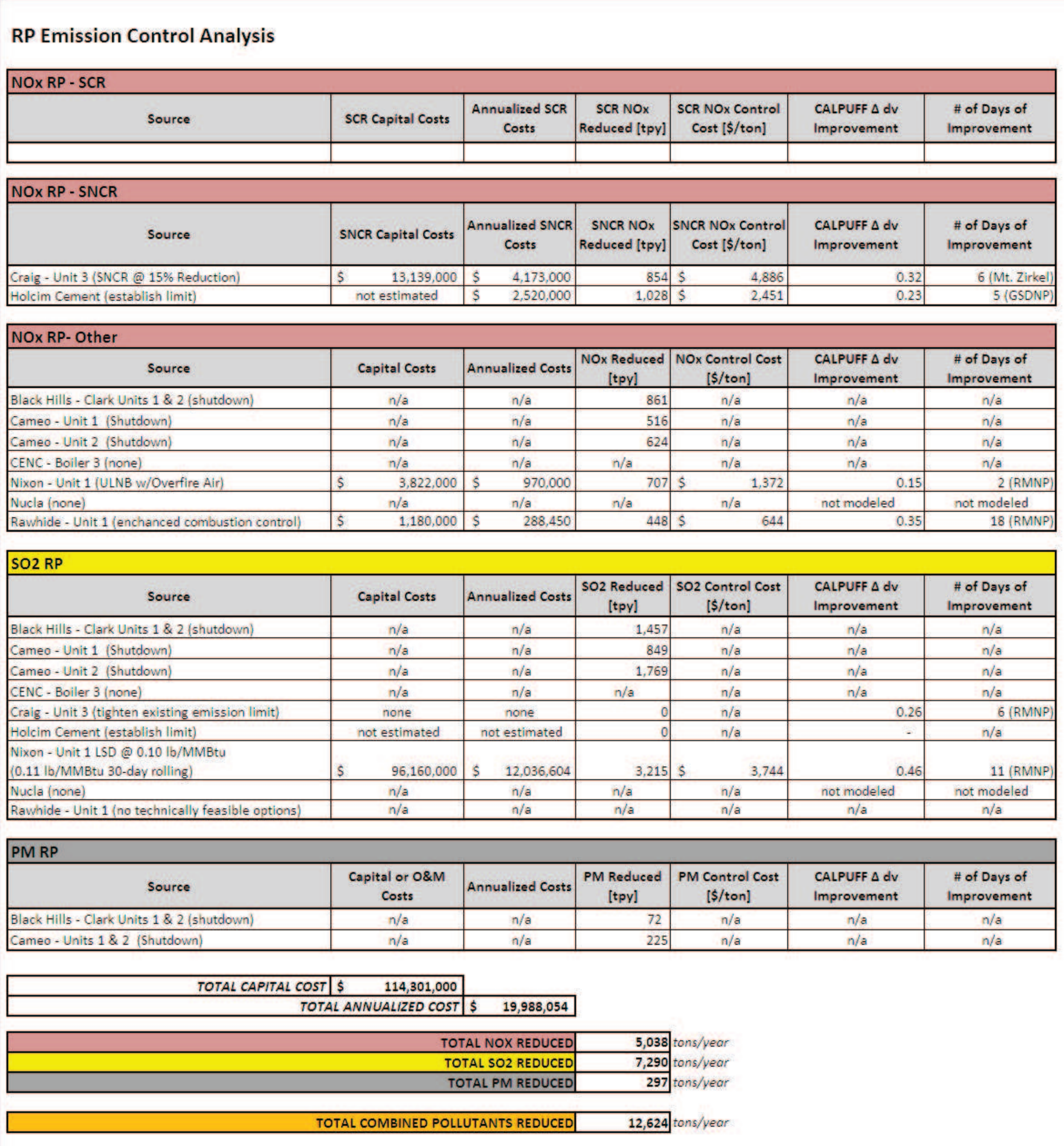
[47] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[48] Emissions at 0.0006 lb SO2/MMBtu

[49] Emissions at 0.07 lb NOx/MMBtu

[50] Emissions at 0.12 lb SO2/MMBtu

Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations



RP Emission Control Analysis

NOx RP - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement

NOx RP - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 3 (SNCR @ 15% Reduction)	$ 13,139,000	$ 4,173,000	854	$ 4,886	0.32	6 (Mt. Zirkel)
Holcim Cement (establish limit)	not estimated	$ 2,520,000	1,028	$ 2,451	0.23	5 (GSDNP)

NOx RP- Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	861	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	516	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	624	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Nixon - Unit 1 (ULNB w/Overfire Air)	$ 3,822,000	$ 970,000	707	$ 1,372	0.15	2 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (enchanced combustion control)	$ 1,180,000	$ 288,450	448	$ 644	0.35	18 (RMNP)

SO2 RP

Source	Capital Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	1,457	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	849	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	1,769	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Craig - Unit 3 (tighten existing emission limit)	none	none	0	n/a	0.26	6 (RMNP)
Holcim Cement (establish limit)	not estimated	not estimated	0	n/a	-	n/a
Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling)	$ 96,160,000	$ 12,036,604	3,215	$ 3,744	0.46	11 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (no technically feasible options)	n/a	n/a	n/a	n/a	n/a	n/a

PM RP

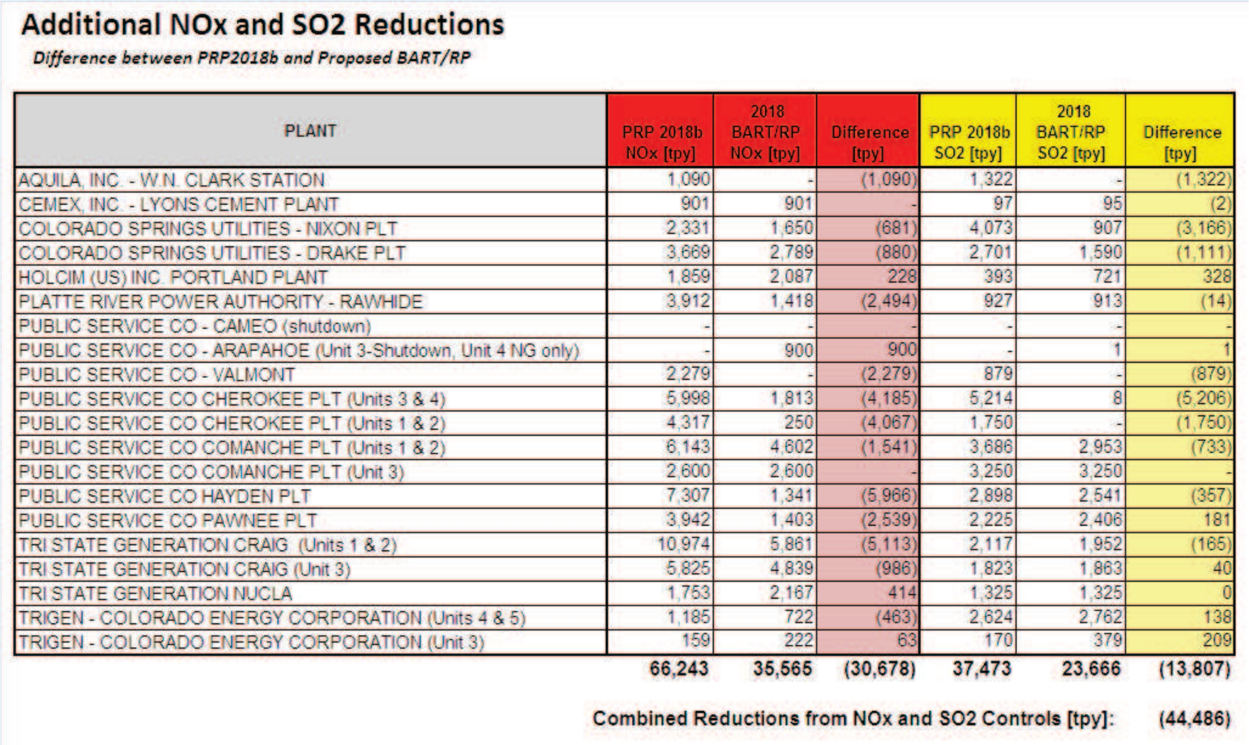
Source	Capital or O&M Costs	Annualized Costs	PM Reduced [tpy]	PM Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	72	n/a	n/a	n/a
Cameo - Units 1 & 2 (Shutdown)	n/a	n/a	225	n/a	n/a	n/a

TOTAL CAPITAL COST	$ 114,301,000	
TOTAL ANNUALIZED COST		$ 19,988,054

TOTAL NOX REDUCED	5,038	*tons/year*
TOTAL SO2 REDUCED	7,290	*tons/year*
TOTAL PM REDUCED	297	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	12,624	*tons/year*

Of these 70,800 tons of SO2 and NOx reduced due to 2010 BART and RP, approximately 44,500 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 below presents this analysis for each of the BART and RP sources.

Figure 9-6 Difference Between the WRAP and Final BART/RP Emissions for NOx and SO2



Additional NOx and SO2 Reductions

Difference between PRP2018b and Proposed BART/RP

PLANT	PRP 2018b NOx [tpy]	2018 BART/RP NOx [tpy]	Difference [tpy]	PRP 2018b SO2 [tpy]	2018 BART/RP SO2 [tpy]	Difference [tpy]
AQUILA, INC. - W.N. CLARK STATION	1,090	-	(1,090)	1,322	-	(1,322)
CEMEX, INC. - LYONS CEMENT PLANT	901	901	-	97	95	(2)
COLORADO SPRINGS UTILITIES - NIXON PLT	2,331	1,650	(681)	4,073	907	(3,166)
COLORADO SPRINGS UTILITIES - DRAKE PLT	3,669	2,789	(880)	2,701	1,590	(1,111)
HOLCIM (US) INC. PORTLAND PLANT	1,859	2,087	228	393	721	328
PLATTE RIVER POWER AUTHORITY - RAWHIDE	3,912	1,418	(2,494)	927	913	(14)
PUBLIC SERVICE CO - CAMEO (shutdown)	-	-	-	-	-	-
PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only)	-	900	900	-	1	1
PUBLIC SERVICE CO - VALMONT	2,279	-	(2,279)	879	-	(879)
PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4)	5,998	1,813	(4,185)	5,214	8	(5,206)
PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2)	4,317	250	(4,067)	1,750	-	(1,750)
PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2)	6,143	4,602	(1,541)	3,686	2,953	(733)
PUBLIC SERVICE CO COMANCHE PLT (Unit 3)	2,600	2,600	-	3,250	3,250	-
PUBLIC SERVICE CO HAYDEN PLT	7,307	1,341	(5,966)	2,898	2,541	(357)
PUBLIC SERVICE CO PAWNEE PLT	3,942	1,403	(2,539)	2,225	2,406	181
TRI STATE GENERATION CRAIG (Units 1 & 2)	10,974	5,861	(5,113)	2,117	1,952	(165)
TRI STATE GENERATION CRAIG (Unit 3)	5,825	4,839	(986)	1,823	1,863	40
TRI STATE GENERATION NUCLA	1,753	2,167	414	1,325	1,325	0
TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5)	1,185	722	(463)	2,624	2,762	138
TRIGEN - COLORADO ENERGY CORPORATION (Unit 3)	159	222	63	170	379	209
	66,243	**35,565**	**(30,678)**	**37,473**	**23,666**	**(13,807)**

Combined Reductions from NOx and SO2 Controls [tpy]: (44,486)

These substantial additional emission reductions will further the amount of progress achieved by 2018.

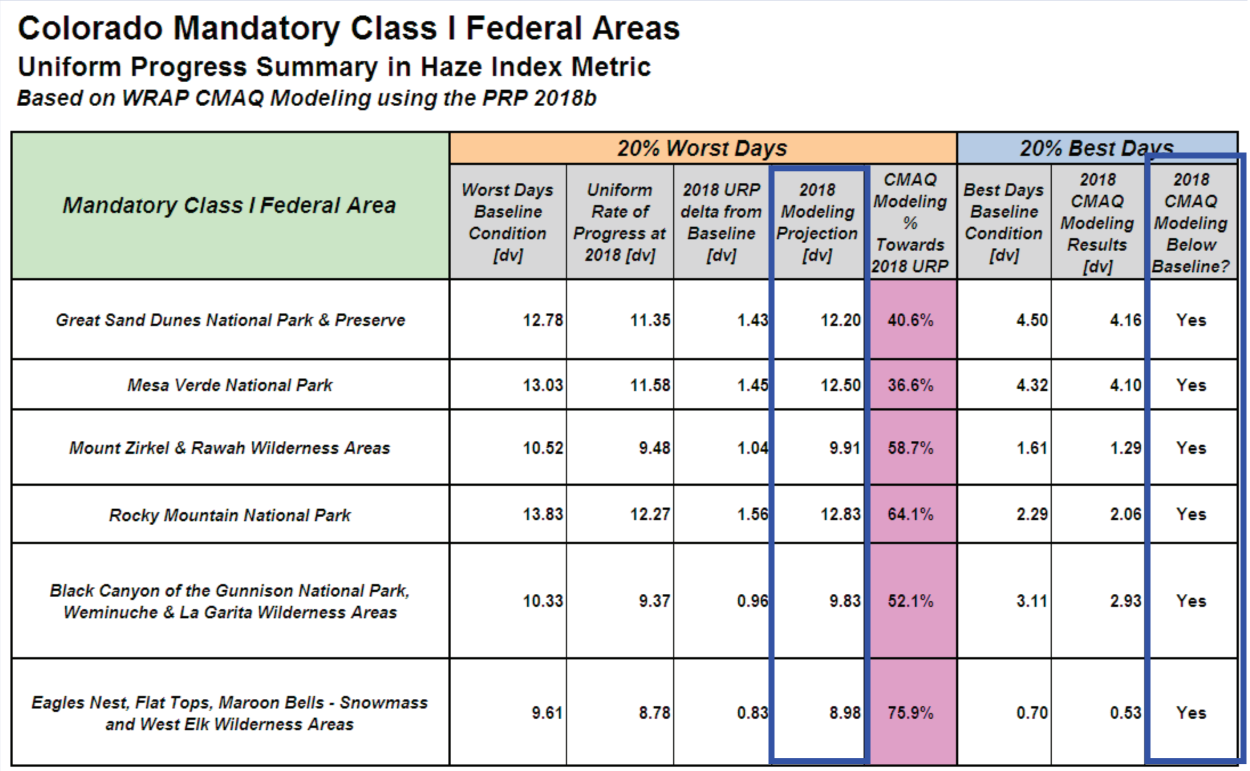
Colorado believes the combination of WRAP's CMAQ modeling and the Division's BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership's (WRAP's) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter, all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

Figure 9-7 Reasonable Progress Goals for Each Class I Area



Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*					*20% Best Days*		
	Worst Days Baseline Condition [dv]	*Uniform Rate of Progress at 2018 [dv]*	*2018 URP delta from Baseline [dv]*	*2018 Modeling Projection [dv]*	*CMAQ Modeling % Towards 2018 URP*	*Best Days Baseline Condition [dv]*	*2018 CMAQ Modeling Results [dv]*	*2018 CMAQ Modeling Below Baseline?*
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Reasonable Progress Goals for 2018

No Degradation of Visibility for the Best Days

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated above in section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted in substantial emission reductions that build on the reductions already achieved by other measures.

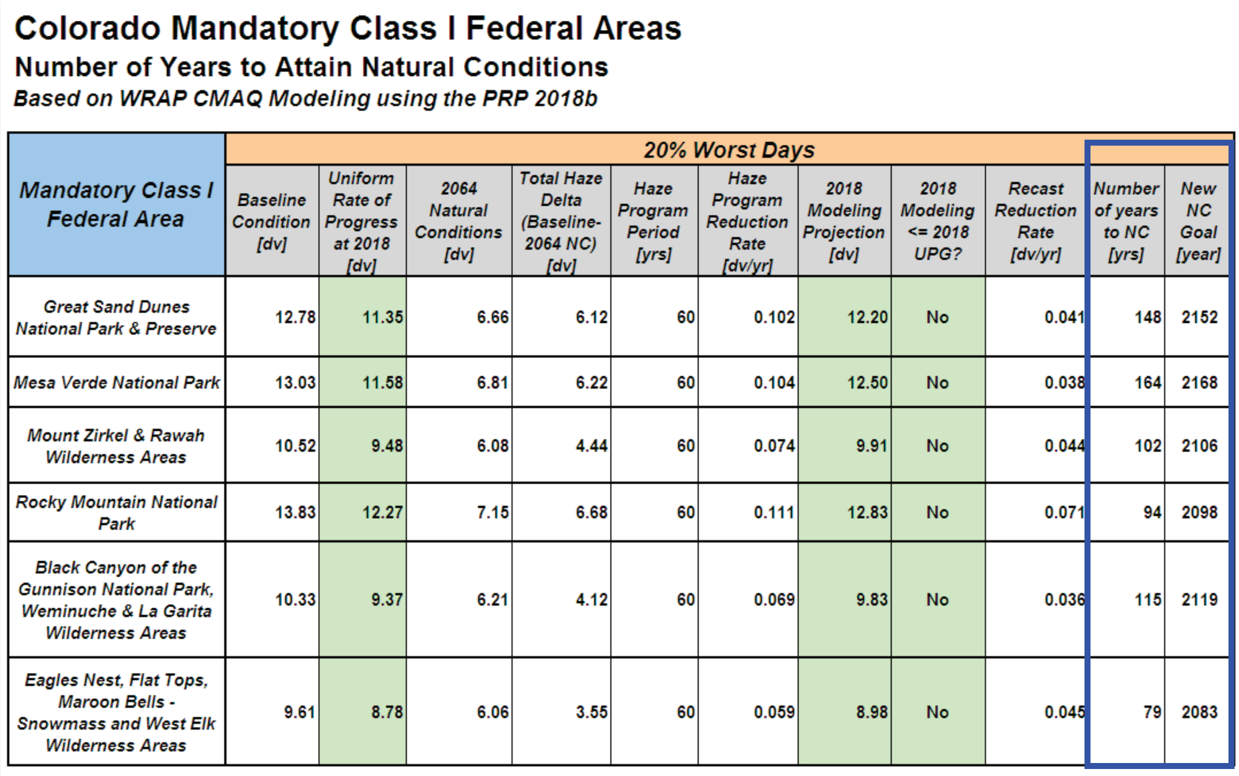
Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable. In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown below and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described above, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO2, NOx (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions



Colorado Mandatory Class I Federal Areas

Number of Years to Attain Natural Conditions

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*										
	Baseline Condition [dv]	*Uniform Rate of Progress at 2018 [dv]*	*2064 Natural Conditions [dv]*	*Total Haze Delta (Baseline-2064 NC) [dv]*	*Haze Program Period [yrs]*	*Haze Program Reduction Rate [dv/yr]*	*2018 Modeling Projection [dv]*	*2018 Modeling <= 2018 UPG?*	*Recast Reduction Rate [dv/yr]*	*Number of years to NC [yrs]*	*New NC Goal [year]*
Great Sand Dunes National Park & Preserve	12.78	11.35	6.66	6.12	60	0.102	12.20	No	0.041	148	2152
Mesa Verde National Park	13.03	11.58	6.81	6.22	60	0.104	12.50	No	0.038	164	2168
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	6.08	4.44	60	0.074	9.91	No	0.044	102	2106
Rocky Mountain National Park	13.83	12.27	7.15	6.68	60	0.111	12.83	No	0.071	94	2098
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	6.21	4.12	60	0.069	9.83	No	0.036	115	2119
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	6.06	3.55	60	0.059	8.98	No	0.045	79	2083

The following figures for Mesa Verde National Park illustrate the re-calculations.

Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018

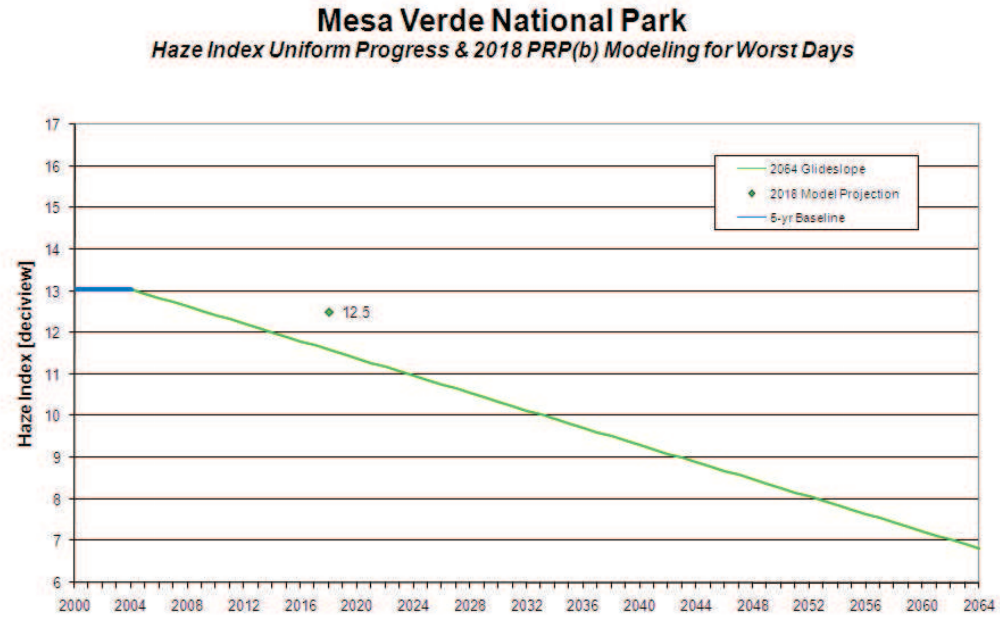
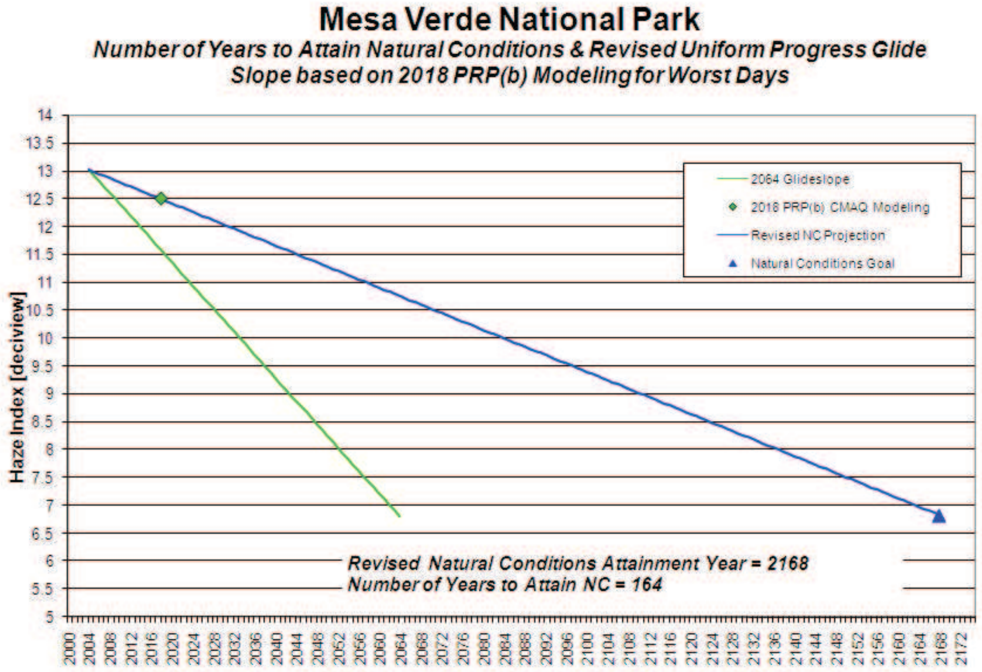


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

10.1 Future Consultation Commitments

10.1.1 FLM Consultation

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
    a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
    b. Summary of major new source permits issued;
    c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
    d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

10.1.2 Tribal Consultation

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

10.1.3 Inter-state Consultation/Coordination

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado's emissions may reasonable be anticipated to cause or contribute to visibility impairment in those state's federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

10.1.4 Regional Planning Coordination

As per the requirements of [51.308(c)(1)(i)],Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
4. Address fully the recommendations of WRAP, including Colorado's apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized below.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy

3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period
4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP;
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions
7. Assessment of Colorado's visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado.

The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable. These actions are described below and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.

4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3)requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized below.

10.4.1 Current Visibility Conditions

Colorado commits to determine and report current visibility conditions for the most and least impaired days using themost recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

10.4.2 Long Term Strategy Effectiveness

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

10.4.3 Affirmation of or Revisions to Reasonable Progress Goals

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at http://www.cdphe.state.co.us/ap/regionalhaze.html

11.1 Class I Area Technical Support Documents (TSDs) TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

Colorado State Implementation Plan for Regional Haze Technical Support Document – Black Canyon of the Gunnison National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Eagles Nest Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Flat Tops Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –La Garita Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Maroon Bells Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mesa Verde National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mount Zirkel Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rocky Mountain National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rawah Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Sand Dunes National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Weminuche Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –West Elk Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

11.2 Other Technical Support Documents In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

Colorado State Implementation Plan for Regional Haze Technical Support Document –Douglas Pass and Ripple Creek Pass Sites, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Agricultural Burning in Colorado 2003-4 Inventory, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

11.3 Long-Term Strategy Review Update In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

List of Appendices –

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

Newark, East (Barnett Shale) Field
Discovery Date – 10-15-1981

- **As of September 28, 2011 there are a total of gas wells 15,306 entered on RRC records.**

In addition, there are 3,212 permitted locations (represents pending oil or gas wells, where either the operator has not yet filed completion paperwork with the Commission, or the completed well has not yet been set up with a Commission identification number)**.**

- Currently, there are 180 commercial disposal wells in the 23-county area. So far in 2011, there have been no new commercial disposal well permits issued.

- This field produces in twenty five (25) counties: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Somervell, Stephens, Tarrant, and Wise. In addition, drilling permits have been issued for wells in Hamilton and Young counties.

- Gas Well Gas Production –
  January 2004 through December 2004 = 380 Bcf
  January 2005 through December 2005 = 505 Bcf
  January 2006 through December 2006 = 717 Bcf
  January 2007 through December 2007 = 1,104 Bcf
  January 2008 through December 2008 = 1,612Bcf
  January 2009 through December 2009 = 1,775 Bcf
  January 2010 through December 2010 = 1,847 Bcf
  January 2011 through July 2011 = 1,092 Bcf

- For January through July 2011 production accounts for 31% of Texas Production

- Drilling Permits Issued –
  January 2004 through December 2004 = 1,112
  January 2005 through December 2005 = 1,629
  January 2006 through December 2006 = 2,503
  January 2007 through December 2007 = 3,643
  January 2008 through December 2008 = 4,145
  January 2009 through December 2009 = 1,755
  January 2010 through December 2010 = 2,157
  January 2011 through August 2011 = 1,414

- There are a total of 231 operators in the Newark, East (Barnett Shale) Field.

Top Ten Gas Operators for January through July 2011 as follows:

Operator Name		Operator No.	Casinghead (MCF)	GW Gas (MCF)	Total Natural Gas (MCF)
1	DEVON ENERGY PRODUCTION CO, L.P.	216378	199,246	264,612,260	264,811,506
2	CHESAPEAKE OPERATING, INC.	147715	0	246,283,399	246,283,399
3	XTO ENERGY INC.	945936	322,942	180,301,876	180,624,818
4	EOG RESOURCES, INC.	253162	18,424,587	104,123,235	122,547,822
5	QUICKSILVER RESOURCES INC.	684830	0	84,432,820	84,432,820
6	CARRIZO OIL & GAS, INC.	135401	0	30,976,622	30,976,622
7	ENCANA OIL & GAS(USA) INC.	251691	28,431	29,876,339	29,904,770
8	RANGE PRODUCTION COMPANY	691703	5,447	19,787,015	19,792,462
9	WILLIAMS PROD. GULF COAST, L.P.	924558	0	19,001,118	19,001,118
10	ENERVEST OPERATING, L.L.C.	252131	0	15,912,812	15,912,812

Rapid photochemical Production of A Ozone at High Concentrations in a Rural Site During Winter

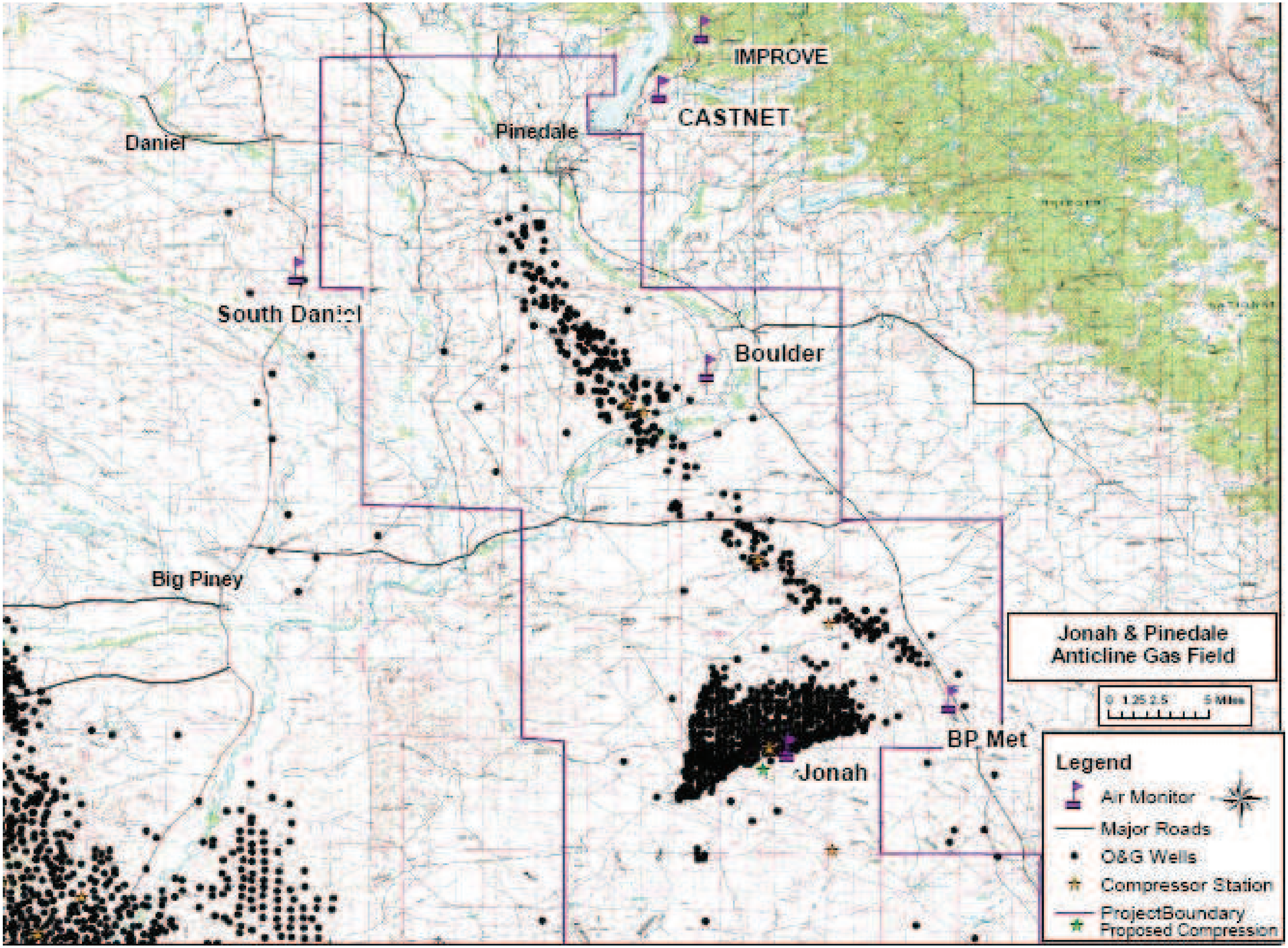
Russ Schnell, Sam Oltmans, and Ryan Neely[1] , Maggie Endres[2], John Molenar[3] and Allen White[1]

[1]NOAA, Earth System Research Laboratory, Boulder, CO 80305

[2]Wyoming Department of Air Quality, Cheyenne, WY

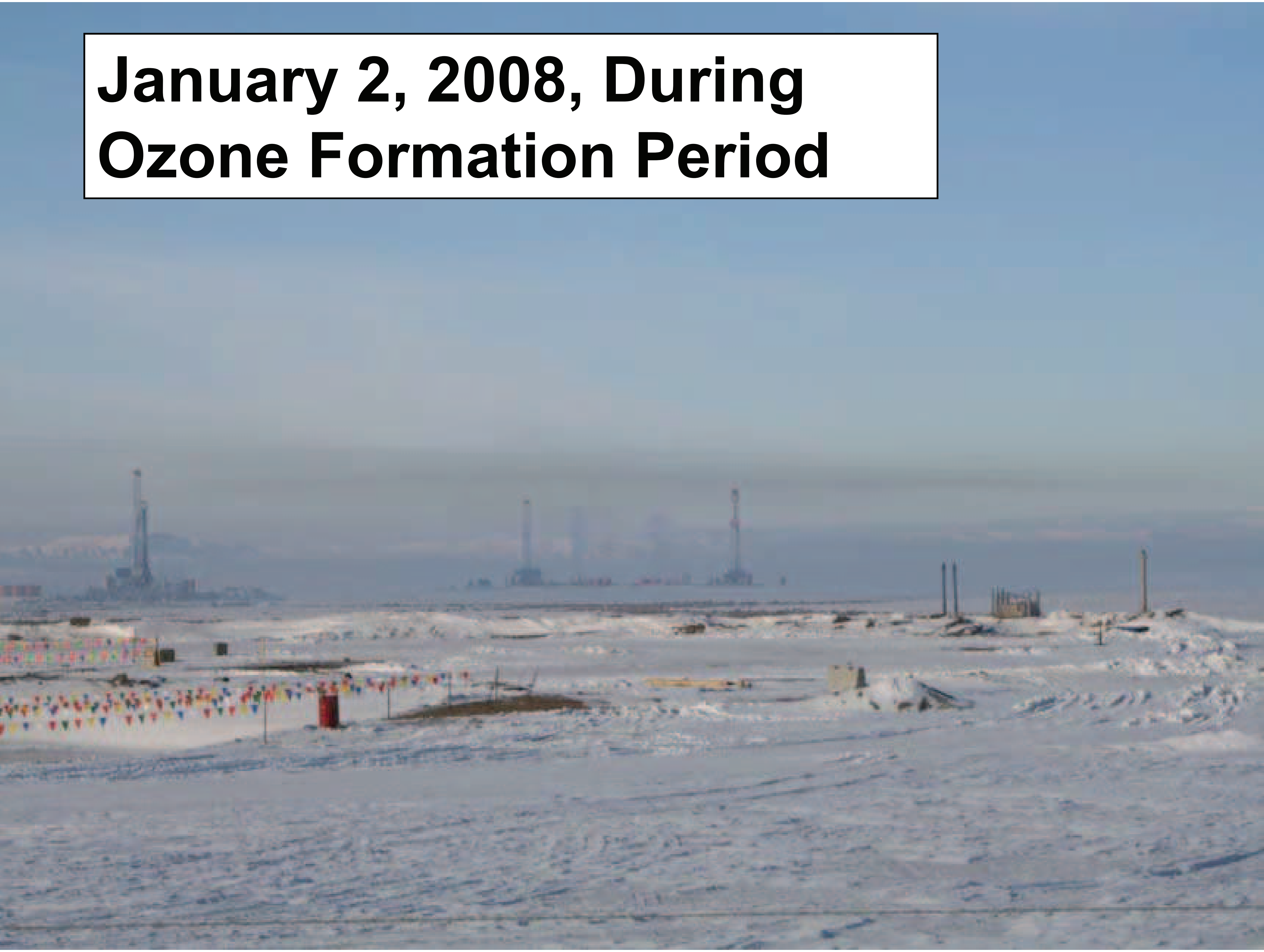
[3]Air Resource Specialists, Fort Collins. CO

Pinedale Anticline, Jonah, Wyoming

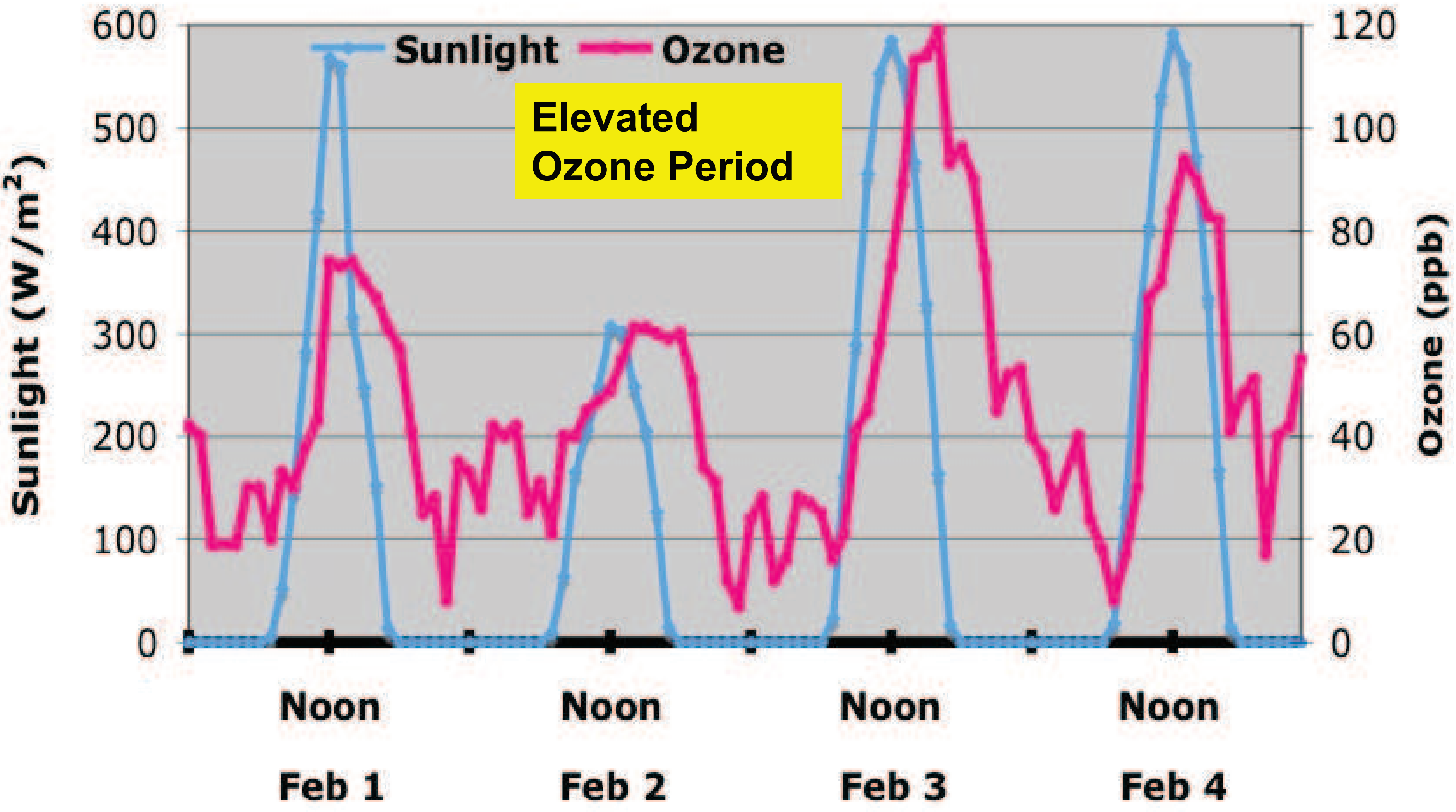


Well Density will increase 300% in 3-5 Years

January 2, 2008, During Ozone Formation Period

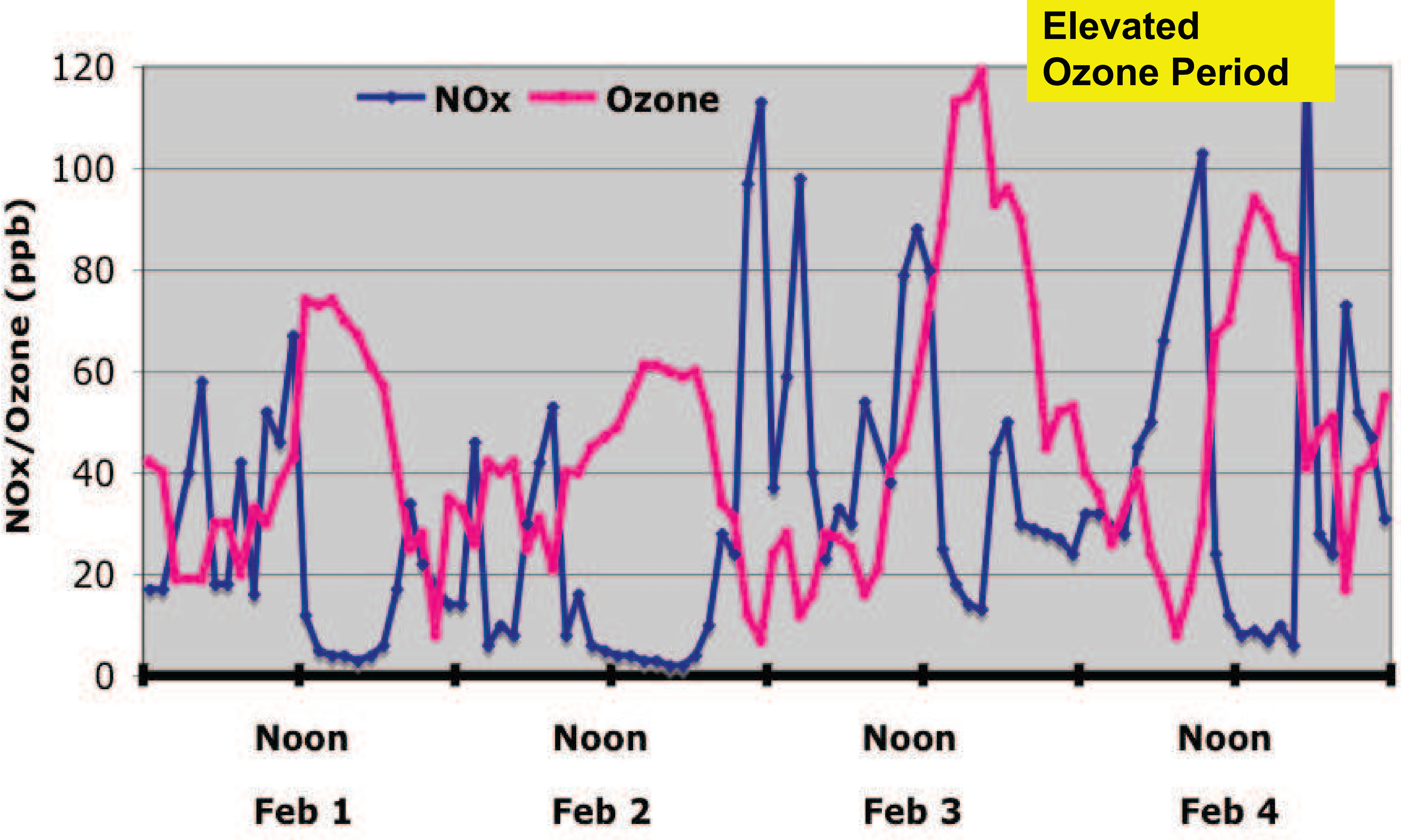


Solar Radiation and Ozone, Jonah, February 1-4, 2005

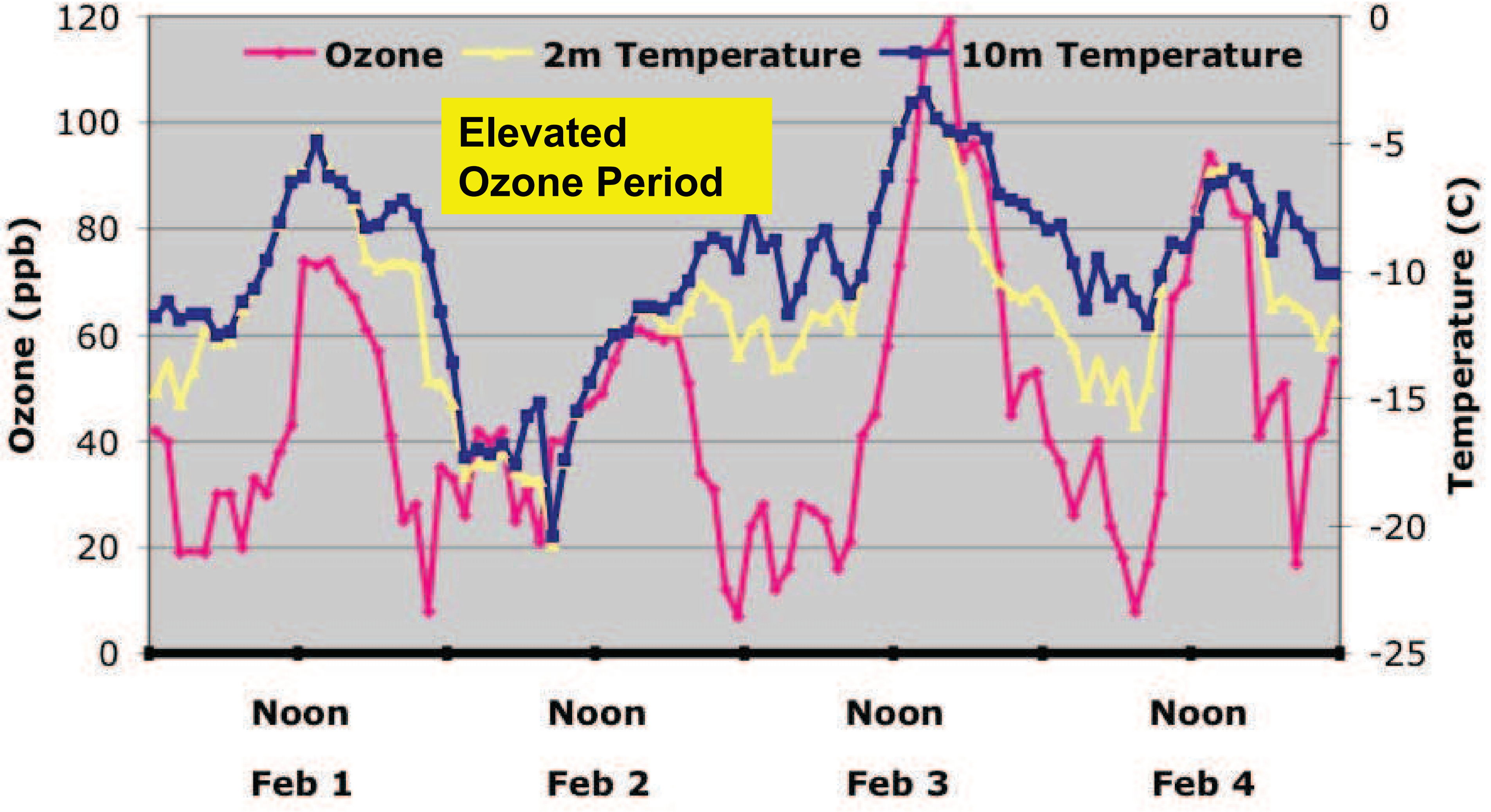


Elevated Ozone Period

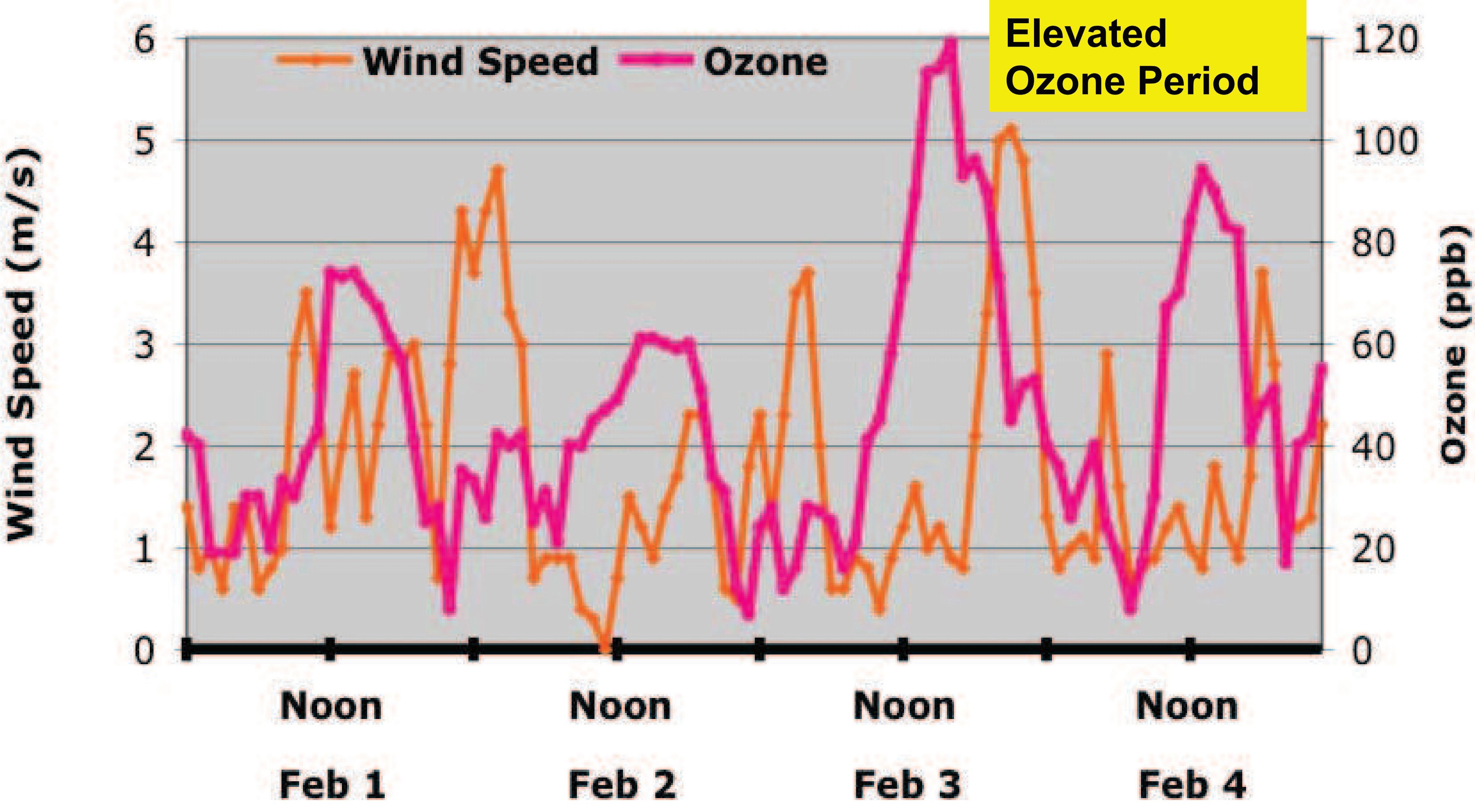
Ozone and NOx, Jonah, February 1-4, 2005



Ozone and Temperature, Jonah, February 1-4, 2005

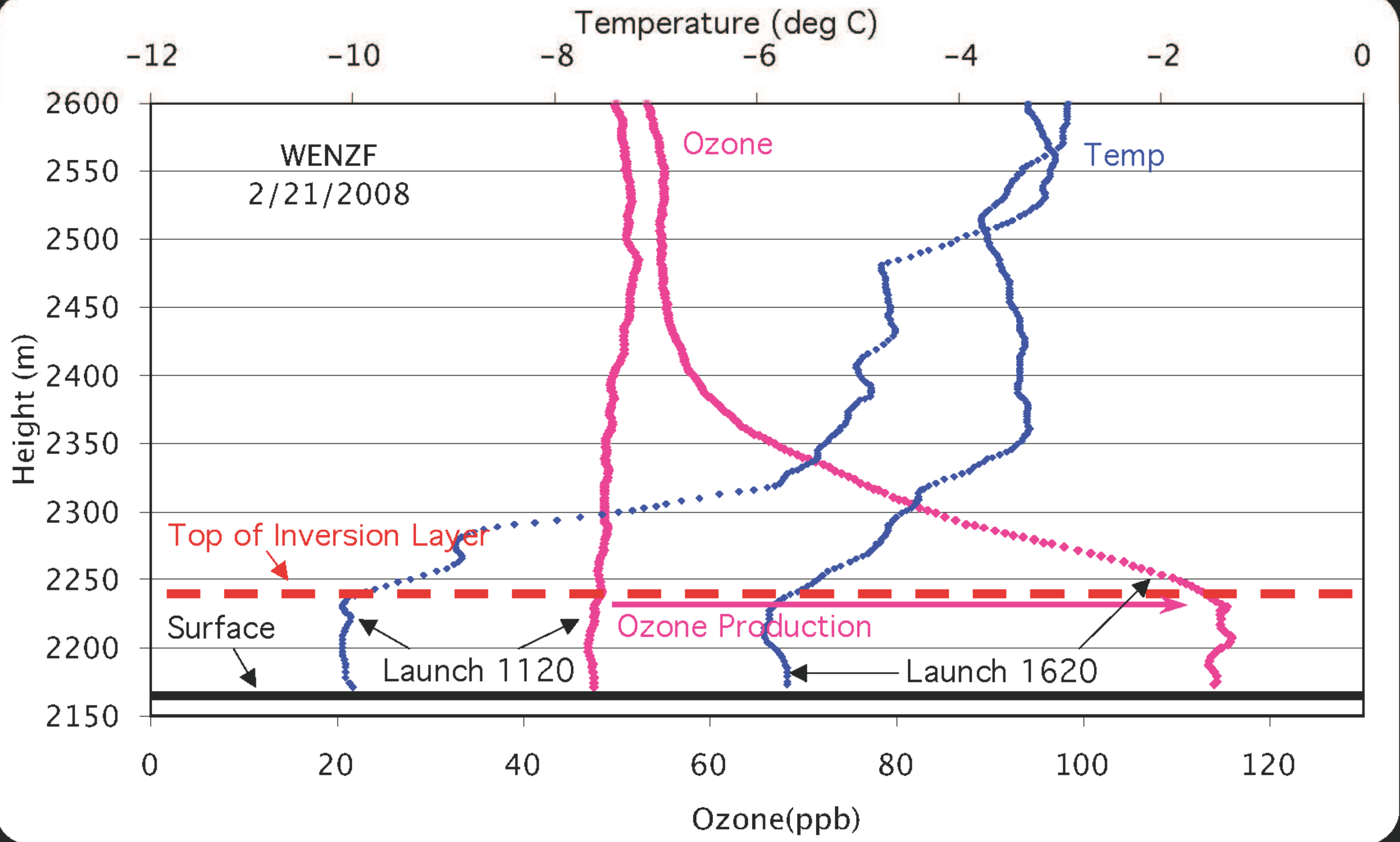


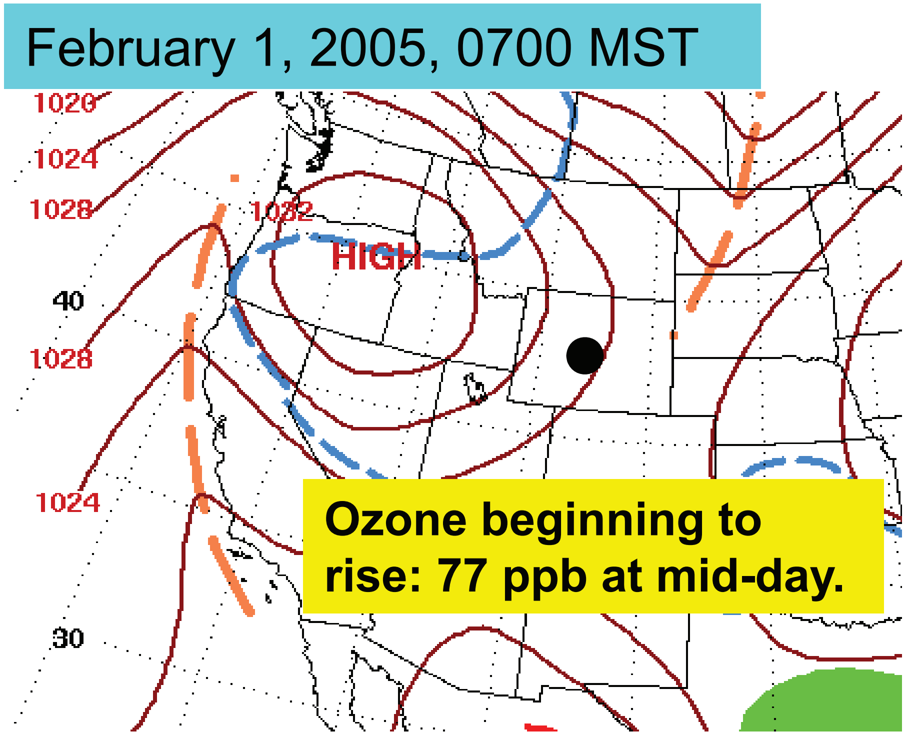
Ozone and Wind Speeds, Jonah, WY, Feb 1-4, 2005



Elevated Ozone Period

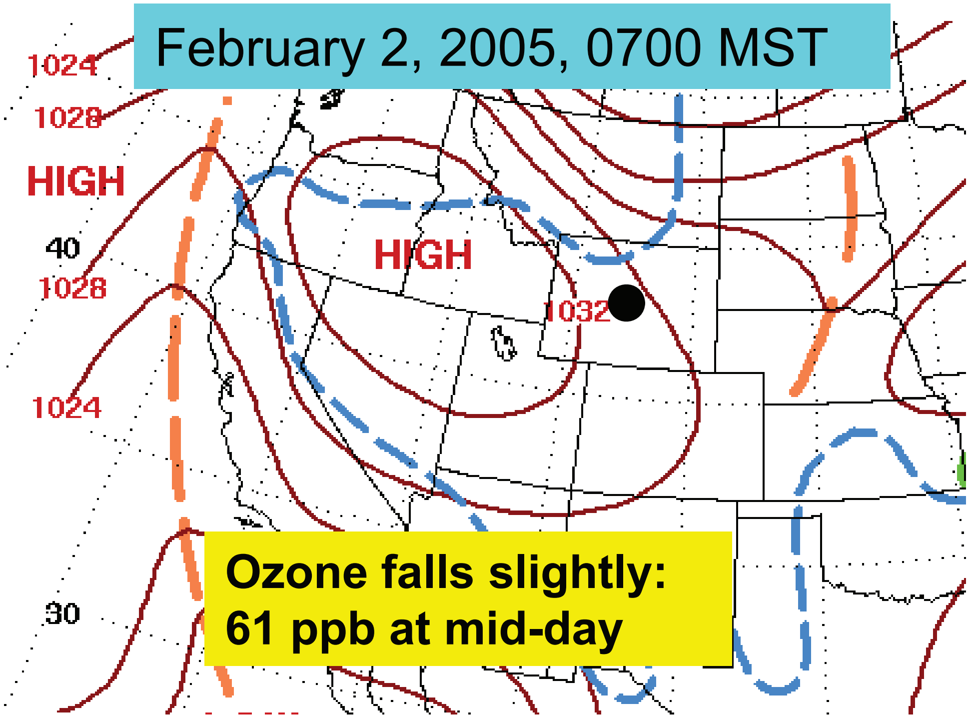
Ozonesondes





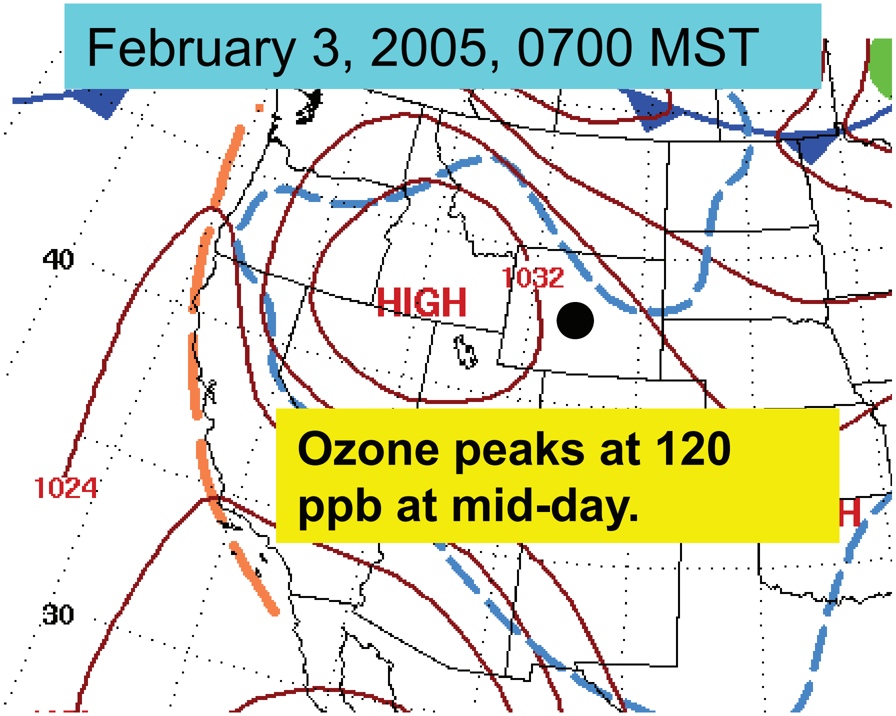
February 1, 2005, 0700 MST

Ozone beginning to rise: 77 ppb at mid-day.



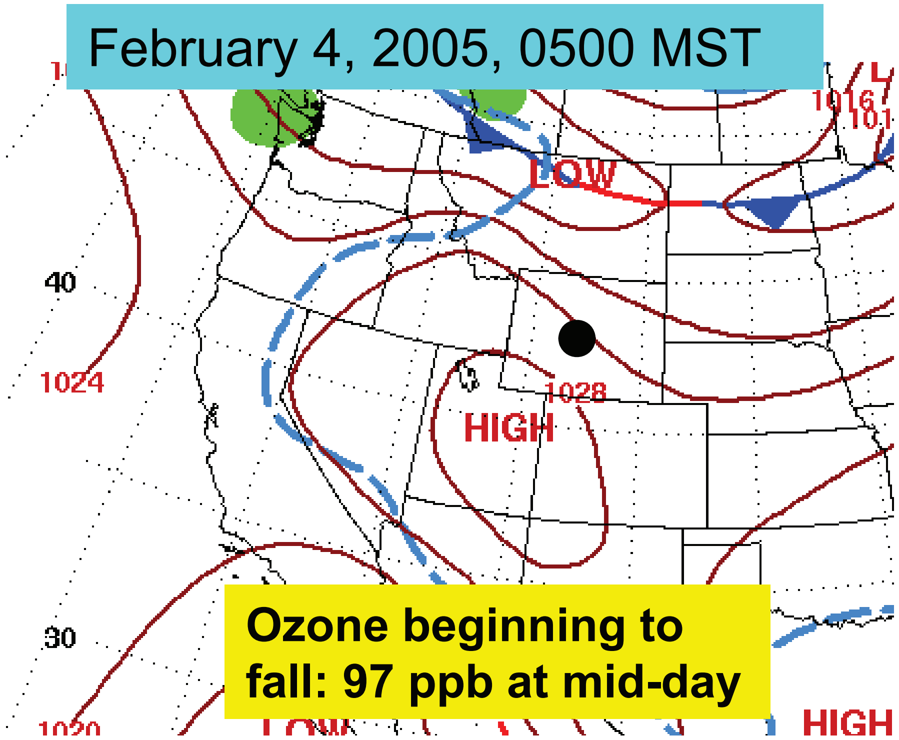
February 2, 2005, 0700 MST

Ozone falls slightly: 61 ppb at mid-day



February 3, 2005, 0700 MST

Ozone peaks at 120 ppb at mid-day.



February 4, 2005, 0500 MST

Ozone beginning to fall: 97 ppb at mid-day

Economics Of The Jonah Gas Field

- The 30,000 acre Jonah gas field, 30 miles south of Pinedale, Wyoming, is estimated to hold 10 trillion cubic feet of natural gas.
- The field presently produces enough gas to serve 3,000,000 U.S. homes per year.
- In 2007, the Jonah Field produced natural gas revenues in excess of $8 billion.
- The value of the gas to be extracted from the field over 40 years is calculated to be in excess of $60 billion (2005 prices).

Thank You for Hanging In Until the END!

DAVE FREUDENTHAL
GOVERNOR

THE STATE OF WYOMING

STATE CAPITOL
CHEYENNE, WY 82002

Office of the Governor

March 12, 2009

Ms. Carol Rushin
Acting Regional Administrator
USEPA Region 8
Mail Code: 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

RE: Wyoming 8-Hour Ozone Designation Recommendation

Dear Ms. Rushin:

This letter transmits my recommendations, as allowed for under Section 107(d)(1) of the Clean Air Act, for Wyoming area designations and nonattainment area boundaries for the new eight-hour ozone National Ambient Air Quality Standards. These recommendations are based on a Wyoming Department of Environmental Quality (WDEQ) staff analysis which follows EPA's guidance dated December 4, 2008, "Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards."

At this time, I am recommending that all areas of the State of Wyoming be designated as attainment/unclassifiable with respect to the 8-hour ozone standard except for Sublette County and partial sections of Sweetwater and Lincoln counties. Enclosed with this letter is a table listing all specific areas of the state with their corresponding recommended designations, along with a figure showing the boundary of the nonattainment area, and ozone monitoring data collected through 2008.[1] The technical support document, which includes a 9-Factor Analysis, is being sent by the Director of the Department of Environmental Quality under separate cover.

Elevated ozone in a truly rural environment when temperatures are well below freezing is an uncommon event. As we move forward to solve this problem, we are uniquely challenged by the lack of tools available to understand and predict ozone formation in the winter in a valley flanked by the Wind River Mountains.

The State of Wyoming is also challenged by the need to reduce emissions from the natural gas industry which has not traditionally been regulated for ozone nonattainment problems. While the EPA has a long list of control strategies to apply in nonattainment areas, very few of them will

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[1] The recommendation does not extend to lands under the jurisdiction of Tribal Authority.

help to reduce ozone in Sublette County. Lowest Achievable Emissions Rate (LAER), Reasonably Available Control Technology (RACT), major source offsets, transportation control measures, and clean fuels programs are designed to reduce emissions from very large industrial sources and urban traffic which are not present in rural Wyoming. Therefore, the WDEQ has already identified the sources that require controls such as drill rigs, pneumatic pumps, dehydration units, and small heaters.

The State is not waiting for the nonattainment process to unfold to tackle the problem, but is addressing the issue on several fronts:

- Several significant field studies have been initiated to understand the processes leading to the occurrence of high ozone levels and to precisely define meteorological conditions that exist when these ozone events occur. These field operations began in 2007 and have continued through the winter of 2009.

- The AQD has deployed more Federal Reference Monitors in southwest Wyoming.

- DEQ is working with contractors to develop models to replicate the high wintertime ozone concentrations observed in the Upper Green.

- The University of Wyoming is conducting an ozone and precursor sampling program in 2009 to provide an independent perspective and further information on spatial variability of ozone in the Basin.

- The DEQ, the Wyoming Department of Health and the Sublette County Commissioners are working together to assess public health risks posed by air toxics associated with natural gas development. A study is now underway.

- The Air Quality Division has moved aggressively to reduce air pollution by applying BACT to all well sites in the Jonah and Pinedale Anticline gas fields, as well as a minor source offset permitting program. To my knowledge, there isn't another place in the world with this much attention given to permitting natural gas emission points.

I share the outline of our aggressive program for two reasons. First, we believe that the area designations should be based on the technical information painstakingly developed by the DEQ for a unique ozone nonattainment problem. If the EPA uses standard analytic tools appropriate for summertime ozone formation in large metropolitan areas, EPA will reach the wrong conclusions about what causes ozone in Sublette County and how to fix it.

Secondly, I understand that a nonattainment designation includes requirements to reduce air pollution from existing sources. Many local gas producers, working in cooperation with our DEQ, have aggressively reduced air emissions and those reductions will continue even as our natural gas resources continue to be developed. These air emission reductions have occurred because of the application of Wyoming's stringent air pollution permitting requirements; because of industry response to our calls for voluntary emission reductions; and because of Wyoming's insistence on stringent air pollution mitigation requirements in the Jonah Infill and Pinedale Anticline Records of Decision. We have not waited for the federal declaration of nonattainment to solve our air pollution problems, and I do not want a nonattainment designation by EPA to penalize the State for instituting early emission reductions.

While we have submitted recommendations as required under the Act, I envision that much work remains. I would like to propose that my staff at DEQ work with US EPA Region 8 to formalize an approach to share technical information and consult over choices of the baseline EI, the size of the nonattainment area and the resulting classification. Should you have any questions or concerns regarding this matter, please contact Mr. John Corra (307-777-7192) or Mr. Dave Finley (307-777-3746).

Best regards,

Dave Freudenthal
Governor

Enclosures: Attachment 1 - Designation Areas
Attachment 2 - Boundary of Designation Area (Figure)
Attachment 3 - Ozone Monitoring Data

cc: John Corra, DEQ Director
David Finley, AQD Administrator
Lori Bocchino, AQD
Christine Anderson, AQD
Callie Videtich, Director, Air and Radiation Program, EPA Region 8 w/ Enclosures
Monica Morales, EPA Region 8 w/ Enclosures
Kerri Fiedler, EPA Region 8 w/ Enclosures

Attachment 1

2008 Primary and Secondary NAAQS 8-hour Primary and Secondary Ozone Standard
Wyoming Recommendations for Ozone Designations
For areas not under the jurisdiction of Tribal Authority

Region	8-hour Ozone Designation
Casper, WY: Natrona County (part).. The portion within the City of Casper	Attainment/Unclassifiable
Cheyenne, WY: Laramie County (part) .... The portion within the City of Cheyenne	Attainment/Unclassifiable
Evanston, WY: Uinta County (part).. The portion within the City of Evanston	Attainment/Unclassifiable
Gillette, WY: Campbell County (part) .... The portion within the City of Gillette	Attainment/Unclassifiable
Jackson, WY: Teton County (part) .... The portion within the City of Jackson	Attainment/Unclassifiable
Lander, WY: Fremont County (part) .... The portion within the City of Lander	Attainment/Unclassifiable
Laramie, WY: Albany County (part)... The portion within the City of Laramie	Attainment/Unclassifiable
Riverton, WY: Fremont County (part) .... The portion within the City of Riverton	Attainment/Unclassifiable
Rock Springs, WY Sweetwater County (part) .... The portion within the City of Rock Springs	Attainment/Unclassifiable
Sheridan, WY Sheridan County (part) .... The portion within the City of Sheridan	Attainment/Unclassifiable
Albany County (remainder)	Attainment/Unclassifiable
Big Horn County	Attainment/Unclassifiable
Campbell County (remainder)	Attainment/Unclassifiable
Carbon County	Attainment/Unclassifiable
Converse County	Attainment/Unclassifiable
Crook County	Attainment/Unclassifiable
Fremont County (remainder)	Attainment/Unclassifiable
Goshen County	Attainment/Unclassifiable
Hot Springs County	Attainment/Unclassifiable
Johnson County	Attainment/Unclassifiable
Laramie County (remainder)	Attainment/Unclassifiable
Lincoln County (remainder)	Attainment/Unclassifiable
Natrona County (remainder)	Attainment/Unclassifiable
Niobrara County	Attainment/Unclassifiable
Park County	Attainment/Unclassifiable
Platte County	Attainment/Unclassifiable
Sheridan County (remainder)	Attainment/Unclassifiable
Sweetwater County (remainder)	Attainment/Unclassifiable
Teton County (remainder)	Attainment/Unclassifiable
Uinta County (remainder)	Attainment/Unclassifiable

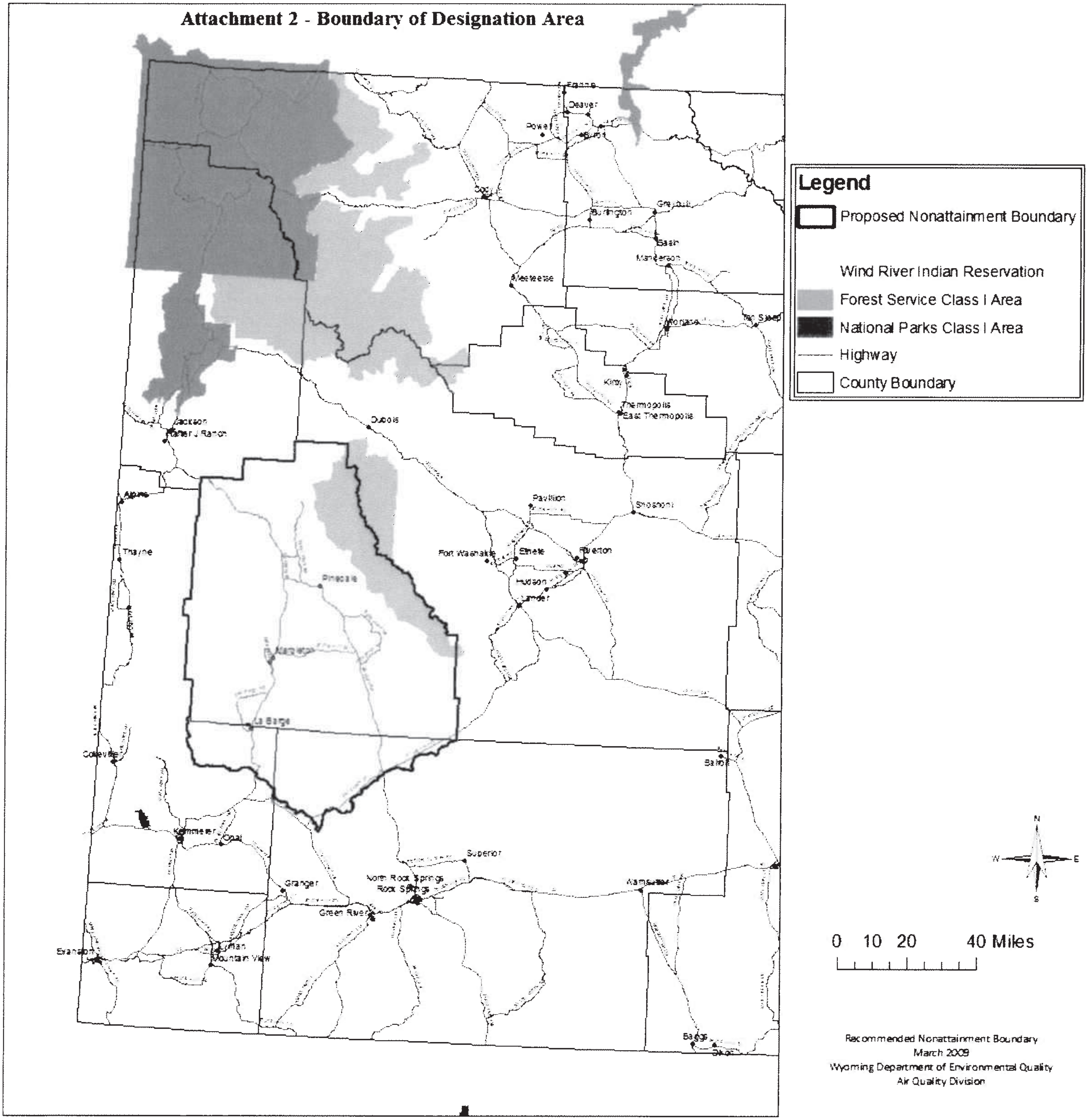
Attachment 1

2008 Primary and Secondary NAAQS 8-hour Primary and Secondary Ozone Standard
Wyoming Recommendations for Ozone Designations
For areas not under the jurisdiction of Tribal Authority
Page 2

Region	8-hour Ozone Designation
Washakie County	Attainment/Unclassifiable
Weston County	Attainment/Unclassifiable
Upper Green River Basin Area: Sublette County: (all) Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range (R) 115 West Township (T) 27N and the northwest corner of Section 31 R 115 West T 27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to the Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N, Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24 N Section 31 crosses into Sweetwater County. Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W R22 N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast long the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T 26North. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T 26North, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.	Non-attainment

R Range, T - Township, N - North, W - West

Attachment 2 - Boundary of Designation Area



Recommended Nonattainment Boundary
March 2009
Wyoming Department of Environmental Quality
Air Quality Division

Attachment 3

Design Values for Wyoming Ambient Ozone Monitors							
Site Name	AQS ID	Year				3-Year Average 2005-2007 (ppm)	3-Year Average 2006-2008[1] (ppm)
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1-Q3[1] (ppm)		
Daniel South	56-035-0100	0.067[2]	0.075	0.067	0.074	N/A	0.072[1]
Boulder	56-035-0099	0.080[3]	0.073	0.067	0.101	0.073[3]	0.080[1]
Jonah	56-035-0098	0.076	0.070	0.069	0.082	0.072	0.074[1]
Yellowstone (NPS)	56-039-1011	0.060	0.069	0.064	0.065	0.064	0.066[1]
Thunder Basin	56-005-0123	0.063	0.072	0.072	0.074	0.069	0.073[1]
Campbell County	56-005-0456	0.063[4]	0.065	0.072	0.060	0.067[4]	0.066[1]

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in July 2005
[3] Incomplete year; began operation in February 2005
[4] One quarter with less than 75% data completeness

4th Maximum 8-Hour Ozone Values for Ambient Monitors without 3 years of data					
Site Name	AQS ID	Year			
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1-Q3[1] (ppm)
Murphy Ridge	56-041-0101	---	---	0.070	0.061
South Pass	56-013-0099	---	---	0.071[2]	0.065
OCI[3]	56-037-0898	---	0.071[3]	0.066	0.072
Wamsutter	56-005-0123	---	0.067[4]	0.064	0.064
Atlantic Rim	56-007-0099	---	---	0.047[5]	0.064

[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in March 2007
[3] Site operated by industry. Incomplete year; began operation in May 2006
[4] Incomplete year; began operation in March 2006
[5] Incomplete year; began operation in October 2007

STATE OF WYOMING

Technical Support Document I For Recommended 8-Hour Ozone Designation For the Upper Green River Basin, WY

March 26, 2009

The Wyoming Department of Environmental Quality
Air Quality Division
Herschler Building, 122 West 25th Street
Cheyenne, Wyoming 82002

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EXECUTIVE SUMMARY

In March 2008 the US EPA promulgated a new National Ambient Air Quality Standard (NAAQS) for ozone. The new standard was lowered from 0.08 ppm to 0.075 ppm based on the fourth highest 8-hour average value per year at a site, averaged over three years. Based on monitoring results from 2006 through 2008, the entire state of Wyoming is in compliance with this standard except for at a single monitor, the Boulder monitor, in Sublette County.

The Wyoming Department of Environmental Quality, Air Quality Division (AQD) evaluated whether a nonattainment area should be designated due to the monitored results at the Boulder monitor. Using EPA's guidance in the Robert J. Meyers December 4, 2008 memo, the AQD performed a nine-factor analysis, which is the basis of this document. This analysis supports AQD's recommendation that the Upper Green River Basin (UGRB), as defined in the introduction to this document, be designated as nonattainment for the 2008 ozone NAAQS.

The AQD bases this recommendation on a careful review of the circumstances surrounding the incidence of elevated ozone events. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005. Our determination of an appropriate nonattainment area boundary is focused on an evaluation of EPA's nine factors, applied to the first quarter of the year. It is important to evaluate conditions during the first quarter of the year in order to focus on the very specific set of circumstances that lead to high ozone.

The most compelling reasons for the boundary recommendation are based on the meteorological conditions in place during and just prior to elevated ozone events. Elevated ozone episodes occurred in 2005, 2006 and 2008; they were associated with very light low-level winds, sunshine, and snow cover, in conjunction with a strong low-level surface-based temperature or "capping" inversion. The longest such event (February 19-23, 2008), which also resulted in the highest measured ozone of 122 ppb as an 8-hour average at the Boulder station, has been reviewed in detail and summarized in Section 7 of this document. Section 7 demonstrates that sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of an inversion and very low wind speeds, which significantly limit precursor and ozone transport from sources located outside of the UGRB.

The AQD carefully examined sources of ozone and ozone precursors within Sublette and surrounding counties. When evaluating sources, AQD considered these five of EPA's factors: population density, traffic and commuting patterns, growth rates and patterns, emission data, and level of control of air emissions. Sublette County is a rural county with a population density of two people per square mile; the most densely populated nearby county (Uinta) is also largely rural with a population density of ten people per square mile. As would be expected, the number of commuters into or out of the UGRB is small and does not represent a significant source of precursor emissions. While there is an interstate highway 80 miles south of the Boulder monitor, the attached analysis demonstrates that I-80 traffic is not considered to be a significant contributor of emissions that impact the Boulder monitor during ozone events.

Although population and population growth was not a significant factor, growth in the oil and gas (O&G) industry in Sublette County was considered pertinent. The volume of natural gas produced doubled between 2000 and 2008 in the county; the number of wells completed doubled between 2004 and 2008. Approximately 1,500 well completions were recorded in Sublette County in the last four years. Growth in the oil and gas industry in nearby areas is much slower.

AQD prepared an estimated inventory of emissions for the recommended nonattainment area and the surrounding counties. The inventory showed that approximately 94% of VOC emissions in the UGRB and 60% of NOx emissions are attributable to oil and gas production and development. Of the eleven major sources in the UGRB, all are O&G related. To the north, east and west there are few major sources in counties adjacent to the UGRB. In addition to the major sources, there are numerous minor sources in the UGRB including several concentrated areas of O&G development. Just to the south of the UGRB, there are a few major sources, several minor sources and again, a concentrated area of O&G wells. AQD then used other factors, meteorology, topography, and level of control of emissions, to determine which of the sources to the south of Sublette County should be included in the proposed nonattainment boundary.

The level of control of emissions in the Jonah and Pinedale Anticline Development is very stringent and new oil and gas production units in Sublette County and surrounding counties require permits including Best Available Control Technology (BACT). An interim policy for Sublette County which took effect in 2008 results in a net decrease in emissions of ozone precursors with every permit that is issued. Since stricter controls for O&G are already in place in Sublette County, if O&G sources outside of Sublette County might contribute ozone or ozone precursors to the Boulder monitor, including these O&G sources in the proposed nonattainment area would provide motivation to control these sources.

In evaluating topography, the east, north and west county boundaries are natural boundaries of high mountains. These geographical and jurisdictional boundaries also coincide with population boundaries and emission source boundaries. To the south, the topographical boundaries are less dramatic, but there are rivers, valleys, and buttes that form geographic boundaries near the southern border of Sublette County. Therefore, the AQD considered the county boundary to the north, east and west to be a reasonable boundary based on geography, jurisdictions, emission sources, population and growth.

However, meteorology provided the strongest basis for setting the southern boundary of the proposed nonattainment area. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005.

Meteorological conditions in place during and just prior to elevated ozone events provide the most specific data for setting the south boundary. Elevated ozone episodes are associated with very light low-level winds, cold temperatures, sunshine, and snow cover, in conjunction with strong low-level surface-based temperature inversions. Sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of an inversion and the very low wind speeds, which influence the transport of emissions. Detailed meteorological data collected during intensive field studies shows that emissions from sources south of the recommended nonattainment area are generally carried toward the east and not into the UGRB during or just prior to an ozone episode. Speciated VOC data collected in the UGRB during elevated ozone episodes also has a dominant oil and gas signature, indicating the VOC concentrations are largely due to O&G development activities.

Meteorology and topography indicate that sources outside a southern boundary defined by the Little Sand Creek and Pacific Creek to the east and the Green River and Fontenelle Creek to the west do not contribute to ozone and ozone precursors which could affect the Boulder monitor.

The analysis conclusively shows that elevated ozone at the Boulder monitor is primarily due to local emissions from oil and gas (O&G) development activities: drilling, production, storage, transport, and treating. The ozone exceedances only occur when winds are low indicating that there is no transport of ozone or precursors from distances outside the proposed nonattainment area. The ozone exceedances only occur in the winter when the following conditions are present: strong temperature inversions, low winds, cold temperatures, clear skies and snow cover. If transport from outside the proposed nonattainment area was contributing to the exceedances, then elevated ozone would be expected at other times of the year. Mountain ranges with peaks over 10,000 feet border the area to the west, north and east influence the local wind patterns. Emission sources in nearby counties are not upwind of the Boulder monitor during episodes which exceed the 8-hour ozone standard in Sublette County.

The proposed nonattainment area boundary includes the violating monitor and the sources which are most likely to contribute ozone and ozone precursors to the monitored area. Using this as a boundary will allow the State to focus its resources on the emission sources that contribute to the ozone issue and will allow the State to control the ozone problem in a timely manner.

INTRODUCTION

BACKGROUND AND REGULATORY HISTORY

The U.S. Environmental Protection Agency (EPA) is charged with developing air quality standards for the protection of human health and welfare. EPA is also required to periodically evaluate those standards and revise them if scientific analyses indicate different standards would be more protective of public health and welfare. In March of 2008, EPA promulgated a new National Ambient Air Quality Standard (NAAQS) for ozone. This new standard lowered the 8-hour level of ozone from 0.08 parts per million (ppm) to 0.075 ppm, based on the fourth maximum 8-hour value at a site averaged over three years. Each state must recommend ozone designations no later than March 12, 2009 and final designations must be complete by March 12, 2010.

BASIS FOR TECHNICAL SUPPORT

This technical support document considers nine criteria, or “factors” to make a recommendation for the appropriate location and boundary of a nonattainment area. Those factors are derived from EPA’s memorandum issued December 4, 2008, “Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards.” States must submit an analysis of these nine factors, along with a proposed nonattainment boundary, for any areas that are not meeting the federal standard. The nine factors that must be addressed are:

Air quality data

Emissions data (location of sources and contribution to ozone concentrations)

Population density and degree of urbanization (including commercial development)

Traffic and commuting patterns

Growth rates and patterns

Meteorology (weather/transport patterns)

Geography/topography (mountain ranges or other air basin boundaries)

Jurisdictional boundaries (e.g., counties, air districts, existing nonattainment areas, Reservations, metropolitan planning organizations (MPOs))

Level of control of air emissions

RECOMMENDED NONATTAINMENT AREA BOUNDARY

The State of Wyoming recommends that the UGRB, with boundaries described as follows, be designated as a nonattainment area for the 2008 8-hour ozone standard:

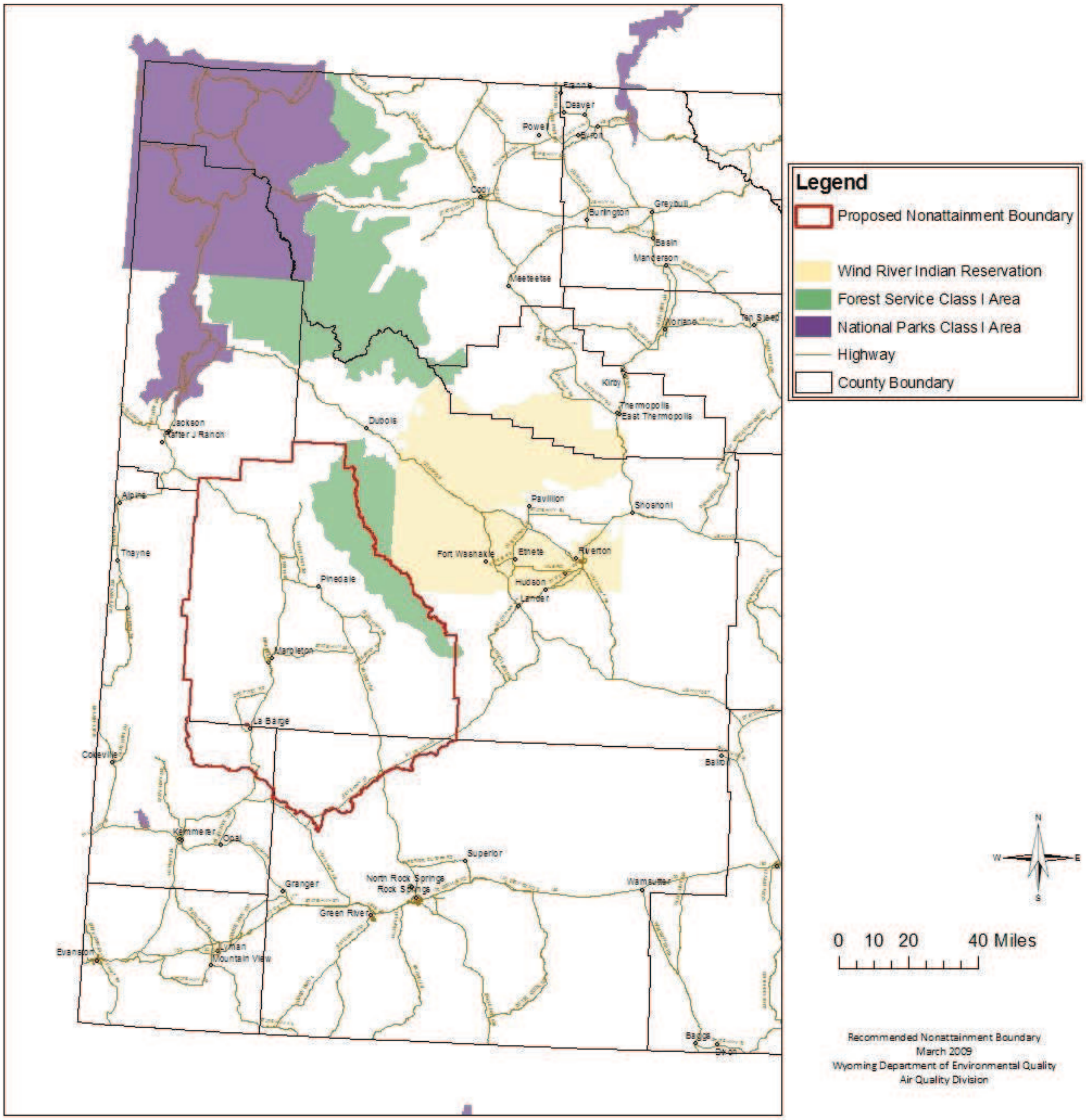
Sublette County: (all)

Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range

(R) 115 West Township (T) 27N and the northwest corner of Section 31 R 115 West T 27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N, Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24 N Section 31 crosses into Sweetwater County.

Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W R22 N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast along the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T 26North. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T 26North, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.

A picture of this area follows.



Recommended Nonattainment Boundary
March 2009
Wyoming Department of Environmental Quality
Air Quality Division

KEY ISSUES

Elevated ozone concentrations in most areas occur during the warm summer months, when there is abundant solar radiation and high temperatures. The elevated ozone concentrations at the Boulder monitor in Sublette County occur in late winter and early spring when sun angles are low so there is less solar radiation and temperatures are below freezing. Ozone formation at the Boulder monitor in Sublette County does not follow the pattern of ozone formation found in urban areas in the summer.

Moderately elevated ozone was first detected in Sublette County in February of 2005 and 2006. The Wyoming Air Quality Division (AQD) conducted intensive meteorological and ambient data collection and analyses in 2007 and 2008 in order to understand this phenomenon. AQD is continuing this effort in 2009. Although analysis of all the data is not complete, AQD has already determined that:

- Local meteorological conditions are the single most important factor contributing to the formation of ozone and the definition of the nonattainment boundary.
- Meteorological models that utilize only regional data will not correctly attribute ozone and ozone precursors to the sources which affect the UGRB.
- Trajectory analyses using detailed observation-based wind field data show that local scale transport of ozone and ozone precursors is dominant during periods of elevated ozone.
- Trajectory analyses using the wind field data show that regional transport of ozone and ozone precursors appears to be insignificant during periods of elevated ozone.

SECTION 1
AIR QUALITY DATA

SYNOPSIS

Ozone at levels exceeding the standard has been monitored at one of three stations in the UGRB – specifically, the Boulder monitor.

Measured ozone levels have not exceeded the standard in the counties adjacent to the UGRB.

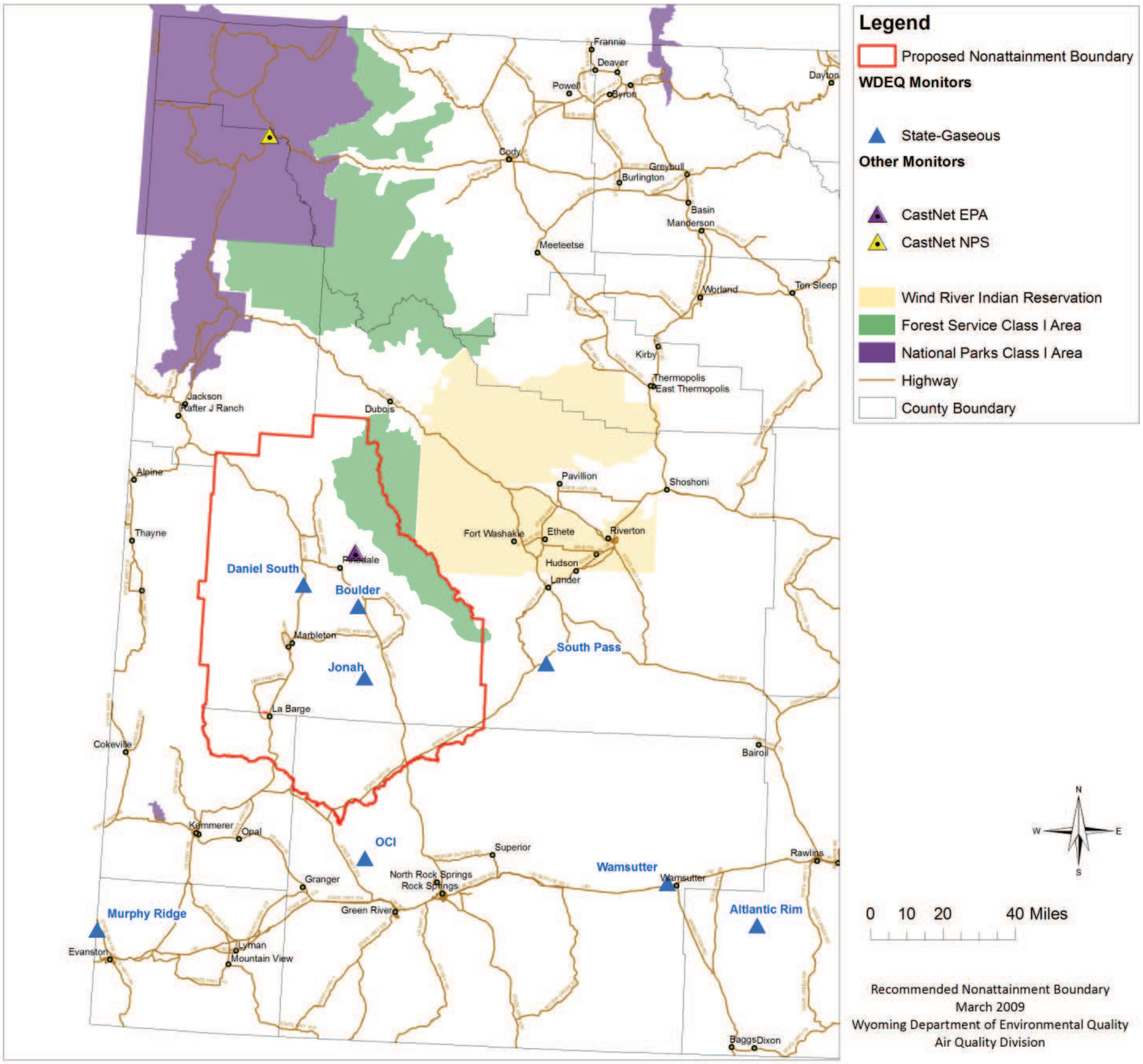
Elevated ozone within the UGRB typically only occurs in January, February, or March.

VOCs detected in ambient air in the UGRB have a strong oil and gas signature.

ANALYSIS

The Wyoming Air Quality Division (AQD) operated three monitoring stations in the proposed nonattainment area in 2005-2008. Monitor locations are shown on the map in Figure S.1-1. This map also shows the location of monitors in adjacent counties.

FIGURE S.1-1: **Map Showing Monitoring Stations In and Near the Upper Green River Basin**



Recommended Nonattainment Boundary
March 2009
Wyoming Department of Environmental Quality
Air Quality Division

Table S.1-1 shows the ozone design values for the 8-hour standard for the Reference or Equivalent Method monitoring stations shown in Figure S.1-1. All data are collected by Reference or Equivalent Method monitors and meet EPA's criteria for quality and completeness unless otherwise noted. Please note, Pinedale CASTNet data are not included in the design values because this station was not operated in accordance with Part 58 QA requirements until 2007. The design value is the three-year average of the annual fourth highest daily maximum 8-hour ozone concentration (a calculated value less than or equal to 0.075 ppm indicates attainment of the standard; a calculated value of greater than 0.075 ppm is a violation of the standard). Table S.1-2 shows monitored data from other Federal Reference Method (FRM) or Federal Equivalent Method (FEM) ozone monitors in the counties surrounding the UGRB. These monitors have been running for less than 3 years and therefore do not have a design value calculated.

Table S.1-1: Design Values for Monitors In or Near the Upper Green River Basin

Site Name	AQS ID	Year				3-Year Average 2005-2007 (ppm)	3-Year Average 2006-2008[1] (ppm)
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1 – Q3 (ppm)		
Daniel South	56-035-0100	0.067[2]	0.075	0.067	0.074	N/A	0.072[1]
Boulder	56-035-0099	0.080[3]	0.073	0.067	0.101	0.073[3]	0.080[1]
Jonah	56-035-0098	0.076	0.070	0.069	0.082	0.072	0.074[1]
Yellowstone (NPS)	56-039-1011	0.060	0.069	0.064	0.065	0.064	0.066

[1] Data collected and validated through 3rd quarter 2008

[2] Incomplete year; began operation in July 2005

[3] Incomplete year; began operation in February 2005

Table S.1-2: 4th Maximum 8-Hour Ozone Values for Monitoring in Surrounding Counties

Site Name	AQS ID	Year			
		2005 (ppm)	2006 (ppm)	2007 (ppm)	2008 Q1 – Q3 (ppm)
Murphy Ridge	56-041-0101	---	---	0.070	0.061[1]
South Pass	56-013-0099	---	---	0.071[2]	0.065[1]
OCI[3]	56-037-0898	---	0.071[3]	0.066	0.072[1]
Wamsutter	56-005-0123	---	0.067[4]	0.064	0.064[1]
Atlantic Rim	56-007-0099	---	---	0.047[5]	0.064[1]

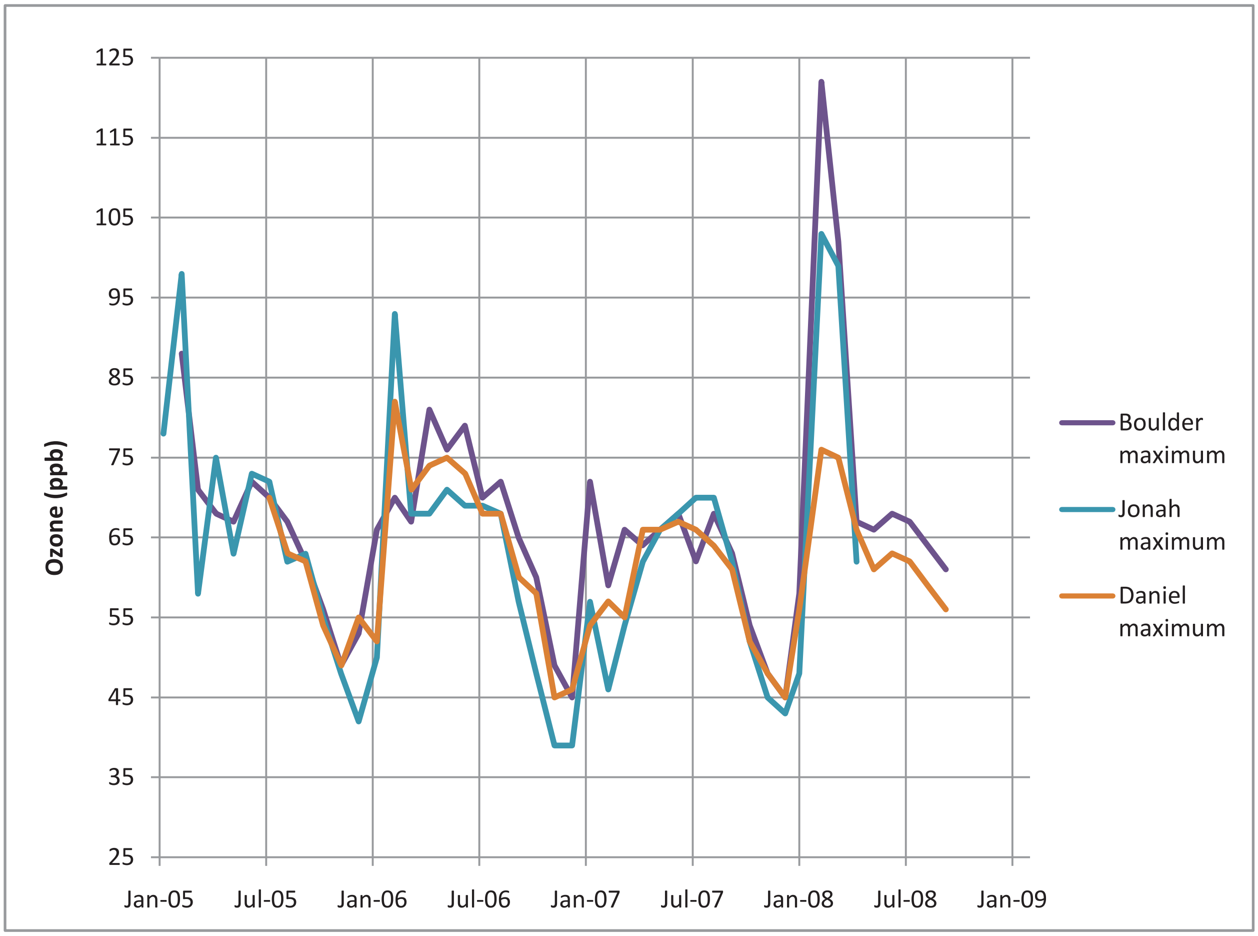
[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in March 2007
[3] Site operated by industry. Incomplete year; began operation in May 2006
[4] Incomplete year; began operation in March 2006
[5] Incomplete year; began operation in October 2007

Using only data from 2005 through 2007, the monitors for which a design value can be calculated indicate compliance with the ozone NAAQS. Year-to-date data from 2008, however, bring the 2006 - 2008 design value for the Boulder monitor to 0.080 ppm (compared to the standard of 0.075).

While monitors in counties adjacent to the UGRB have not been in operation for a full three-year period (with the exception of the Yellowstone NPS monitor), none of them have 4th-high maximum 8-hour ozone values above 0.075 ppm for any year. This would indicate that, based on ambient monitoring data, ozone levels have not been measured that exceed the standard outside of the UGRB (within Wyoming).

When the data from the Boulder monitoring station, the only monitor showing ozone levels in excess of the standard, is reviewed closely, it shows that elevated ozone typically occurs in the winter. This trend is also evident at the two stations nearby (South Daniel and Jonah). Figure S.1-2 shows the daily 8-hour maximum for these stations on a monthly basis over the last four years. This is an unprecedented phenomenon, as ozone was thought to be a summertime problem. The Wyoming DEQ, with the help of industry, has dedicated significant resources to better understand this situation. The studies indicate that elevated ozone occurs in the UGRB under very specific meteorological conditions, described in greater detail in Section 7 of this document. Briefly, these conditions are the presence of a strong temperature inversion in conjunction with low wind speeds, snow cover and clear skies. These conditions have occurred in January, February, and March.

Figure S.1-2: Monthly 8-Hour Maximum Ozone Within the UGRB



AQD performed Winter Ozone Studies in 2007, 2008 and 2009 in the UGRB. The purpose of these studies is to investigate and monitor the mechanisms of ozone formation during the winter months. These data will in turn be used to develop a conceptual model of ozone formation in the UGRB. As the study has progressed, the scope of the study has been refined as AQD has learned about the unique issue of winter ozone formation. In general terms, the scope of the winter ozone studies include:

1. Placing additional FEM and non-FEM (2B ozone analyzers) monitors throughout the UGRB to characterize spatial and temporal distribution of ground-level ozone.
2. Placing additional three-meter meteorological towers (mesonet) throughout the UGRB to characterize local micro-scale meteorology.
3. Placing additional precursor monitoring (e.g., VOC, NOx and CO) in a few sites around the UGRB to characterize precursor concentrations.
4. Flying a plane equipped with continuous ozone and $PM_{2.5}$ around the UGRB to characterize spatial distribution of ozone (above, in, and below the boundary layer).
5. Launching ozone and rawinsondes to characterize vertical meteorology and ozone distribution.

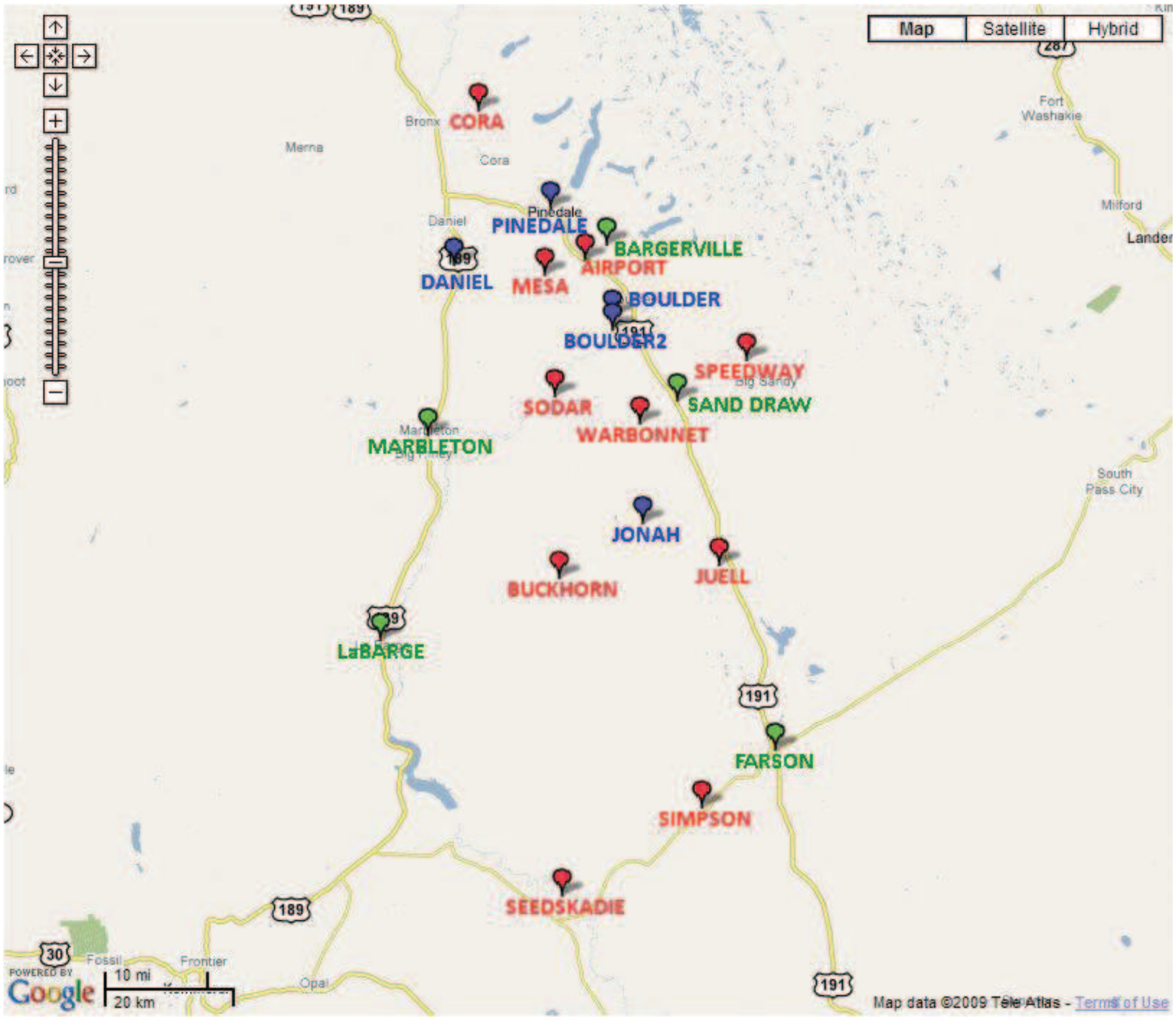
6. Operating ground based upper-air meteorological instruments (e.g., Mini-SODAR, RASS, Wind Profiler) to characterize mixing levels and inversion heights.

In 2007, meteorological conditions did not set up as they had in 2005 and 2006 and elevated ozone did not form in February and March. However, AQD collected data that helped to draw some conclusions about winter ozone formation. The speciated VOC samples collected had a strong oil and gas signature. AQD was able to investigate which detected VOC species were having a greater effect on ozone formation. UV radiation measurements showed that when fresh snow is available, greater than 80% of the ultra-violet light can be reflected.

During the 2008 winter study, several multi-day episodes of elevated ozone were studied. Six additional ozone monitoring locations were added and the plane was flown to provide more information on the spatial and temporal variability around the UGRB. AQD continued to collect speciated VOC samples which confirmed the strong oil and gas signature. These data also allowed us to identify species of interest with respect to elevated ozone formation. AQD also used a mini-SODAR and rawinsondes to characterize the mixing heights and inversion strength on elevated ozone days. It was found that on days with elevated ozone, mixing heights could be as shallow as 50-200 meters above ground level.

For the 2009 winter study, AQD has placed eleven FEM and non-FEM continuous ozone monitors around the UGRB. Additionally, AQD has placed five FEM ozone monitors in communities around the UGRB as part of an Air Toxics study. These monitors compliment the three long-term FEM ozone monitors currently operating. AQD has also added precursor monitoring at the Boulder, Jonah and SODAR stations. Figure S.1-3 shows the current configuration of ozone monitoring in the UGRB.

Figure S.1-3: Winter 2009 Ozone Monitoring in the Upper Green River Basin



While ozone data from these studies cannot be used directly for designation, AQD has used these data to support our recommendation on a nonattainment area boundary for the UGRB. Specifically, VOC data are referenced in Section 2 and mesonet data are used to develop a localized wind field referenced in Section 7. Final reports, quality assurance project plans, and databases from the 2007 and 2008 studies are available on the WDEQ/AQD website: (http://deq.state.wy.us/aqd/Monitoring%20Data.asp). Data from the 2009 study will be posted to the AQD Monitoring page after it has been fully quality assured.

SECTION 2
EMISSIONS DATA

SYNOPSIS

The primary sources of ozone-forming precursors in the recommended nonattainment area are associated with the oil and gas development and production industry in the UGRB.

ANALYSIS

Ground-level ozone is primarily formed from reactions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) in the presence of sunlight. VOCs and NOx are considered "ozone precursors." As part of the nine-factor analysis, the Air Quality Division compiled emission estimates for VOCs and NOx for ten source categories in the proposed nonattainment area as well as counties or portions of counties surrounding the area. This information is summarized in Table S.2-1 and represents preliminary estimated first quarter 2007 emission inventory data for all potential sources. Emissions information for 2007 is used because it is the most recently available data for all source sectors. Only the first quarter is shown because elevated ozone in the UGRB occurs during limited episodes in the first three months of the calendar year. In general, quarterly emissions for the second through fourth quarters of the year are the same as for the first quarter, with the exception that biogenic VOC emissions are expected to be greater in the spring and summer months.

When comparing the raw precursor emission totals in Table S.2-1, AQD is aware that the total for the area defined as "Sweetwater Outside of Upper Green River Basin" is the largest for both VOCs and NOx. However, after carefully reviewing the other eight factors to determine an appropriate boundary, AQD has concluded that there are no violations occurring in Sweetwater County, nor are the emissions sources in most of Sweetwater County contributing meaningfully to the observed violations in Sublette County. AQD will demonstrate in this document that the emissions identified in the UGRB, along with other key factors such as site-specific air quality data (Section 1), unique meteorological and geographical conditions (Sections 6 and 7), as well as extraordinary industrial growth rates (Section 5), will explain the exceedances of the ozone standard at the Boulder monitor in Sublette County.

AQD has taken the next step to focus in on the particular emission sources believed to be contributing to high ozone levels. Figure S.2-1 shows emission inventory data for the UGRB. These emission estimates indicate that the most significant sources of ozone precursors in the UGRB are biogenics and the oil and gas industry.

<u>Biogenics</u>

During the first quarter of the year, biogenic emissions are lower than emissions from the other months of the year. The 2007 and 2008 Upper Green Winter Ozone Study (described in Section 1) analyzed canister samples for four biogenic species: isoprene, a-pinene, b-pinene, and d-limonene. Of particular interest is that isoprene, which is a common and highly reactive species of overwhelmingly biogenic origin, was not detected in any of the samples collected at the Jonah monitor and found only at levels just above the method detection limit in one sample at the Daniel monitor and two samples at the Boulder monitor. A-pinene, b-pinene and a-limonene were detected in 3% or less of the samples at each site. These results are consistent with the expected absence of biogenic VOCs in the study area during the winter months.

Biogenic emissions may be overestimated in the standard models used to prepare Table S.2-1, as typical biogenic species have not been detected in significant quantities in canister samples. Alternatively, they may be attributed to forested areas on the east and west flanks of the recommended nonattainment area, which may not influence air composition at Boulder, Daniel, and Jonah during the episodic ozone conditions when canister samples have been taken.

Oil and Gas Production and Development

Oil and gas production and development is the only significant industry emission source within the UGRB. We have divided the emissions from this industry further into those associated with construction, drilling, and completion of wells; well site production; and major sources. Oil and gas production is the largest source of VOCs, with the second largest being biogenic sources. The largest NOx emission sources are from rigs drilling the natural gas wells, natural gas compressor stations (O&G Major Sources) and gas-fired production equipment.

Figure S.2-2 shows the nonattainment boundary and the location of emission sources within and around the boundary. There are 11 major sources within the proposed boundary. Ten of these are compressor stations and one is a liquids gathering system. The figure also shows the distribution of oil and gas wells in the nonattainment and surrounding area.

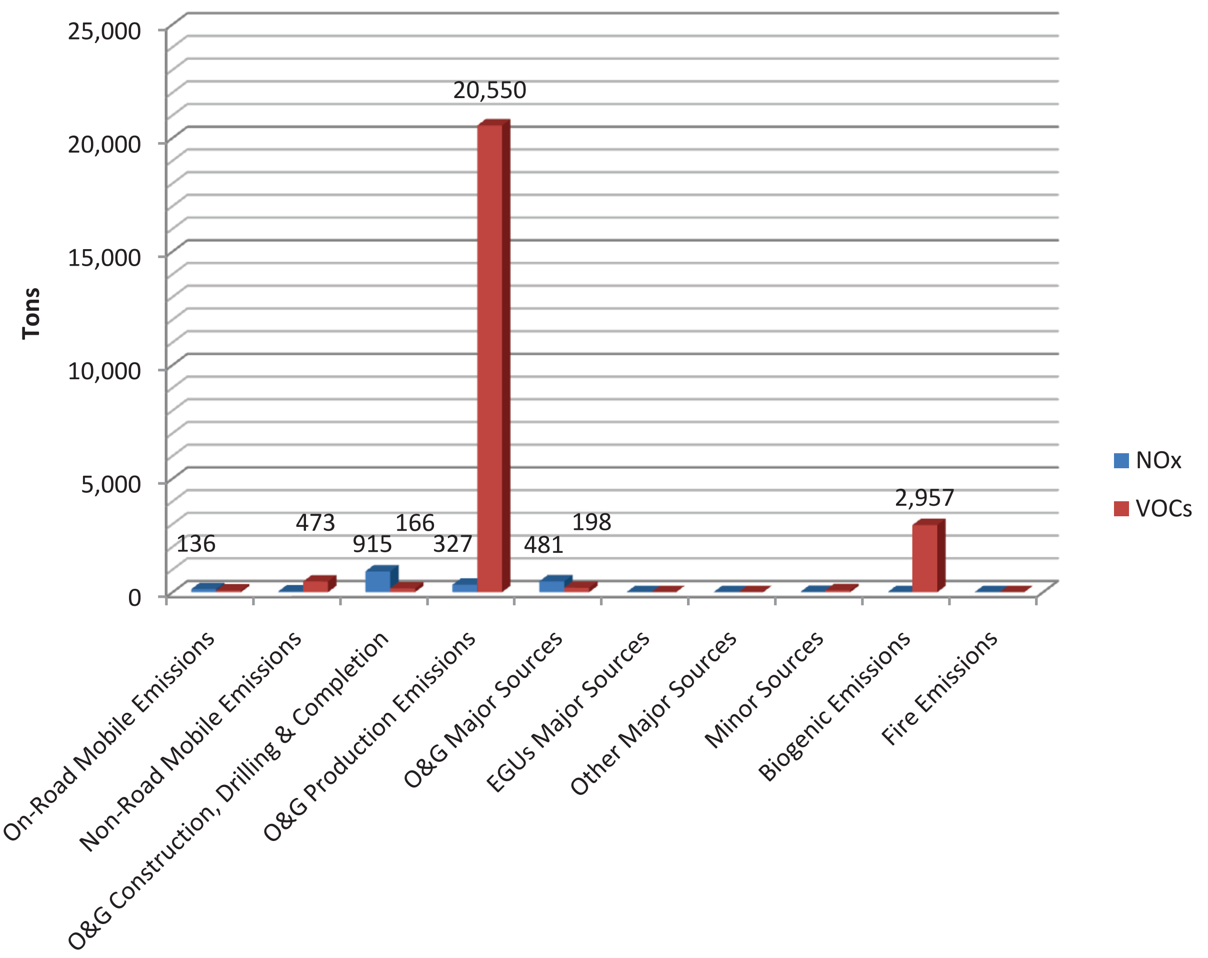
The boundary encompasses areas of oil and gas development and their respective emissions sources, defined by topography (Section 6) and meteorology (Section 7), which are the most likely sources of ozone-forming precursors influencing the Boulder monitor during elevated ozone episodes.

While the Air Quality Division has been studying the emissions from oil and gas production and development for a number of years, it is an extremely complex industry to understand from an air quality perspective. AQD has made a concerted effort to estimate the emissions impacting the monitors during very unusual circumstances. These efforts will continue and AQD has plans to refine these estimates over time.

Table S.2-1: 1st Quarter, 2007 Estimated Emissions Summary (tons)

	Upper Green River Basin		Lincoln Outside of Upper Green River Basin		Sweetwater Outside of Upper Green River Basin		Uinta		Fremont		Teton	
Emissions Sources	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs	NOx	VOCs
On-Road Mobile Emissions	136	79	155	89	1,727	308	655	122	242	138	157	90
Non-Road Mobile Emissions	36	473	593	208	2,000	174	604	157	101	104	34	256
O&G Well Construction, Drilling & Completion	915	166	243	227	747	870	12	13	102	254	0	0
O&G Production Emissions	327	20,550	148	7,074	460	21,232	133	4,095	281	10,005	0	0
O&G Major Sources	481	198	488	63	9,631	2,200	174	196	111	20	0	0
EGUs Major Sources	0	0	3,151	24	6,335	75	0	0	0	0	0	0
Other Major Sources	0	0	0	0	2,445	1,929	0	0	0	0	0	0
Non-O&G Minor Sources	17	86	346	31	171	56	22	60	10	33	3	0
Biogenic Emissions	0	2,957	0	2,376	0	2,184	0	816	0	5,354	0	3,268
Fire Emissions	5	4	0	0	0	0	0	0	317	232	0	0
Total Emissions	**1,917**	**24,514**	**5,124**	**10,092**	**23,516**	**29,027**	**1,600**	**5,458**	**1,163**	**16,142**	**194**	**3,614**

Figure S.2-1: Estimated Upper Green River Basin Emissions
1st Quarter, 2007



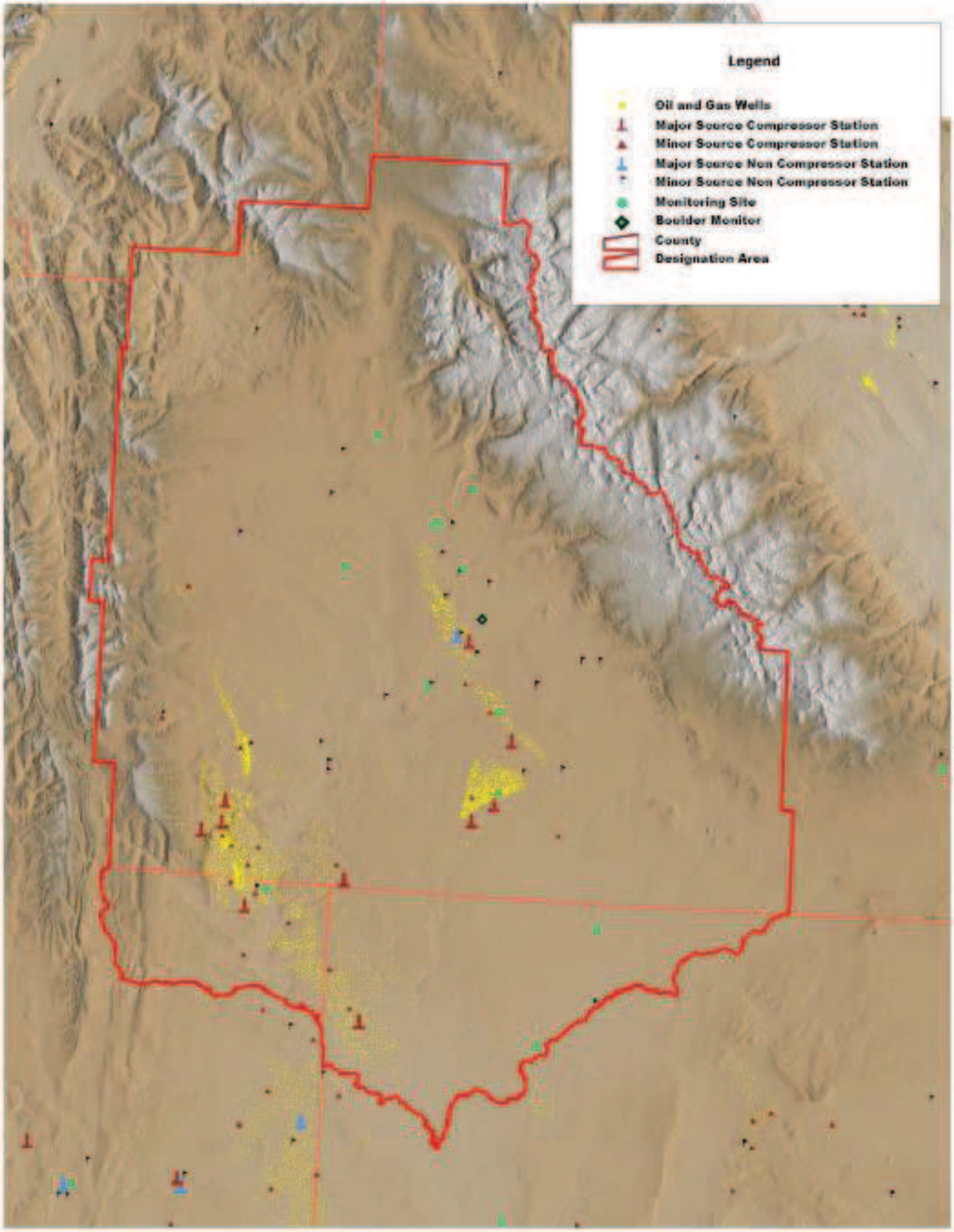


Figure 2.2-2: Designation Area Boundary

SECTION 3
POPULATION DENSITY AND DEGREE OF URBANIZATION

SYNOPSIS

Urbanized areas in surrounding counties do not affect ozone formation or precursors in the proposed nonattainment area just prior to and during elevated ozone episodes, because the urbanized areas are distant and in some cases separated by geographical features such as mountains.

The past and anticipated future rapid population growth is expected to be limited to the proposed nonattainment area, which would suggest that neighboring counties should not be included in the proposed nonattainment area.

Factors which are associated with ozone formation in urban areas have a lower significance for selecting the boundary for this nonattainment area since Southwest Wyoming is mostly rural with a low population density.

ANALYSIS

Sublette County and the surrounding counties (Table S.3-1) are rural with a low overall population density. There are no metropolitan areas with a population of 50,000 or more in this six-county area.

Table S.3-1: Population Density

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated 2007 Population	7,925	39,305	16,171	20,195	37,479	20,002
Area (square mile)	4,882	10,426	4,069	2,082	9,183	4,008
Population/square mile	2	4	4	10	4	5
Percent in Urbanized Area*	0	89	20	59	48	56
Percent in Rural Area*	100	11	80	41	52	44

* Based on 2000 Census

The largest community in Sublette County is Pinedale. The estimated population in 2007 was 2,043. The largest communities in the counties surrounding Sublette are Rock Springs (population 19,659), Green River (population 12,072) and Evanston (population 11,483). Rock Springs, Evanston, Riverton and Jackson are classified by the U.S. Census Bureau as Micropolitan Statistical Areas. Table S.3-2 shows population estimates and projections from the Wyoming State Department of Administration and Information.

Table S.3-2: Population Estimates and Projections

County and Cities	2007 Estimate	2008 Forecast	2010 Forecast	2015 Forecast	2020 Forecast	2025 Forecast	2030 Forecast
Sublette	**7,925**	**8,340**	**9,170**	**11,200**	**13,370**	**15,010**	**16,930**
Big Piney	476	501	551	673	803	902	1,017
Marbleton	919	967	1,063	1,299	1,550	1,741	1,963
Pinedale	2,043	2,150	2,364	2,887	3,447	3,869	4,364
Fremont	**37,479**	**37,870**	**38,390**	**39,320**	**40,110**	**41,130**	**42,370**
Dubois	1,033	1,044	1,058	1,084	1,106	1,134	1,168
Lander	7,131	7,205	7,304	7,481	7,632	7,826	8,062
Riverton	9,833	9,936	10,072	10,316	10,523	10,791	11,116
Lincoln	**16,171**	**16,560**	**17,240**	**18,710**	**20,100**	**21,190**	**22,430**
Afton	1,782	1,825	1,900	2,062	2,215	2,335	2,472
Alpine	764	782	815	884	950	1,001	1,060
Kemmerer	2,427	2,485	2,587	2,808	3,017	3,180	3,366
Star Valley Ranch	1,567	1,605	1,671	1,813	1,948	2,053	2,174
Sweetwater	**39,305**	**40,180**	**41,700**	**44,430**	**46,530**	**47,220**	**48,130**
Green River	12,072	12,341	12,808	13,646	14,291	14,503	14,782
Rock Springs	19,659	20,097	20,857	22,222	23,273	23,618	24,073
Teton	**20,002**	**20,240**	**20,570**	**21,340**	**22,140**	**23,470**	**24,990**
Jackson	9,631	9,746	9,904	10,275	10,660	11,301	12,033
Uinta	**20,195**	**20,420**	**20,730**	**21,210**	**21,550**	**21,950**	**22,440**
Evanston	11,483	11,611	11,787	12,060	12,253	12,481	12,760
Lyman	1,990	2,012	2,043	2,090	2,124	2,163	2,211
Mountain View	1,176	1,189	1,207	1,235	1,255	1,278	1,307

Population in Sublette County and Sublette County communities is expected to increase at a rate of approximately 5% over the next 23 years. Population in surrounding counties is expected to increase more slowly at rates of 2% or less.

The population in Sublette County has increased at a greater pace than surrounding counties (Table S.3-3). In the period 2006 to 2007, Sublette County continued to see faster growth than surrounding counties.

Table S.3-3: Population Growth

Population	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated 2007	7,925	39,305	16,171	20,195	37,479	20,002
Estimated 2006	7,359	38,763	16,383	20,213	37,163	19,288
Estimated 2004	6,879	38,380	15,780	20,056	36,710	18,942
2000	5,920	37,613	14,573	19,742	35,804	18,251
Percent Population Increase						
2000 to 2007	34%	4%	11%	2%	5%	10%
2004 to 2007	15%	2%	2%	1%	2%	6%
2006 to 2007	8%	1%	-1%	0%	1%	4%

Sublette County does not have any urbanized areas. Urbanized areas in surrounding counties are geographically distant from the monitor with the ozone exceedance in Sublette County (the Boulder monitor). As is described in Section 7 of this document, meteorological conditions associated with elevated ozone episodes greatly limit the possibility of emissions transport. Table S.3-4 shows the approximate distance to the Boulder monitor from communities with a population greater than 9,000 in 2007. Additionally, Riverton is separated from the UGRB by the Wind River Range. (Appendix S3 - **Figure -** Wyoming Population Density by Census Tract)

Table S.3-4: Distance to Boulder Monitor

(Miles, approximate)

Riverton	Green River	Rock Springs	Jackson	Evanston
73	82	80	75	118

The analysis in Section 7 of this document will demonstrate that emissions from sources outside of the UGRB do not significantly influence ozone levels at the Boulder monitor during elevated ozone episodes.

References:

1. http://www.census.gov/main/www/cen2000.html, U.S. Census Data.
2. http://eadiv.state.wy.us/pop/CO-07EST.htm, State of Wyoming populations statistics and projections by county and city.
3. Appendix S.3., Population Density by Census Tract

SECTION 4
TRAFFIC AND COMMUTING PATTERNS

SYNOPSIS

The number of commuters into or out of Sublette County (and the UGRB) is small and does not support adding other counties or parts of counties into the nonattainment area based on contribution of emissions from commuters from other counties.

The percent of emissions from on-road mobile sources is small within the proposed nonattainment area: 7% of NOx and 0.3% of VOCs. Even if this source increases, it will remain a small percentage of total emissions.

Interstate 80, the interstate highway that is nearest to the Boulder monitor, is approximately 80 miles south of the Boulder monitor. Ozone monitors in closer vicinity to the interstate have not shown ozone exceedances. I-80 traffic is not considered to be a significant contributor of emissions that impact the Boulder monitor during ozone events.

ANALYSIS

Consistent with the rural character of the counties in southwest Wyoming including Sublette County, traffic volumes are low. The Wyoming Department of Transportation's (WYDOT)[1] inventory shows traffic volume at 447,953 daily vehicle miles traveled (DVMT) for Sublette County in 2007. WYDOT inventories are based on travel on paved roads. Table S.4-1 shows traffic volumes for Sublette County and surrounding counties for 1994, 2004 and 2007.

Emissions from mobile sources within the UGRB are very low, as would be expected from such low DVMTs. As shown in Table S.2-1, NOx emissions for the first quarter of 2007 are approximately 136 tons (7% of total NOx) and VOC emissions are 79 tons (0.3%). This makes emissions from this sector of much lower significance than is typically seen in urban nonattainment areas.

Approximately 90% of the traffic volume in Sweetwater and Uinta Counties is interstate traffic. Interstate 80 is located approximately 80 miles south of the Boulder monitor, the ozone monitor that showed the exceedance. There are five ozone monitors located closer to the Interstate: Wamsutter (~1 mile), OCI (~12 miles), South Pass (~45 miles), Murphy Ridge (~5 miles), and Jonah (~60 miles) (See Figure S.1-1). None of the monitors located closer to the Interstate have shown an ozone exceedance.

Table S.4-1: WYDOT - 2007 Traffic Surveys

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
DVMT-2007	447,953	2,667,117	615,113	1,013,595	979,546	622,356
DVMT - interstate-2007		2,421,684		911,916		
DVMT-2004	342,034	2,473,882	564,771	944,416	892,814	600,836
DVMT-1994	229,553	1,917,738	466,753	761,626	737,863	504,904
Increase 1994 to 2007	95%	39%	32%	33%	33%	23%
Miles of roads	229.2	568.7	337.2	218.4	507.2	144.2
DVMT/mile of road	1954	4689	1824	4641	1931	4315

The Wyoming Department of Employment (DOE)[2] surveys commuting trends between counties. Table S.4-2 summarizes the average number of commuters for the years 2000 through 2005 that commute between Sublette County (the county with the Boulder monitor) and surrounding counties. Although commuting has increased for some neighboring counties, such as Sweetwater County, the volume of commuters is low.

Table S.4-2: Wyoming DOE Commuter Surveys 2000 Through 2005

Commuters driving to Sublette from:	2000	2001	2002	2003	2004	2005
Fremont	20	29	17	26	41	47
Lincoln	112	117	106	84	100	128
Sweetwater	62	86	79	77	111	185
Teton	49	52	45	35	38	49
Uinta	14	12	22	31	38	53
Total						462
Commuters driving from Sublette to:						
Fremont	81	67	70	37	48	44
Lincoln	77	59	76	114	97	93
Sweetwater	126	129	109	121	152	209
Teton	171	148	150	135	142	130
Uinta	33	66	55	31	20	26
Total						502

North Carolina's Economic Development Intelligence System (EDIS)[3] compiled 2000 Census data to determine the number of commuters in Wyoming counties. Extrapolating this data to 2008, to account for only population growth, the estimated number of commuters in Sublette County and surrounding counties is shown in Table S.4-3. Since rapid population growth in Sublette County is biased toward the working age population, the straight extrapolation from 2000 data is likely to underestimate the number of commuters. The EDIS data indicate the majority of commuters commute within their county of residence. The number of commuters leaving Sublette County calculated by the Wyoming DOE correlates well with the EDIS generated estimates of commuters leaving Sublette County.

Table S.4-3: Number of Commuters in Sublette and Surrounding Counties

	Sublette	Sweetwater	Lincoln	Uinta	Fremont	Teton
Estimated number of commuters in 2000*	2767	18,012	6069	8921	15,074	10,527
Estimated number of commuters in 2008	3357	18,726	7084	9114	15,761	11,811
Estimated number of 2008 commuters that stay in their county	2921	17,977	5596	7565	14,973	11,338

* 2000 Census data

Commuting patterns in Sublette County and in surrounding counties show that commuting to or from the adjacent counties is not a major source of VMT in Sublette County. Therefore, commuters from adjacent counties are not a significant factor in ozone generation in the proposed nonattainment area.

Reference:

1. Appendix S.4.A, 2007 Vehicle Miles on State Highways By County
2. Appendix S.4.B, Commuting Patterns in Sublette County
3. North Carolina Department of Commerce web site. https://edis.commerce.state.nc.us/docs/countyProfile/WY/

SECTION 5
GROWTH RATES AND PATTERNS

SYNOPSIS

The pace of growth in the oil and gas industry in Sublette County is significantly greater than in surrounding counties. While population is growing in Sublette County, the county and surrounding area is rural with a low population density. Population growth does not influence determination of a designation area boundary in this case.

ANALYSIS

Statistical data available is broken down on a county basis. The following analysis compares Sublette County to surrounding counties. While the recommended nonattainment area includes a portion of Sweetwater and Lincoln counties in addition to Sublette, the trends described for Sublette County also hold true, in general, to the recommended nonattainment area.

Population growth is described in Section 3. Sublette County population has grown at an annual rate of approximately five percent over the last seven to ten years. Sublette County is forecast to continue to grow at this rate for the foreseeable future. Counties surrounding Sublette have grown at rates of less than two percent during this time period and are forecast to continue to grow at this slower pace.

Industrial growth in Sublette County is driven by the oil and gas (O&G) industry. Table S.5-1 shows the increase in O&G production for Sublette County as shown by the number of well completions for years 2000 through 2008. Table S.5-2 shows total well completions for 2005 through 2008 for Sublette, Sweetwater, Uinta and Lincoln counties. Sweetwater and Lincoln counties also show an increasing trend in well completions, though to a lesser extent than in Sublette. Teton County is not listed because it has no oil and gas production. Fremont County is not shown because O&G production areas in Fremont County are separated from the other counties by the Wind River Mountain Range.

Table S.5-1: Completion Report Sublette County*

(Confidential Records Are Not Listed)

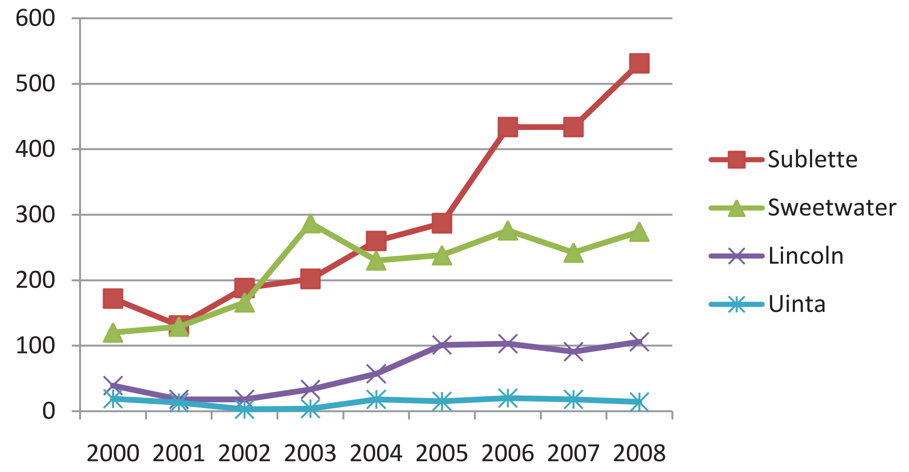
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Distinct Gas Well Completion Count	126	110	150	185	252	281	428	420	517
Distinct Oil Well Completion Count	45	20	32	15	5	0	3	5	4
Total Distinct Well Completion Count	172	131	188	202	260	287	434	434	531

*Wyoming Oil and Gas Conservation Commission (WOGCC)

Table S.5-2: Total Well Completions/Oil, Gas, and CBM* (Confidential Records Are Not Listed)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
Sublette	172	131	188	202	260	287	434	434	531
Sweetwater	120	129	166	287	230	238	276	242	274
Lincoln	39	18	18	33	57	101	103	91	106
Uinta	19	13	3	4	18	15	20	18	14

*Wyoming Oil and Gas Conservation Commission (WOGCC)

Figure S.5-1: Well Completions Per County



As Figure S.5-1 shows, there have been more O&G well completions in Sublette than for the surrounding counties. Table S.5-3 and Figure S.5-2 show the steady growth in Sublette County O&G production since 2000.

Table: S.5-3 Sublette County Production Levels			
	Oil Bbls	**Gas Mcf**	**Water Bbls**
2008	7,666,396	1,143,614,170	22,921,983
2007	7,096,499	1,008,001,400	18,251,807
2006	5,769,581	880,855,575	13,203,000
2005	5,102,164	814,748,425	11,641,926
2004	4,705,836	731,276,509	11,812,077
2003	4,539,385	655,573,062	10,526,328
2002	4,380,011	571,000,866	13,950,895
2001	3,840,436	493,577,283	7,785,291
2000	3,345,063	448,281,668	7,364,792

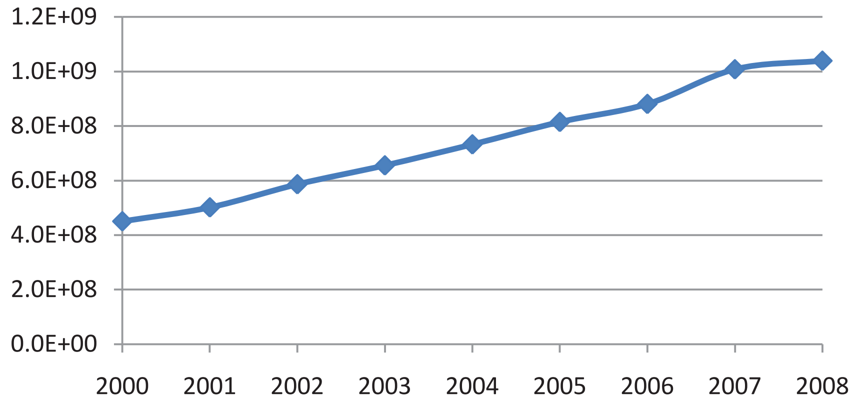


Figure S.5-2: Sublette County Gas Production Mcf

Table S.5-4 shows growth in the oil and gas industry by county through the following three measures: oil production (in barrels), gas production (in thousand cubic feet), and produced water generation (in barrels). Growth in production of gas and water is increasing in Sublette County and is either static or decreasing in the surrounding counties.

Table S.5-4: Four County Production				
	Oil Bbls			
	Sublette	Lincoln	Sweetwater	Uinta
2008	7,666,396	819,751	5,392,316	1,341,993
2007	7,096,499	801,807	5,738,262	1,506,562
2006	5,769,581	782,165	5,295,610	1,914,262
2005	5,102,164	762,801	4,872,531	2,246,896
	Gas Mcf			
2008	1,143,614,170	89,516,900	240,214,449	130,282,928
2007	1,008,001,400	89,189,164	235,687,851	128,068,870
2006	880,855,575	85,753,007	238,339,251	139,700,716
2005	814,748,425	83,579,467	222,772,057	141,490,407
	Water Bbls			
2008	22,921,983	1,228,058	42,026,953	3,011,981
2007	18,251,807	1,300,854	47,522,714	2,843,082
2006	13,203,000	1,375,969	49,928,115	2,641,554
2005	11,641,926	1,065,943	45,110,120	2,950,473

References:

Wyoming Oil and Gas Conservation Commission (http://wogccms.state.wy.us/)

SECTION 6
GEOGRAPHY/TOPOGRAPHY

SYNOPSIS

The Wind River Range, with peaks up to 13,800 feet, bounds the UGRB to the east and north; the Wyoming Range, with peaks up to 11,300 feet, bounds the UGRB to the west.

Significant terrain influences the weather patterns throughout Southwest Wyoming. Other terrain features such as river and stream valleys also influence local wind patterns.

Mountain-valley weather patterns in the UGRB tend to produce limited atmospheric mixing during periods when a high pressure system is in place, setting up conditions for temperature inversions, which are enhanced by the effect of snow cover.

ANALYSIS

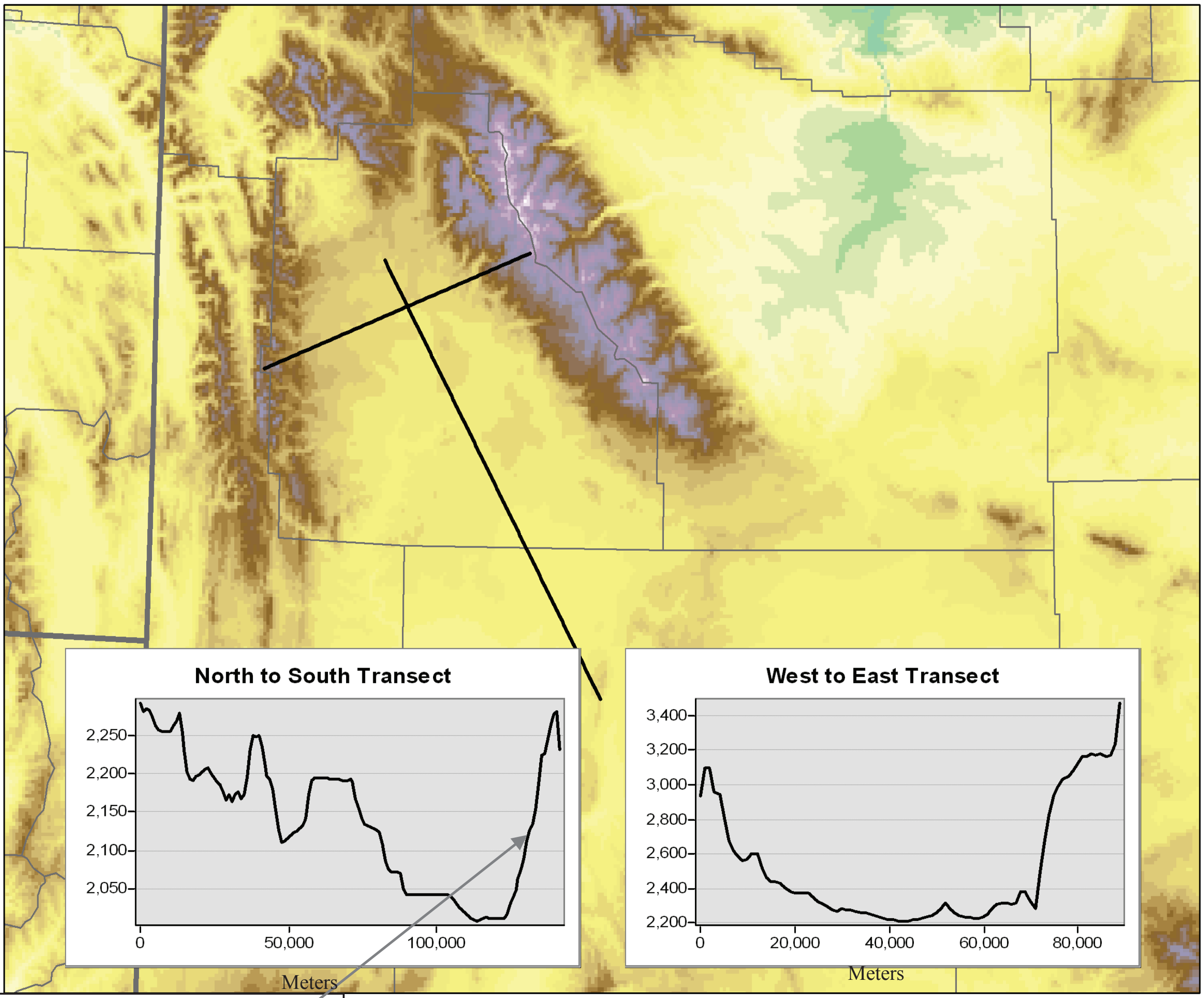
Southwest Wyoming and the UGRB are within the Wyoming Basin Physiographic Province. Topography in the UGRB is characterized by low, gently rolling hills interspersed with buttes. Elevations range from approximately 7,000 to 7,400 feet above mean sea level (AMSL) in the lowest portions of the UGRB. The Wind River Range, with peaks up to 13,800 feet, bounds the UGRB to the east and north and the Wyoming Range, with peaks up to 11,300 feet, bounds the UGRB to the west. There are also important low terrain features such as the Green River Basin and the Great Divide Basin.

Mountain elevations decrease moving south along both the Wyoming and Wind River ranges. Along the western boundary of the Green River Basin, in the southern part of the Wyoming Range, the elevation decreases to about 6,900 feet above mean sea level (AMSL) with some peaks in the 7,500 to 8,000-foot range. Moving south along the Wind River Range, the elevation decreases to 7,800 feet at South Pass.

Figure S.6-1: Nonattainment area shown (blue outline) against an aerial view of the topography in the Upper Green River Basin and adjacent areas.

The surrounding significant terrain features effectively create a bowl-like basin in the northern portion of the Green River Basin, which greatly influences localized meteorological and climatological patterns relative to geographical areas located outside of the UGRB. Although difficult to quantify over the entire UGRB valley, the UGRB is roughly 900 to 1,300 meters (3,000 to 4,300 feet) lower than the terrain features bounding the UGRB to the east and west. Typical elevation profiles within the UGRB are illustrated in two different cut-planes (transects) across the UGRB, as shown in Figure S.6-2.

The southern boundary of the area is defined by river and stream channels. To the east the Big Sandy, Little Sandy and Pacific Creek drainages define the boundary and to the west the Green River and Fontenelle Creek drainages define the boundary.



Approximate South boundary of proposed nonattainment area

Figure S.6-2: Transects across the Upper Green River Basin (running north-south and west-east) showing cross sections of the terrain; terrain elevations and distance units shown in the transects are in meters.

Significant terrain in the UGRB has an impact on the local meteorology (wind speed, wind direction, and atmospheric stability). In mountain-valley areas – such as the UGRB – during the night cold air will accelerate down the valley sides (downslope winds), while during the day warmer air will flow up the valley sides (upslope winds). At night, this can create a cold pool of air within the UGRB that stratifies the atmosphere (inhibits mixing) since colder, denser air exists at the surface with warmer air above. Further, at the valley floor, the wind speed is likely to be lower than in an open plain as the roughness of the surrounding terrain tends to decrease wind speeds at the surface. The terrain obstacles surrounding the UGRB also tend to cut-off, block, or redirect air that might normally flow through the valley. This effect is exacerbated during times of calm weather, such as the passage of a high pressure system that tends to set up conditions for strong surface-based temperature inversions.

The Wind River Range on the east and the Wyoming Range on the west provide significant barriers to movement of ozone and ozone precursors into the area proposed for a nonattainment area designation. Although the recommended southern boundary is not bordered by a mountain range, the southern boundary lies along two significant drainage divides: the Fontenelle/Green River and the Pacific/Big Sandy River. These geographic features influence air flow, although they do not provide an absolute barrier to migration. The influence of these geographic features on wind flows, especially during periods of low winds which are needed for ozone formation is illustrated in Figure S.7-17. This figure shows winds generally conforming to the drainages which establish the southern boundary of the proposed nonattainment area. The conclusions about the southern boundary are further supported by the meteorological analyses presented in Section 7.

SECTION 7
METEOROLOGY

SYNOPSIS

The unique meteorology in the UGRB of Wyoming creates conditions favorable to wintertime ozone formation.

The meteorology within the UGRB during winter ozone episodes is much different than on non-high ozone days in the winter, and is also much different than the regional meteorology that exists outside of the UGRB during these wintertime high ozone episodes.

The 2008 field study data reveal that, for the days leading up to the February 19-23, 2008 ozone episode, sustained low wind speeds measured throughout the monitoring network were dominated by local terrain and strong surface-based inversions, which significantly limited the opportunity for long-range transport of precursor emissions and ozone to reach the Boulder monitor.

Minimal emissions transport and dispersion, due to the influence of localized winds (light winds) in the UGRB characterize the February 19-23, 2008 ozone episode.

An ozone-event specific wind field was developed to more accurately simulate meteorological conditions in the UGRB and surrounding areas, and was used to drive a trajectory model for air parcel movement into and out of the UGRB.

Trajectory analyses were used to develop a reasonable southern boundary for the nonattainment area.

The unique meteorological conditions in the UGRB are one of the most significant factors for assigning this nonattainment boundary.

ANALYSIS

General

There is significant topographic relief in Wyoming which affects climate and daily temperature variations. This is a semiarid, dry, cold, mid-continental climate regime. The area is typified by dry windy conditions, with limited rainfall and long, cold winters. July and August are generally the hottest months of the year, while December and January are the coldest. Pinedale’s mean temperature in January is 12.5°F with a mean of 60°F in July (Western Regional Climate Center, 2009). The high elevation and dry air contribute to a wide variation between daily minimum and maximum temperatures. At Pinedale, the total annual average precipitation is about 10.9 inches, and an average of 61 inches of snow falls during the year.

Strong winds are common in Wyoming, especially in the south. Wind velocity can be attributable, in part, to the prevailing westerly winds being funneled through the Rock Mountains at a low point in the Continental Divide.

The meteorological conditions conducive to the formation of high ozone levels in the UGRB during the winter and early spring are characterized by:

- A stable atmosphere, characterized by light low-level winds

- Clear or mostly sunny skies
- Low mixing heights or capping inversions
- Extensive snow cover
- Low temperatures

The above conditions take some time to develop (at least 48 hours after a storm frontal passage), and occur during periods when the synoptic weather is dominated by high pressure over the western Rockies.

Looking at the meteorological conditions in the UGRB, elevated ozone episodes in 2005, 2006 and 2008 were associated with strong temperature inversions and light low-level winds. This was the case during the February 19-23, 2008 ozone episode, in which the highest ozone concentrations monitored to date in the UGRB were recorded at the Boulder monitor. Because these meteorological conditions are common to all of the high ozone episodes in the UGRB observed to date, the ozone episode of February 19-23, 2008, a 5-day period marking the longest consecutive ozone episode observed, is considered to be representative of other ozone episodes. This particular 5-day ozone episode is the primary focus of this section on meteorological influences and wintertime high ozone.

Winter Ozone Field Studies

After elevated ozone levels were monitored in the winter of 2005 and 2006; the AQD initiated intensive field studies to collect meteorological and ambient data in the first quarter of 2007, 2008, and 2009 throughout the Green River Basin to better understand the relationships between winter meteorological conditions and high ozone levels versus low ozone levels. In spite of careful planning to record data, the winter of 2007 did not produce conditions conducive to the formation of ozone. In contrast, the winter of 2008 provided a significant amount of data on ozone formation since there were several high ozone episodes. A map showing the monitoring sites employed in the 2008 field study and regional terrain features in the 2008 study area is shown in Figure S.7-1. The entire data set and reports on the winter studies completed to date are available on the WDEQ/AQD website (http://deq.state.wy.us/aqd/Monitoring%20Data.asp). AQD has continued field studies into 2009, but those results will not be available until later in 2009.

During January and the beginning of February 2008, the study area was under the influence of a series of weak to moderately strong synoptic disturbances that migrated from the Gulf of Alaska, across the Pacific Northwest and southern British Columbia and the northern Great Basin and into the Northern Rockies. These weather features generally moved rapidly through southwest Wyoming as they migrated along a belt of strong westerly to northwesterly winds aloft that were associated with a persistent high pressure ridge located over the eastern Pacific, off California. In addition, a number of deep Pacific troughs moved across the area earlier in the winter and into the first half of January. The end result of all this activity was the deposit of substantial snow cover in southwestern Wyoming, including the UGRB, which was to remain in place through the rest of the winter. After mid-February, the eastern Pacific ridge exhibited a tendency to extend or migrate into the interior west until it finally moved directly over southwest Wyoming by February 20, 2008.

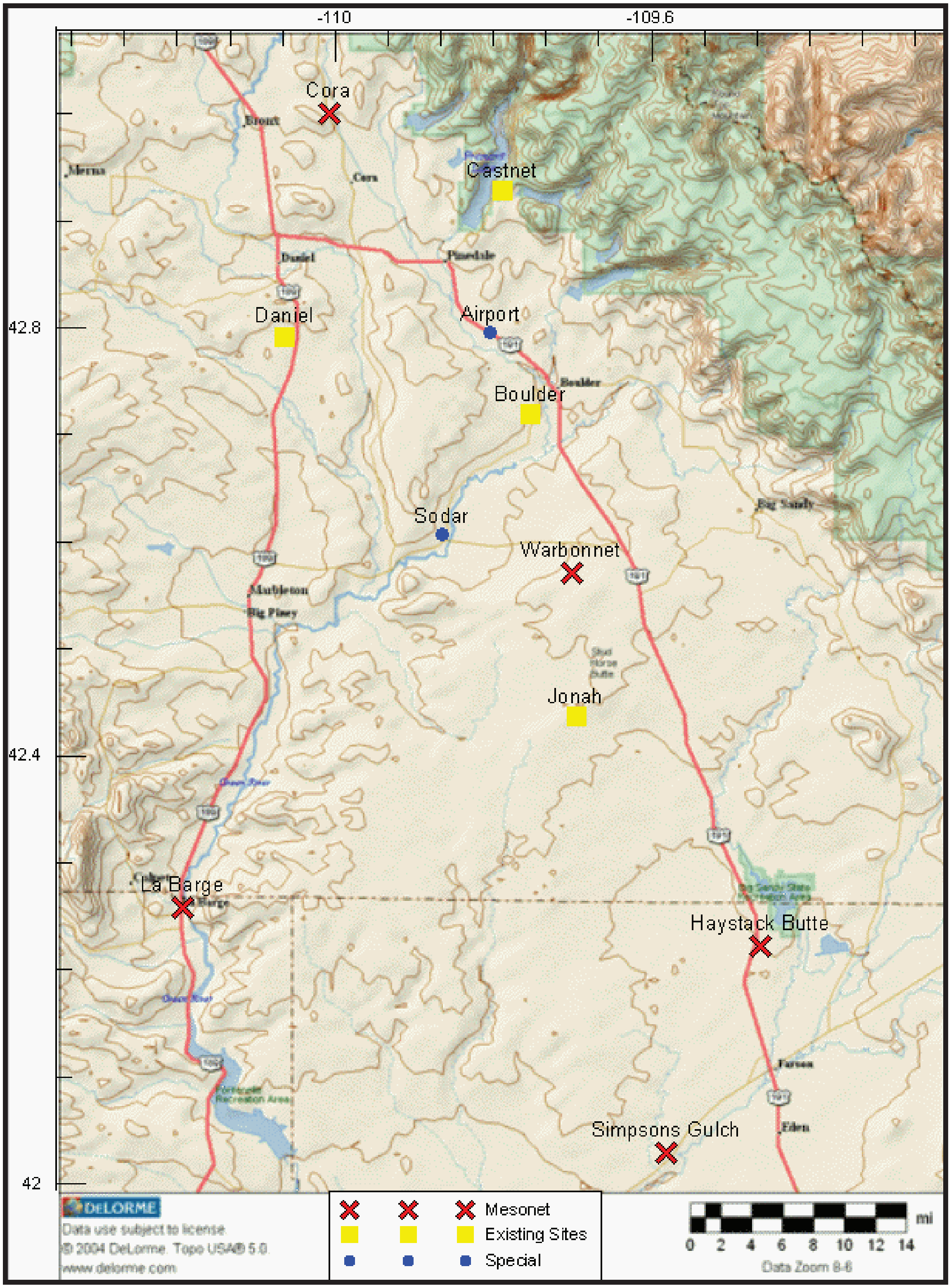


Figure S.7-1. Surface and upper air monitoring sites employed in the 2008 field study.

Comparison of 2007 and 2008 Field Study Observations

Snow Cover and Sunlight

Comparison of meteorological conditions in 2008 with those prevailing during the 2007 field study revealed that one of the key differences was the extensive snow cover in 2008 which was not present during 2007. Snow cover appears to be a key ingredient in winter ozone development, specifically, fresh snow, which results in higher surface albedo, perhaps as great as 0.9. The increased surface albedo results in greater actinic flux and therefore elevated NO_2 photolysis rates. The elevated photolysis rate due to the high (snow cover driven) albedo is likely greater than the photolysis rate in the UGRB in the summer months.

During the 2007 field study, although there were extended periods when synoptic-scale meteorological conditions were conducive to poor horizontal dispersion, the lack of snow cover and subsequent lower UV albedo reduced the amount of UV radiation available for photolysis and associated ozone production. In addition, the 2007 and 2008 field studies suggest that the sensible and radiative heat flux impacts of the snow cover enhance low-level atmospheric stability, substantially reducing vertical mixing during most or all of the daylight hours.

Low Wind Speeds

Stable, stagnant weather conditions occurred in southwest Wyoming during the period from February 18 through 22, 2008. The main synoptic feature responsible for this was a strong Pacific high pressure ridge that slowly migrated across the western United States. This period was dominated by low wind speeds in the boundary layer, which reduced pollutant transport and dispersion. This effect is shown in Figure S.7-2 where ozone concentrations and wind speeds are plotted for the Boulder monitor for February and March of 2008.

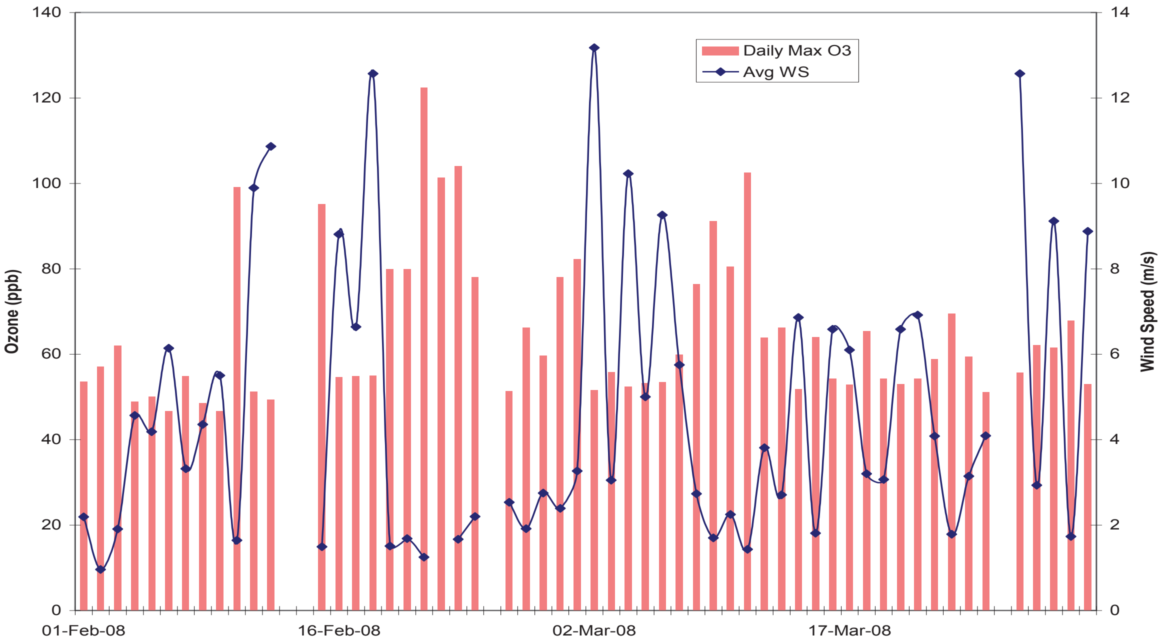


Figure S.7-2. Wind speed and ozone concentrations plotted for the Boulder monitor in February and March 2008.

The 2008 field study data reveal that the sustained low wind speeds measured throughout the monitoring network were dominated by local terrain and strong surface-based inversions, which significantly limited the opportunity for long-range transport of precursor emissions and ozone on the days leading up to the February 19-23, 2008 ozone episode.

Ozone Carryover

When the favorable synoptic conditions described above develop late in the day or during the night hours, the first high ozone concentrations typically develop the following day between approximately 11:00 and 13:00 so long as favorable conditions for high ozone formation persist. During a day of elevated ozone, such as February 20, 2008, the high readings at the monitors in the UGRB peak in the afternoon. As the day progresses, lower but still elevated concentrations continue, in some cases lasting well into the evening hours and, in a few cases, past midnight before lowering. When the following day continues to have these favorable weather conditions, the ozone levels begin to rise earlier than the previous day and frequently to much higher levels, indicative of some carryover of ozone and precursors from one day to the next. Once high ozone concentrations have formed, ozone levels were observed to remain elevated even with increasing cloud cover ahead of an approaching storm system. Additionally, wind reversals, which were most apparent at the Jonah and Boulder monitors, were observed at many of the monitoring sites during the field study; which further assisted in the carryover and build-up of ozone and ozone precursors from emission sources in close proximity to the monitors. Ozone concentrations do not return to near background conditions until brisk (usually west or northwesterly) winds have arrived and scoured out the surface inversion.

Atmospheric Mixing

The observed weather patterns in the 2007 field study showed that the winter storm systems generally did not provide a strong push of cold air and did not produce much precipitation in the project area, but did allow strong wind speeds aloft with considerable mixing of the atmosphere. Specifically, the weather conditions over the study area during February and March of 2007 were characterized by less precipitation (including less snow depth), stronger winds aloft and much warmer surface temperatures compared to the previous two winters. High pressure systems in 2007 tended to keep the air mass over the study area relatively well mixed and mild, which in turn did not allow for snow accumulation and strong inversion development.

Feb. 19 – 23, 2008 Case Study Illustrating the Specific Weather Conditions Which Produce Elevated Ozone in the Upper Green River Basin

This ozone episode is of particular interest for study, as it: 1) occurred over five days, marking the highest 1-hour and 8-hour ozone concentrations recorded at the Boulder monitor to date, 2) occurred during a field study Intensive Operating Period (IOP) that was in place to measure detailed actual ambient and meteorological conditions leading up to and during this multi-day winter ozone episode, 3) provides a high quality database of observations for several meteorological parameters, both during IOPs and regular hourly observations during this ozone episode, and 4) provides information which clearly shows how the topography in the Upper Green River Basin creates different meteorological conditions within the UGRB. A summary of the daily maximum 8-hour averaged ozone concentrations monitored at the Jonah, Boulder, and Daniel FRM monitors during this ozone episode, as well as the day immediately preceding it, are provided in Table S.7-1.

Date	Jonah (ppb)	Boulder (ppb)	Daniel (ppb)
2/18/09	45	55	54
2/19/08	80	79	74
2/20/08	75	79	76
2/21/08	84	122	62
2/22/08	102	101	76
2/23/08	76	104	74

Table S.7-1. Summary of daily maximum 8-hour averaged ozone concentrations monitored at the Jonah, Boulder, and Daniel monitors during February 18-23.

A synopsis of the particular meteorological conditions associated with the February 19-23, 2008 winter high ozone episode is provided below, describing the evolution of the meteorological conditions that were in place during the February 19-23, 2008 ozone episode.

Synopsis of 19 – 23 February 2008 Ozone Episode

Figure S.7-3 shows the 700 millibar (mb) chart for the morning of February 19, 2008, which shows the axis of the Pacific ridge extending north and south from the Four Corners area, through northwestern Idaho and up into eastern British Columbia. At that time, the ridge axis was still west of Wyoming, resulting in fairly strong northwesterly gradient flow (winds blowing from the northwest along the isobars) just above ground level in southwest Wyoming. With clear skies accompanying the approaching ridge, and a good snow cover at the surface, a capping inversion formed overnight and persisted throughout the next day in the UGRB. However, the strong winds above the stable layer, along with mixing heights on the order of several hundred meters, transferred sufficient momentum downward, allowing these northwest winds to mix down to the surface during the day resulting in predominant northwesterly wind patterns within the UGRB.

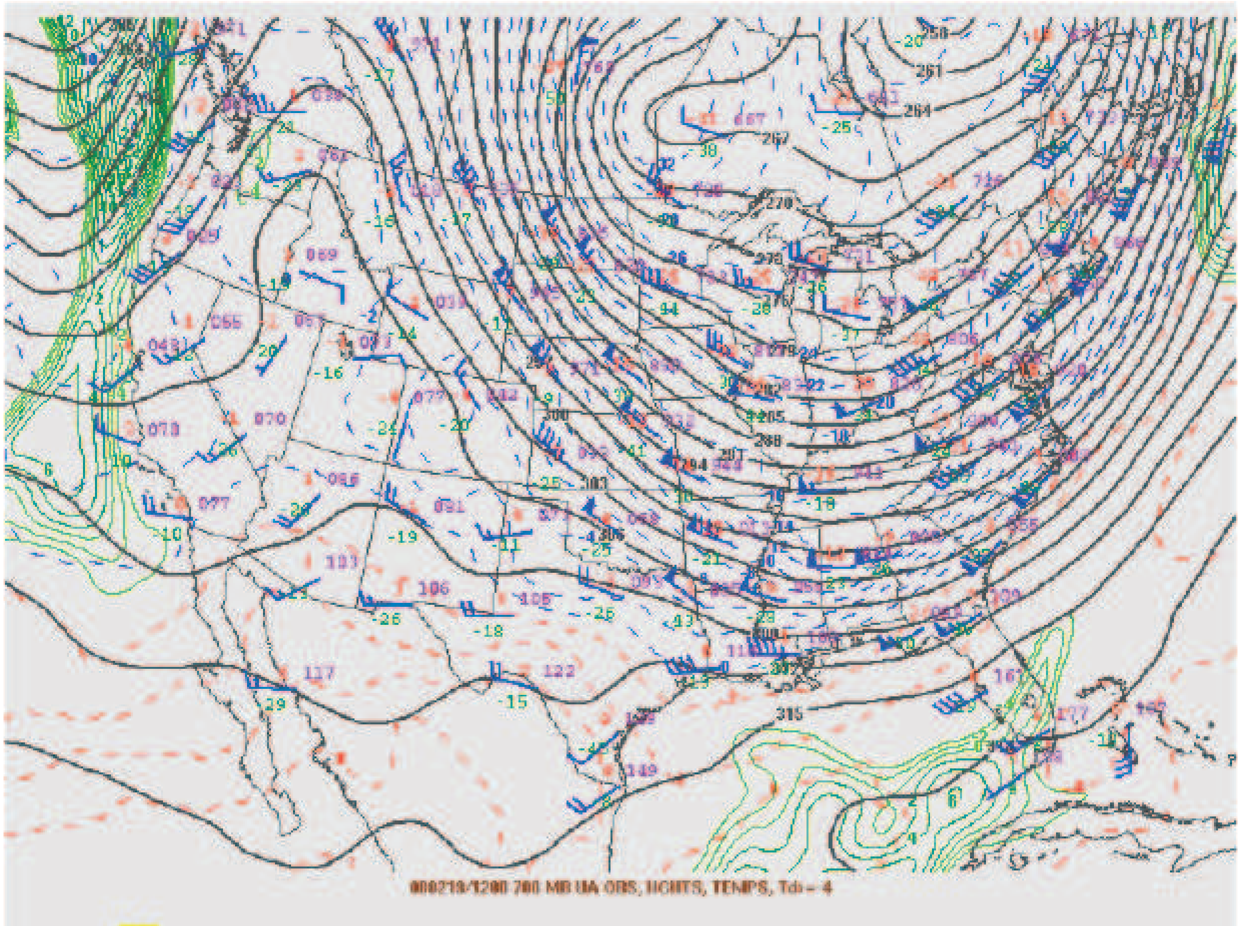


Figure S.7-3. Constant pressure map for 700 mb, 02/19/08 (1200 UTC) [(5 am LST)].

The high pressure ridge continued to progress slowly eastward during February 20th resulting in the central axis pushing into southwestern Wyoming by the middle of the day. As a result, a capping low-level inversion was observed throughout the day, and a weakened northwest gradient wind flow allowed the establishment of local valley flow patterns in the area. Local valley flow patterns are characterized by light variable winds with pronounced down slope winds at night. A weak storm system that moved out of California and across the southern Great Basin during February 20th forced some broken high cloudiness over southwestern Wyoming during the afternoon, but the clouds failed to curtail ozone production in the area, based on monitored data.

Figure S.7-4 shows the 700 mb chart for the evening of February 21, 2008. Although the high pressure ridge had weakened by the afternoon of February 21st, it had also flattened and the central ridge axis was over southwestern Wyoming through the entire day. The resulting light wind situation, characterized by low wind speeds and significantly reduced air flow movement within the UGRB, enabled the strongest ozone production seen to date in Sublette County.

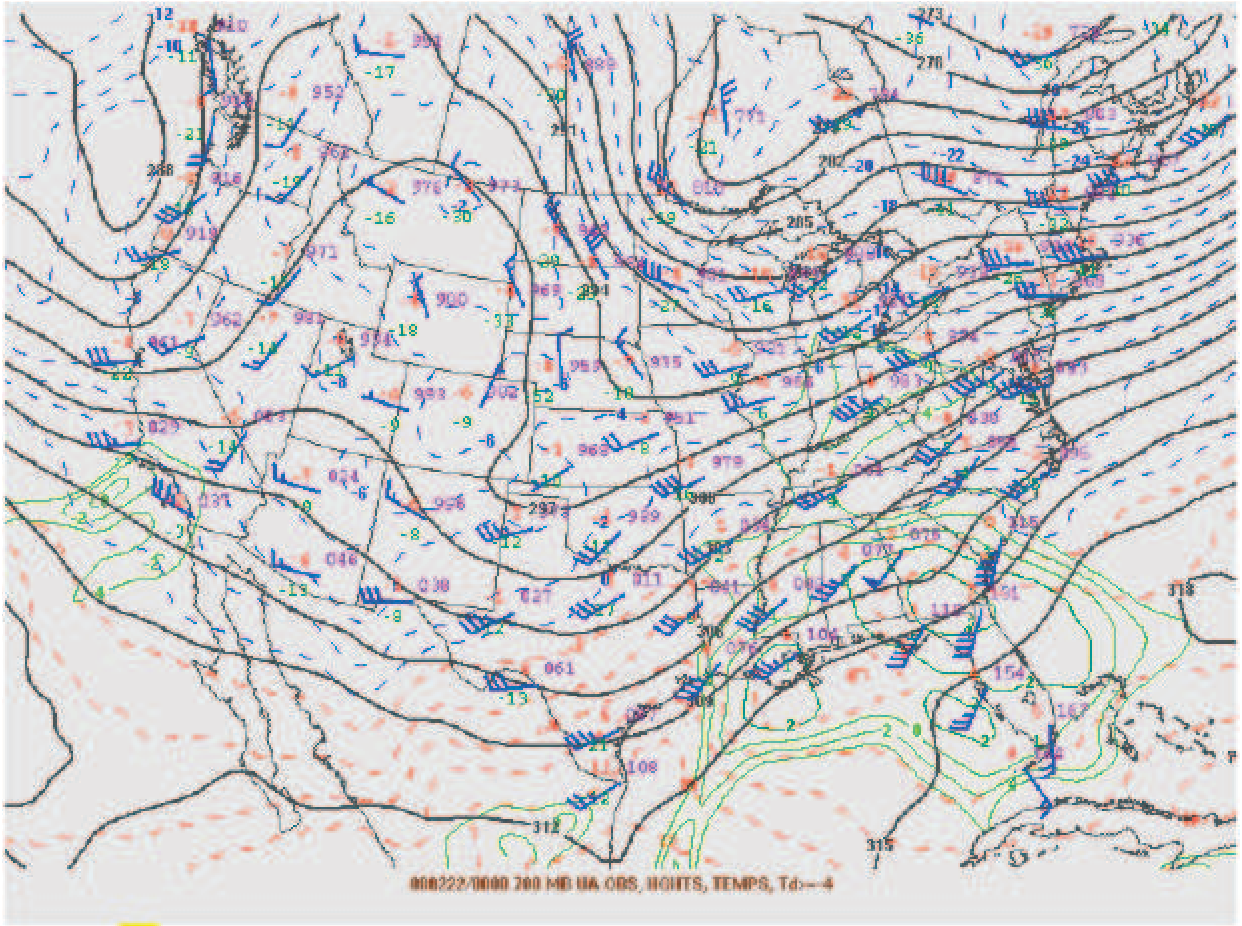


Figure S.7-4. Constant pressure map - 700 mb, 02/22/08 (0000 UTC) [02/21/08 (5 pmLST)].

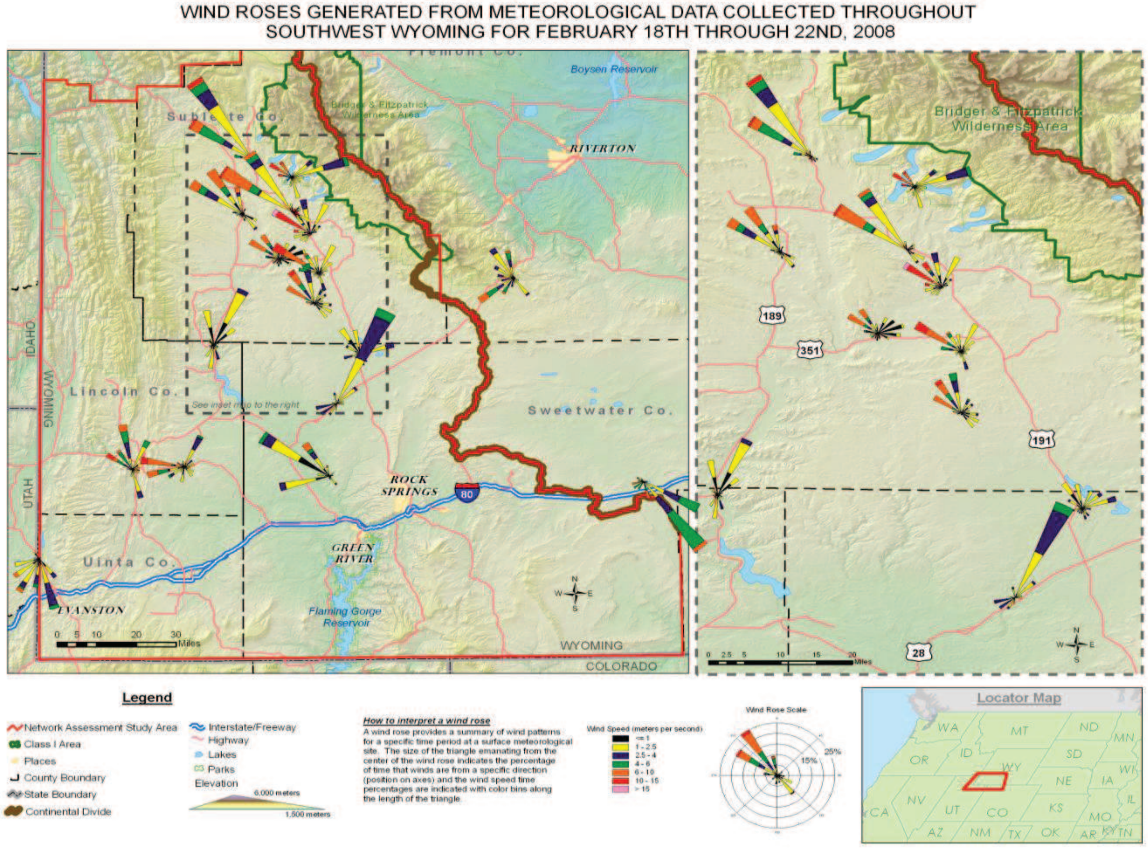
On February 21, 2008, the low level inversion stayed intact through the entire daylight period, keeping ground level emissions trapped near the surface. With the very light and variable winds above the inversion (see Figure S.7-10) localized wind flow patterns near the ground level developed during the day allowing emissions to transport along those pathways (see Figure S.7-6 and Figure S.7-7). The height of the 700 mb pressure surface during the day was around 3,020 meters (MSL), the temperature averaged about -6° C, and the wind speeds were less than 5 knots. The height of the 500 mb pressure surface averaged around 5,550 meters (MSL) and the wind speeds at that height were around 15 knots.

The high pressure ridge continued to weaken during February 22, 2008, while a shortwave low pressure trough approached southwestern Wyoming from the northwest. Skies became mostly cloudy during the morning hours and light precipitation spread over the area later in the afternoon; the low level inversion stayed intact well into the afternoon, and ozone concentrations remained high during most of the day. It was anticipated that the stable layer would be mixed-out by the trough by early morning the next day and trapped emissions would be dispersed. Instead, the late arrival of the trough allowed one more day of high ozone concentrations.

Description of Surface Wind Data

With the addition of the temporary mesonet monitoring sites to the existing permanent meteorological monitoring stations in the 2007 and 2008 field studies, a fairly detailed picture of wind flow patterns within the UGRB was obtained, revealing that the wind flow patterns were distinctly different throughout the northern and southern portions of southwest Wyoming. A composite map of wind rose plots generated from meteorological data collected throughout southwest Wyoming during the time period 18 – 22, February 2008 is provided in Figure S.7-5.

As can be seen in Figure S.7-5, the wind patterns in the northern portion of Sublette County reflect the prevailing northwest winds typical of this area during most of the year. However, this moderately strong, organized northwest flow does not extend to the southern monitoring sites (Haystack Butte and Simpsons Gulch). Monitoring sites located in Sweetwater, Lincoln and Uinta Counties experienced a generally westerly wind flow, which was also a characteristic of the prevailing flows noted during the 2007 field study at those monitoring sites. Additionally, during the afternoon, winds reversed at some monitoring sites in the UGRB, shifting from the northwest to the southeast; this mid-day flow reversal is typical of high ozone days in the UGRB, and is thought to be causing recirculation of pollutants within the UGRB.



How to interpret a wind rose

A wind rose provides a summary of wind patterns for a specific time period at a surface meteorological site. The size of the triangle emanating from the center of the wind rose indicates the percentage of time that winds are from a specific direction (position on axes) and the wind speed time percentages are indicated with color bins along the length of the triangle.

Figure S.7-5. Composite wind rose map for February 18 – 22, 2008 at monitoring sites located throughout Southwest Wyoming.

Wind vector fields were also examined spatially to gain an understanding of flow patterns in the field study area. Winds on a typical ozone episode day (February 20th), and on the day with the highest 8-hour ozone concentration recorded at the Boulder monitoring site (February 21st) are shown in Figure S.7-6 and Figure S.7-7.

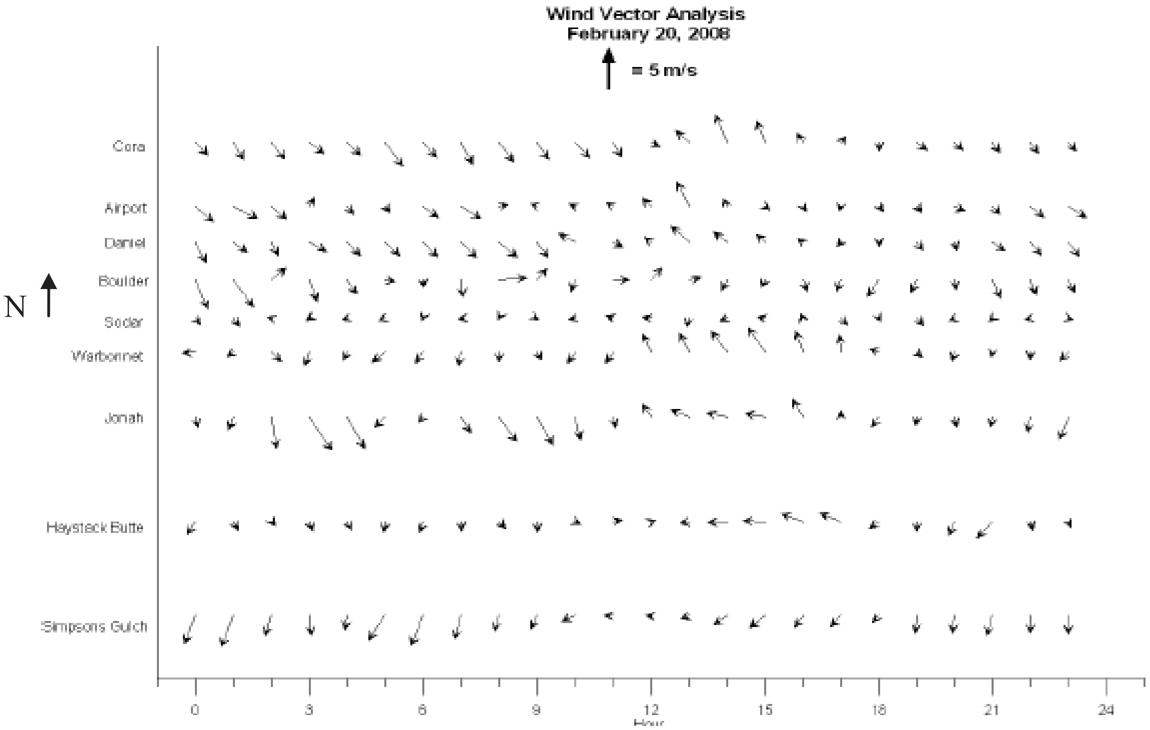


Figure S.7-6. Time-series showing February 20, 2008 hourly wind vectors for monitors used in 2008 field study monitoring network.

As shown in Figure S.7-6, winds in the UGRB are generally out of the northwest in the morning until about mid-day, at which point the flow has reversed with southeasterly winds, or at least southerly component winds are observed at most sites. This continues through the afternoon until 18:00 MST at which time the flow begins to switch back to the northwest, and by 6:00 MST the following morning, winds are northwest or northeast at nearly all of the monitoring sites. The switch from an overnight flow consisting of generally northwesterly or down slope winds, which last until approximately mid-day before reversing to a generally southeasterly wind flow pattern during the afternoon, was repeated on many of the 2008 ozone episode days.

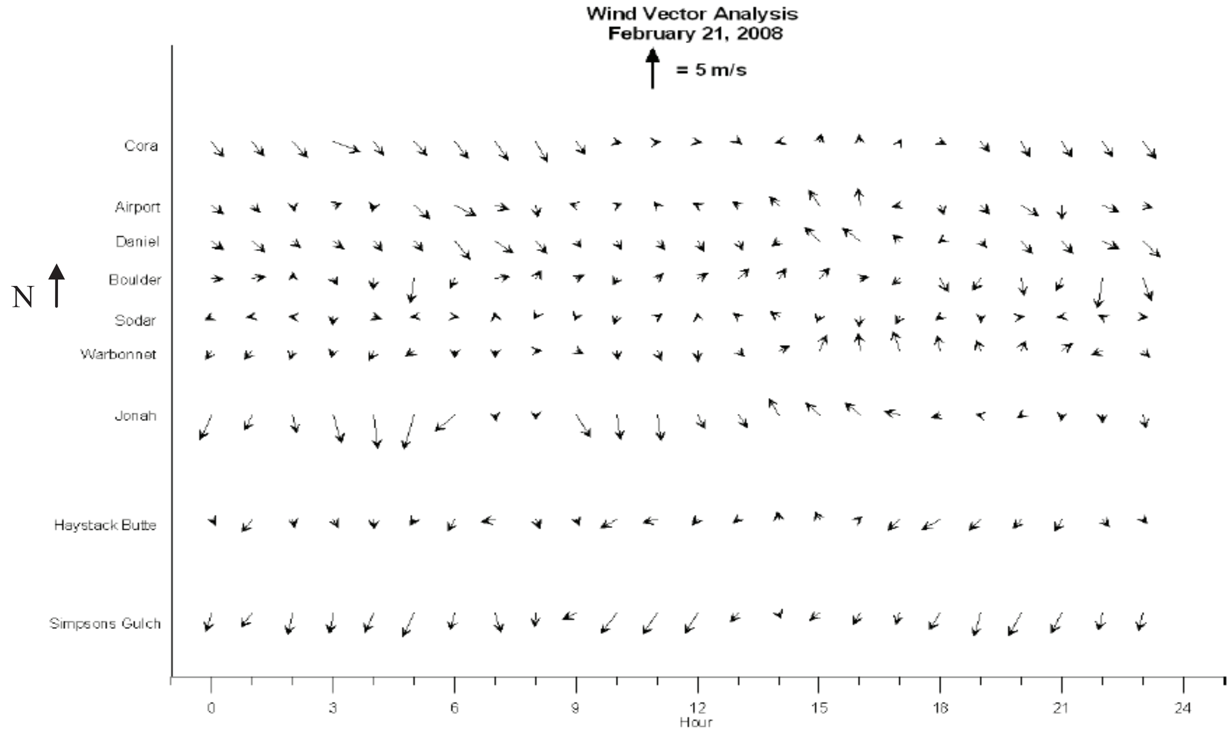


Figure S.7-7. Time-series showing February 21, 2008 hourly wind vectors for monitors used in 2008 field study monitoring network.

As shown in Figure S.7-7, winds on February 20th and 21st were generally light with variable directions throughout the monitoring network. There were two notable exceptions. After midnight, there was a general light northwest flow suggestive of a regional drainage pattern as colder, heavier air from the higher elevations flows downhill.

Generally stronger winds were measured at Jonah in the forenoon hours relative to the other sites in the network; this effect is also sometimes seen at Daniel and is likely due at least in part to the fact that winds at these two sites are measured on a standard 10 meter tower whereas the other sites made use of 3 meter high tripod mounted anemometers. During the afternoon, winds reversed at some sites, shifting to the southeast. This mid-day flow reversal is typical of high ozone days in the UGRB. On February 20, 2008, peak 8-hr ozone concentrations in the 70-85 ppb range were measured at sites throughout the study area; on February 21, 2008, the Boulder monitor recorded a 122 ppb 8-hr average ozone concentration. High ozone continued on February 22, 2008 with the Jonah monitor recording a daily maximum 8-hour average ozone concentration of 102 ppb. Minimal emissions transport and dispersion, due to the light winds in the UGRB, were characteristic throughout the February 19-23, 2008 ozone episode.

The South Daniel FRM monitor which is in the northwest portion of the recommended nonattainment area is typically upwind of local precursor sources and the Boulder monitor. On February 20 ambient nitrogen dioxide (NO_2) concentrations at the Daniel monitor were essentially equal to zero (0) ppb for all 24 hours; very low concentrations of VOCs were also measured in the VOC canister samples collected at Daniel on this day. Nearly identical values were observed at the Daniel monitor and in the Daniel VOC canister samples obtained throughout the ozone episode (February 19-23, 2008); this was also the case during all three IOPs. The canister samples collected at the Daniel monitor in the 2007 field study also showed consistently low VOC concentrations. Additionally, monitored NOx concentrations recorded at Daniel have been very low since this site began operation nearly four years ago; the VOC canister data and the NOx monitoring conducted at Daniel clearly indicate the air coming into this area has low ozone precursor concentrations. Additionally, based on the 2008 field study data at the Daniel monitor, background ozone concentrations during the winter are typically in the 50 - 60 ppb range. Daily maximum 8-hour ozone concentrations at the Daniel monitoring site during the February 19-23, 2008 ozone episode ranged between 62-76 ppb.

One view of the surface wind direction-ozone relationship is shown on Figure S.7-8, which presents a wind rose using measurements from the Boulder monitoring site. This diagram is constructed using the daily peak 8-hr ozone level and 15:00 MST hourly averaged winds. These results show that high ozone levels were associated with afternoon winds from a variety of directions, reflecting the “light and variable” nature of the surface layer winds when the monitored 8-hour ozone levels were above 75 ppb, as opposed to 8-hour ozone concentrations that were less than 75 ppb, which tend to be associated with persistent higher wind speeds and the predominant northwest flow direction along the valley axis.

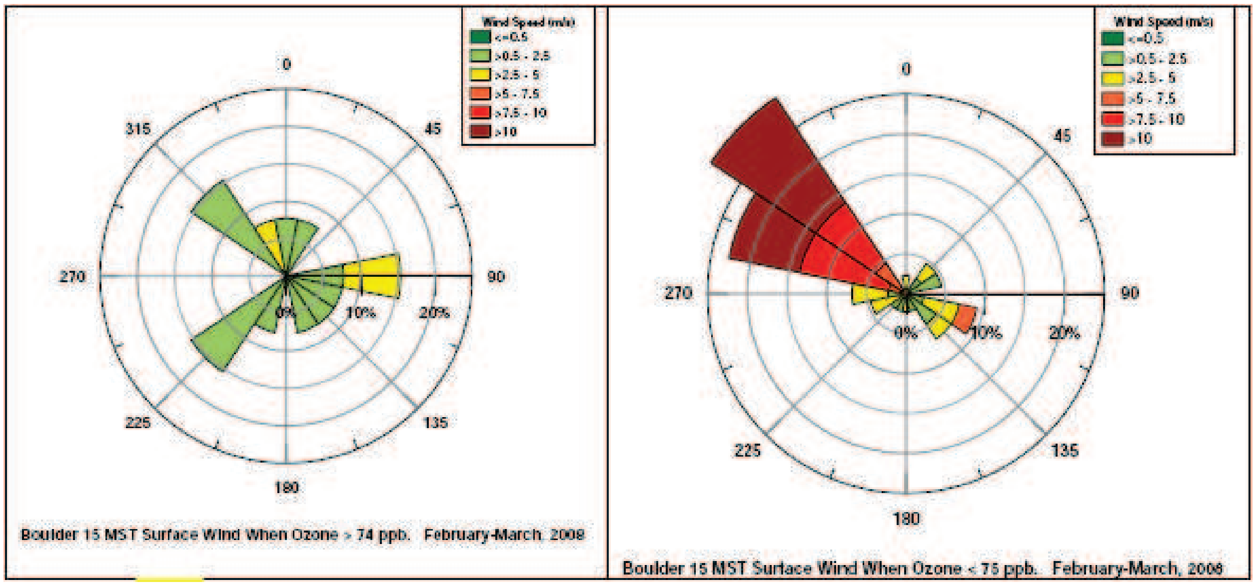


Figure S.7-8. Wind roses based on 15:00 (MST) data from the Boulder site for days with maximum 8-hour average ozone a) greater than 74 ppb (left) and b) less than 75 ppb (right).

Description of Conditions Aloft

A multi-level SODAR was operated continuously at a location approximately 3 miles southwest of the Boulder monitoring site during the 2008 field study. The SODAR provided two types of data: 1) vertical profiles of wind speed and wind direction at 10-meter increments up to 250 meters above ground level, and 2) information which allows an estimation of mixing height (mixed layer depth). The regular hourly observations during the 2008 field study were supplemented with high resolution measurements of vertical wind speed, wind direction, and temperatures during the IOPs. The hourly meteorological data capture rate was excellent. Comparing the measured wind data with peak 8-hour ozone concentrations at Boulder, a strong correlation between ozone concentrations and low mixed layer average wind speeds is evident. Looking at SODAR data on the afternoon of February 21, 2008, a day when 8-hour ozone concentrations above 75 ppb were noted throughout the field study area, reveals a top to the mixing layer at about 100 meters above ground level (AGL) representing a very shallow layer trapping ozone precursors and other pollutants in high concentrations near the surface.

Similar vertical profiles (soundings) and boundary layer development were measured by balloon-borne observations (ozone measurements, temperature, relative humidity and winds) on each of the high ozone days. Stable atmospheric conditions prevailed, and were characterized by strong low-level temperature inversions with very shallow mixing heights and light boundary-layer winds**.** Peak ozone concentrations were often observed somewhat above the surface but still within the stable inversion layer. As shown in Figure S.7-9, at low mixing heights (below 100 meters), the highest values of ozone were observed. Table S.7-2 provides a summary of the days with low-level capping inversions, and the measurements obtained, including the date and time of each balloon launch, the ground temperature and maximum inversion temperature (temperature at top of inversion layer), the difference between the maximum inversion temperature and the ground temperature (inversion layer Delta T), which reflects the strength of the temperature inversion. Note the highest inversion layer temperature measured is 14.5 (^{o}C) and occurs on February 19th.

Launch Date	Launch Time (MST)	Ground Temp (°C)	Max Inversion Temp (°C)	Inversion Layer ΔT (°C)	Inversion Height (meters AGL)
2/18/08	11:00	-3.8	-3.2	0.6	150
2/18/08	16:00	-1.8	-1.7	0.1	47
2/19/08	7:00	-14.8	-0.3	14.5	489
2/19/08	1100	-8.1	1.3	9.4	442
2/19/08	13:00	-5.3	2.2	7.5	403
2/19/08	16:00	-4.5	1.8	6.3	445
2/20/08	7:00	-13.6	-2.4	11.2	398
2/20/08	1100	-13.9	-2.0	11.9	342
2/20/08	13:00	-7.7	-3.2	4.5	449
2/20/08	16:00	-5.4	-2.3	3.1	543
2/21/08	7:00	-17.4	-4.0	13.4	500
2/21/08	1100	-7.9	-3.0	4.9	405
2/21/08	13:00	-3.4	-2.6	0.8	373
2/21/08	16:00	-5.7	-2.9	2.8	494
2/27/08	8:00	-9.7	-1.4	8.3	670
2/27/08	1100	-5.4	0.1	5.5	711
2/27/08	13:00	-2.3	1.0	3.3	608
2/27/08	16:00	-1.2	0.7	1.9	527
2/28/08	8:00	-8.6	-2.3	6.3	149
2/28/08	1100	-1.4	-2.4	-1.0	265
2/28/08	13:00	1.8	0.0	-1.8	91
2/28/08	17:00	0.5	1.0	0.5	190
2/29/08	8:47	-6.2	-2.5	3.7	460
2/29/08	1100	-8.9	-0.3	8.6	396
2/29/08	13:00	-1.4	0.3	1.7	314
2/29/08	16:00	-0.3	1.5	1.8	470
3/10/08	8:00	-12.2	-5.8	6.4	470
3/10/08	1100	-7.6	-5.0	2.6	480
3/10/08	14:00	-1.6	-2.1	-0.5	312
3/10/08	17:00	-1.3	-2.0	-0.7	705
3/11/08	8:00	-13.1	1.3	14.4	373
3/11/08	1100	-2.4	1.5	3.9	312
3/11/08	13:00	2.1	2.0	-0.1	252
3/11/08	17:00	0.5	1.2	0.7	236
3/12/08	8:00	-9.3	-2.1	7.2	142
3/12/08	1100	2.3	2.5	0.2	90
3/12/08	15:00	3.5	-0.3	-3.8	261

Table S.7-2. Summary of low-level temperature measurements, and related data on inversion strength.

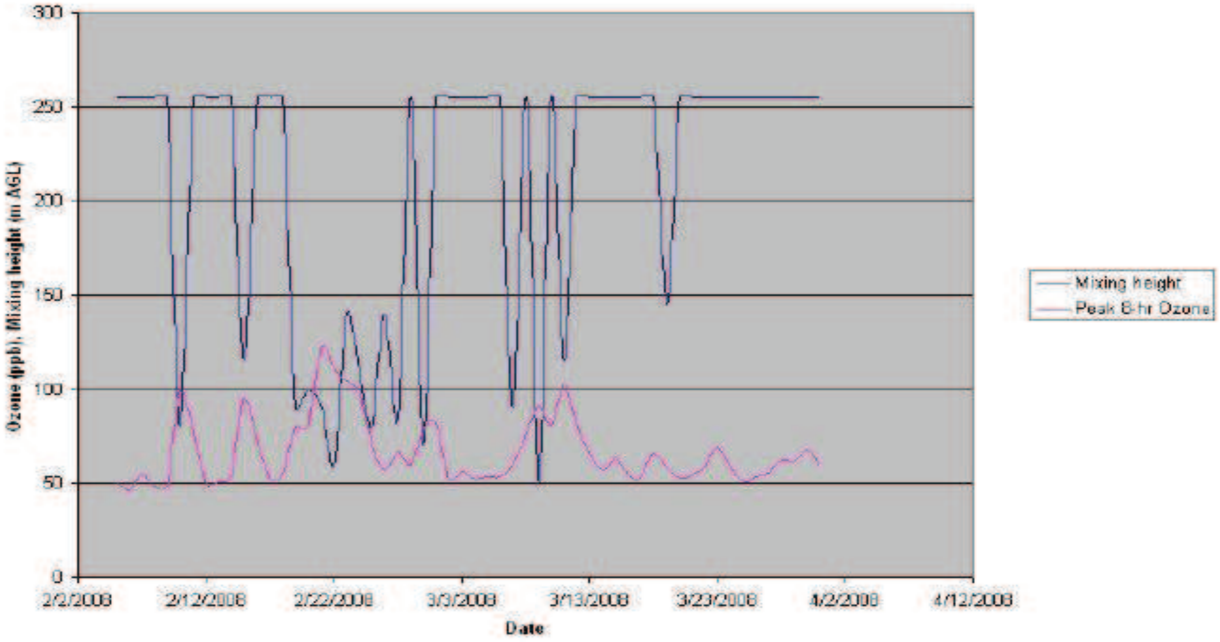


Figure S.7-9. SODAR-reported mixing height versus peak daily 8-hour ozone concentrations at Boulder. Measurements limited to below approximately 250 meters above ground level (AGL).

Soundings taken in the forenoon and afternoon of February 21, 2008 are shown in Figure S.7-10. Profiles for ozone (black line), temperature (red line), dew point temperature (dashed blue line) and winds (vectors) are plotted as functions of height above the ground elevation of the balloon launch site. A strong low-level inversion was present up to 2,500 meters-msl (~ 400 meters-agl) with a maximum temperature at the top of the inversion of -2.9 ^{o}C, several degrees warmer than the temperature at the surface. Boundary-layer winds in the forenoon were light from the west when ozone levels were ~50 ppb, before becoming southeast in the afternoon.

Figure S.7-10 shows the inversion is setting up in the morning of February 21, 2008, and that the inversion persisted through daylight hours, resulting in high ozone concentrations beneath the inversion. Figure S.7-10 also shows that at 11:00 (MST) ozone concentrations were ~ 50 ppb below the inversion height of 2,500 meters (MSL) which is shown by the green circle (left pane) towards the bottom of Figure S.7-10; measured ozone levels above the inversion layer were also generally ~ 50 ppb.

Normally, some vertical mixing of the air would exist, as the temperature aloft begins to fall off with increasing height above ground; however, the strong surface-based inversion persists to 4:00 pm, effectively inhibiting vertical mixing. A shallow layer of high ozone (> 110 ppb) was present in the afternoon (16:00 MST) sounding, which is shown by the green oval (right pane) towards the bottom of Figure S.7-10. Ozone concentrations decrease rapidly with height below the inversion; ozone levels above the inversion are about 50 ppb. Note that the vertical wind shear measured at the top of the inversion layer height above ground (wind arrows on the right side of graphs) attest to the complete decoupling of the boundary layer air from layers aloft.

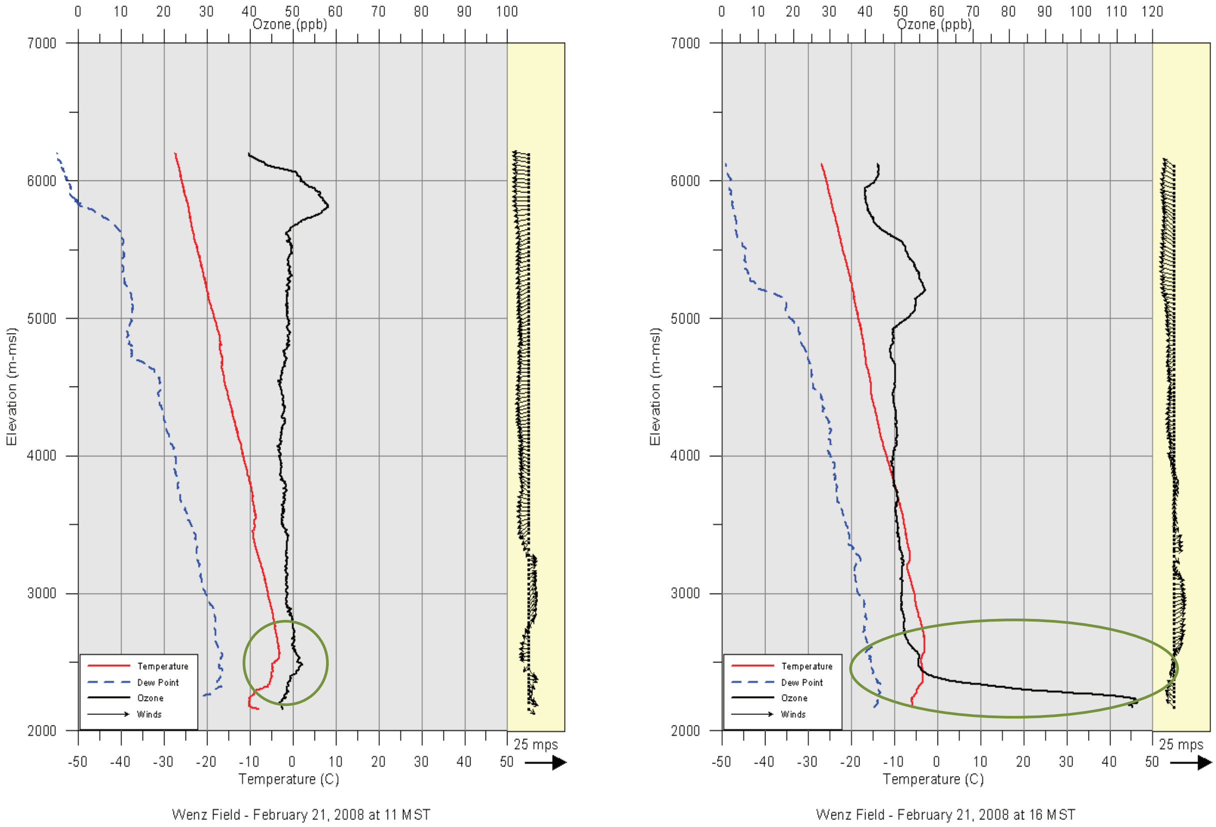


Figure S.7-10. February 21, 2008 balloon-borne soundings; Sounding at 11:00 (MST) (left); Sounding at 16:00 (MST) (right).

Tools to Evaluate Air Parcel Transport: HYSPLIT vs. AQplot Back Trajectory Analyses

Trajectory analyses were used to determine possible air parcel transport into the UGRB during February 20, 2008, as a means of evaluating possible precursor emissions and ozone transport in the UGRB and at the Boulder and Jonah monitors.

The HYSPLIT (HYbrid Single-Particle LaGrangian Integrated Trajectory) model is a trajectory model that is used for computing simple air parcel trajectories. HYSPLIT can use meteorological data from several archived meteorological modeling databases, including the NCEP Eta Data Assimilation System (EDAS), which is based on a 40 kilometer resolution data (2004-present). However, 40 kilometer (km) data may not provide sufficient resolution to resolve the significant terrain features that influence the wind flow patterns in the UGRB. The result of using such low resolution data to represent the terrain features in and surrounding the UGRB will be that the modeled terrain will be much smoother, and will not match the actual terrain (see Figure S.7-11). This will affect the wind trajectory analysis because the roughness of the terrain as well as terrain blocking and channeling effects may not be well represented, which would otherwise influence the wind speeds and the trajectory path lengths. In very complex terrain, such as in the UGRB, the HYSPLIT model trajectories may not be very accurate unless the local wind flow patterns are being driven by the large-scale synoptic conditions (e.g., strong winds).

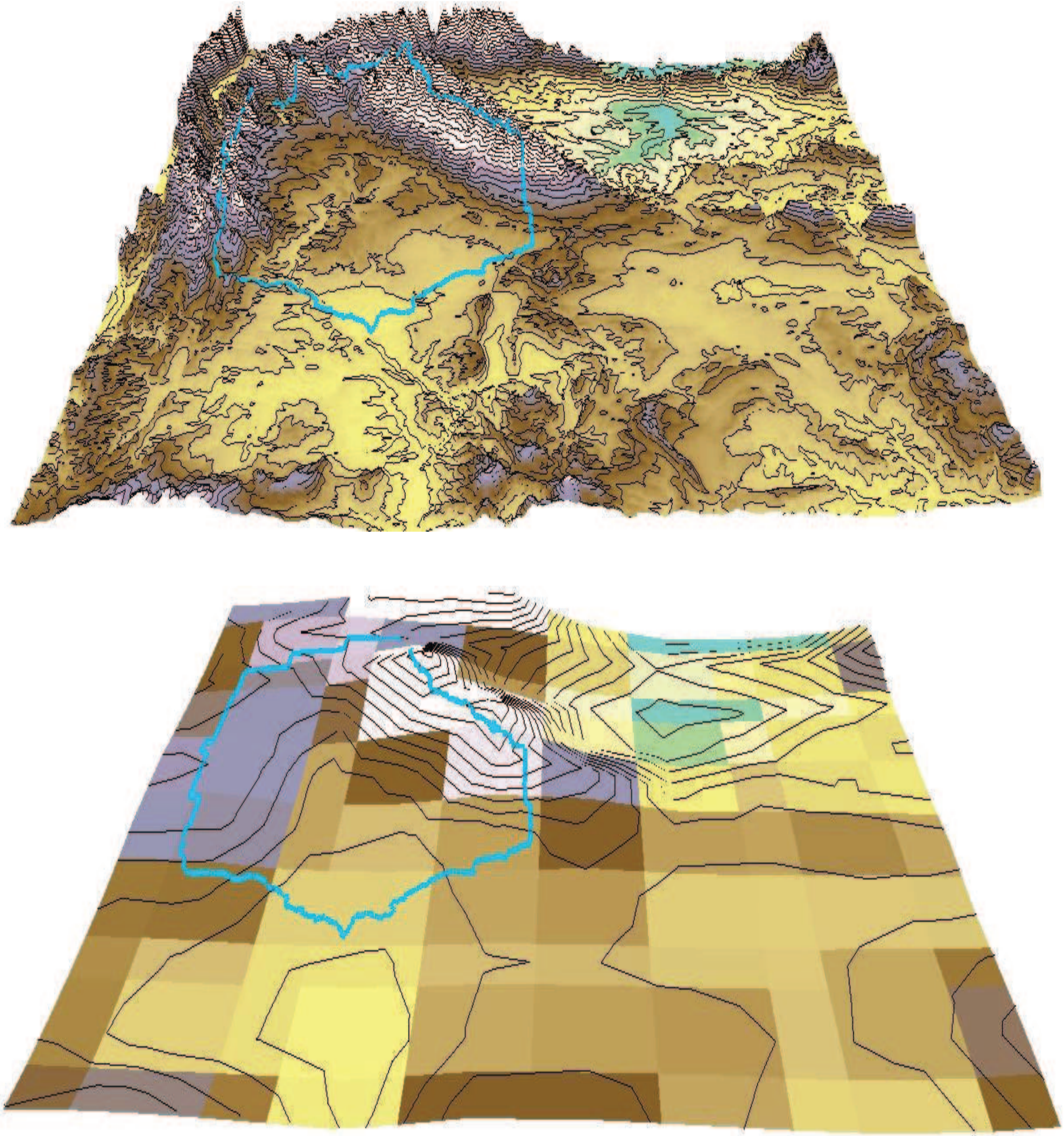


Figure S.7-11. A comparison of the local terrain features at 1 km and 40 km resolution, respectively, and the resulting "smoothed" terrain as shown in the 40 km 3-D topographic plot.

Figure S.7-12 shows a similar comparison of the local terrain features at 1 km and 40 km resolution as depicted in the 2-dimensional contour plots. Note the terrain features in the bottom pane are much less resolved (less terrain detail and decreased roughness) than those terrain features as shown in the top pane.

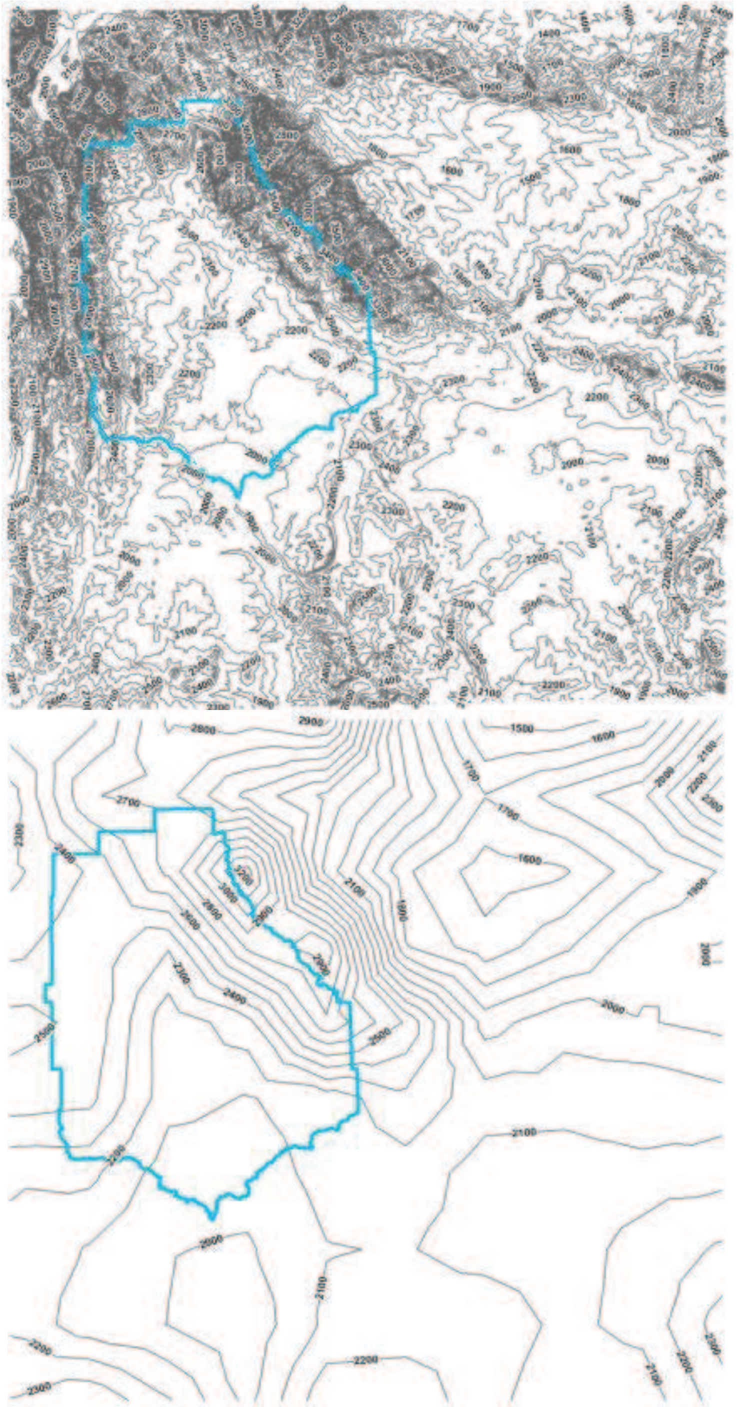


Figure S.7-12. A comparison of the local terrain features at 1 km and 40 km resolution, respectively, as depicted in the 2-D contour plots.

While the trajectory model is a useful tool in assessing approximate air parcel movement, and can be used to better understand potential pathways for pollutants moving within and into and out of the UGRB, trajectories are a highly simplified representation of the complex, two- and three-dimensional transport and turbulent diffusion processes that move pollutants from place to place. Thus, a particular trajectory path is subject to uncertainty and should not be interpreted as an exact representation of actual pollutant transport. Generally, the longer an air mass is tracked forward or backward in time, the more uncertain is its position (Kuo et al., 1985; Rolph and Draxler, 1990; Kahl and Samson, 1986).

Additionally, the trajectory model error is a function of the complexity of the meteorological scenario under study. In this analysis, the strong surface-based inversion layer in place on February 19-22, 2008 results in a decoupling of the upper air layers (above the inversion layer) and the lower air layers (below the inversion) and winds in the upper and lower layers will at times blow in different directions at different speeds. Winds are light and variable in the lower layer, adding to the complexity of the situation. This very complex meteorological scenario is difficult to represent accurately in a trajectory model.

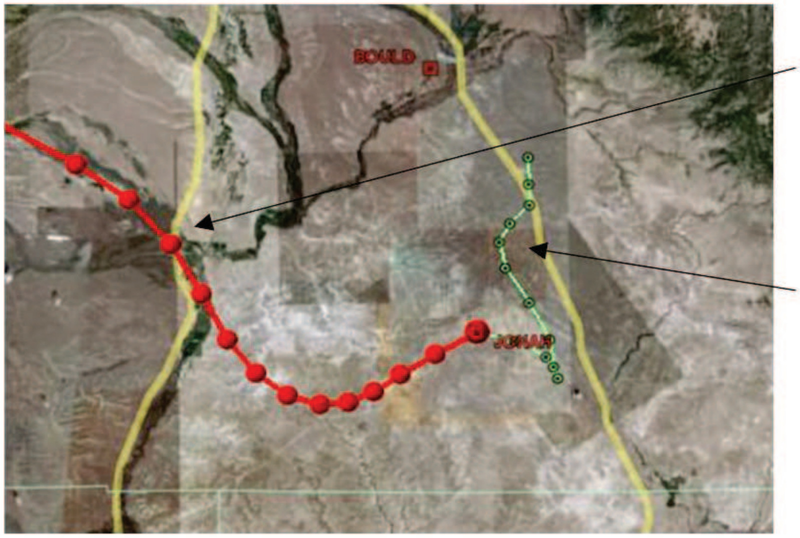
AQD ran a comparison of 12-hour back trajectories from the Jonah and Boulder monitoring sites, using the HYSPLIT model with the EDAS 40 kilometer meteorological data, and AQplot, (a 2-dimensional trajectory model) using actual meteorological data from the Jonah and Boulder monitoring sites, respectively. This comparison shows that much different back trajectories are produced by these two models, as shown in Figures S.7-13 and S.7-14. The 2-dimensional trajectory model (AQplot), used in these analyses, was developed by the Texas Commission on Environmental Quality.

Additional trajectory analyses using a 3-D trajectory model are discussed in the next section. However, for this particular comparison, a 2-D trajectory model is an acceptable model to assess trajectories near the monitoring sites because the surface winds in the UGRB under these episodic winter conditions have been effectively decoupled from the upper air layers. The amount of vertical air movement is limited due to the capping inversion in place – in other words, the movement of air parcels below the inversion is not influenced by winds above the inversion, and there is little vertical mixing of air near the ground. Monitoring data of the localized meteorological patterns in the proposed nonattainment area boundary show that under these episodic conditions, the wind patterns are 2-dimensional, and the use of the 2-D AQplot trajectory model for this particular application is reasonable under these winter meteorological conditions (inversion, low mixing height, and stable atmosphere) as the air parcel trajectories start off and tend to stay close to the ground.

As shown in Figures S.7-13 and S.7-14, the resulting short trajectories never get very far away from the monitor site; considering the short duration of the trajectory analysis, less interpolation error would be expected. The HYSPLIT model does not consider the wind influences as measured in the 2008 field study surface monitoring network; the AQplot local-scale back trajectories are a more accurate depiction of what is going on because of the input of local data.

- **Trajectories ending 14:00 MST at Boulder on 20 February 2008**
- **Markers at 1-hour intervals; 12 hours total**
- **Very light, meandering surface winds at Boulder not reproduced by EDAS 40 km data set**

Figure S.7-13. Comparison of HYSPLIT (red) and AQplot (pink) 12-hour back trajectories from the Boulder monitoring site on February 20, 2008.



- **Regional-scale model: HY-SPLIT back trajectories using 40 km resolution EDAS**
- **Local scale: UGWOS ’08 surface wind data (markers at 1-hour intervals)**

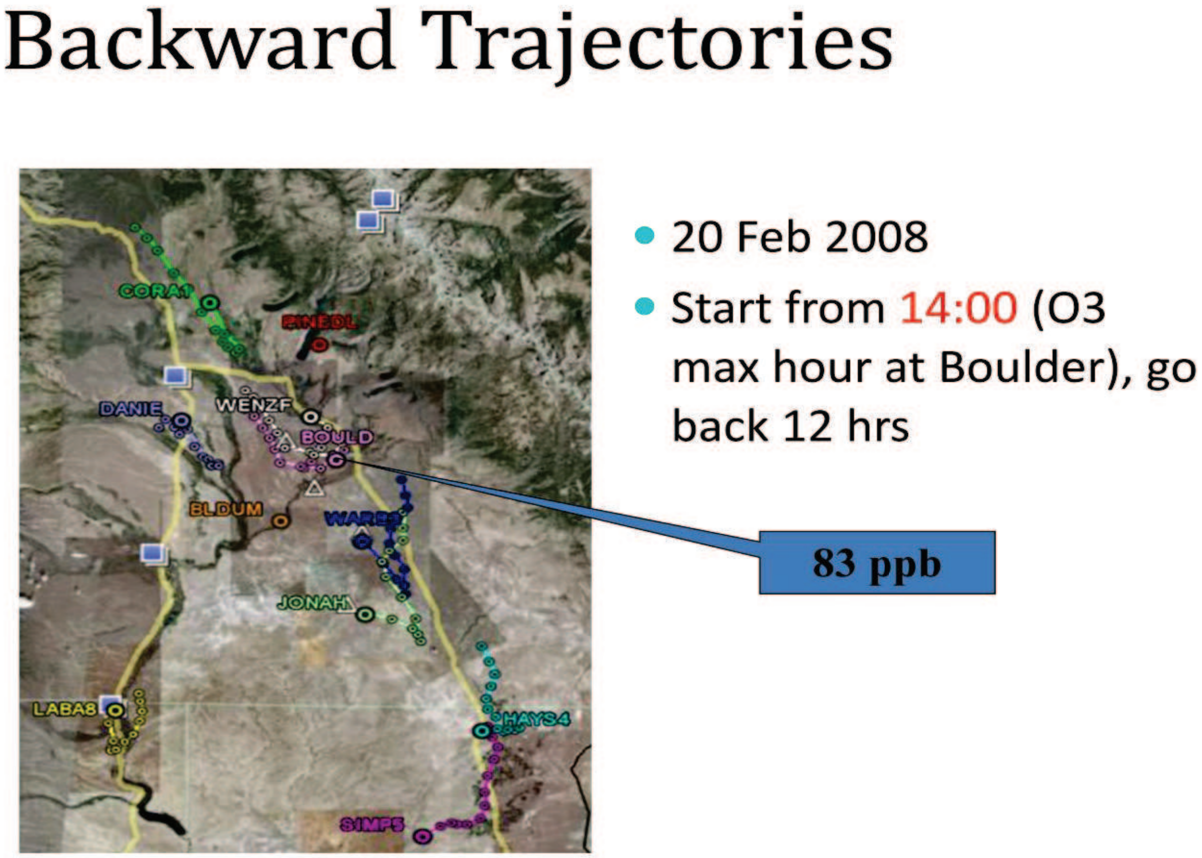
- **20 February 2008: 14:00 MST surface back trajectory from Jonah**
- **Markers at 1-hour intervals; 12 hours total**

Figure S.7-14. Comparison of HYSPLIT (red) and AQplot (green) 12-hour back trajectories from the Jonah monitoring site on February 20, 2008.

This comparison demonstrates that the HYSPLIT model overestimates the back trajectory path length because the localized low wind speed conditions and the wind flow reversal are not reproduced in 40 kilometer EDAS meteorological analysis fields. Additionally, the HYSPLIT model trajectory shows a less dramatic shift in wind direction and much higher wind speeds leading to a completely different result. A trajectory model that accurately reflects the terrain influence, sustained low wind speeds, and local-scale observed wind flow patterns was needed to effectively evaluate air parcel transport throughout the UGRB under these episodic conditions.

AQplot Back Trajectory Analysis

Back trajectories using the AQplot model and the meteorological data collected during the field study on February 20, 2008 are shown in Figure S.7-15; the trajectories were used to evaluate air parcel movement near the monitors during the 12 hours leading up to the February 20, 2008 monitored high ozone concentrations. These back trajectories start at 2:00 pm (MST), and show that the wind patterns leading up to the afternoon high monitored ozone concentrations at the Boulder monitoring site (and other monitors in close proximity to the Boulder monitor) produce short trajectories, with the air parcels remaining in close proximity to these monitors during this 12-hour period, due to the observed low wind speeds and recirculation patterns (wind reversals).



Backward Trajectories

- 20 Feb 2008
- Start from 14:00 (O3 max hour at Boulder), go back 12 hrs

83 ppb

Figure S.7-15. 12-hour back trajectories near field study monitors on February 20, 2008.

Due to the complexity of the winds in the UGRB during February 19-23, 2008, including the significant terrain-dominated effects on localized winds, stable conditions, and wind flow reversals, as discussed, and the terrain-dominated regional meteorology outside of the UGRB, a high resolution 3-dimensional (3-D) wind field was needed that could correctly reproduce:

1) Shallow inversions and near-field wind flow patterns as measured at the SODAR, which is near the Boulder monitor; and
2) Regional-scale wind flow patterns.

This particular wind field would be utilized in conjunction with a full 3-D trajectory model to evaluate:

1) Air parcel movement in the study area;
2) Influences from the surrounding regional terrain on air parcel movement;
3) Air parcel inflow (ozone or precursor emissions transport) into Sublette County on the days leading up to and during the February 19-23, 2008 ozone episode.

AQD contracted out the development of a 3-D CALMET wind field to evaluate the above, which is discussed in the following section.

CalDESK Trajectory Analysis

AQD developed a high resolution (spatial and temporal) 3-dimensional wind field that uses the National Center for Environmental Prediction (NCEP) Rapid Update Cycle (RUC) model at 20 kilometer resolution, coupled with the high resolution observational database of surface and upper air meteorological data measurements obtained during the 2008 field study. It should be noted that the terrain elevation data used in this wind field is based on much higher terrain resolution than is currently used in the HYSPLIT model. The RUC and field meteorological data were processed through the CALMET diagnostic wind model to generate a 1 kilometer gridded wind field, using high resolution terrain and land use/land cover data, and actual observations of daily snow cover to account for actual snow cover (and albedo effects) within the CALMET domain. The complexity of the terrain, as represented in this 3-dimensional (3-D) CALMET wind field in shown in Figure S.7-16.

This CALMET wind field was developed to evaluate the ozone episode-specific meteorology associated with the February 18-23, 2008 ozone episode. The CALMET domain was set up using the same meteorological modeling domain (464 km x 400 km) developed for the Southwest Wyoming Technical Air Forum (SWWYTAF) modeling analyses (1999), with increased vertical resolution to total 14 vertical layers; the lower layers having small vertical depths in order to better resolve complex flow patterns and temperature inversions near the surface.

Figure S.7-17 provides a snapshot of the wind field based on the winds at 4:00 am (MST) on February 20, 2008, and shows the complexity of the terrain surrounding the UGRB is very well represented in the CALMET wind field. The wind field captures the strong terrain-dominated down slope winds during the early morning hours, and the strong channeling and drainage effects which are exhibited throughout the UGRB – CALMET "sees" the influence of the terrain.

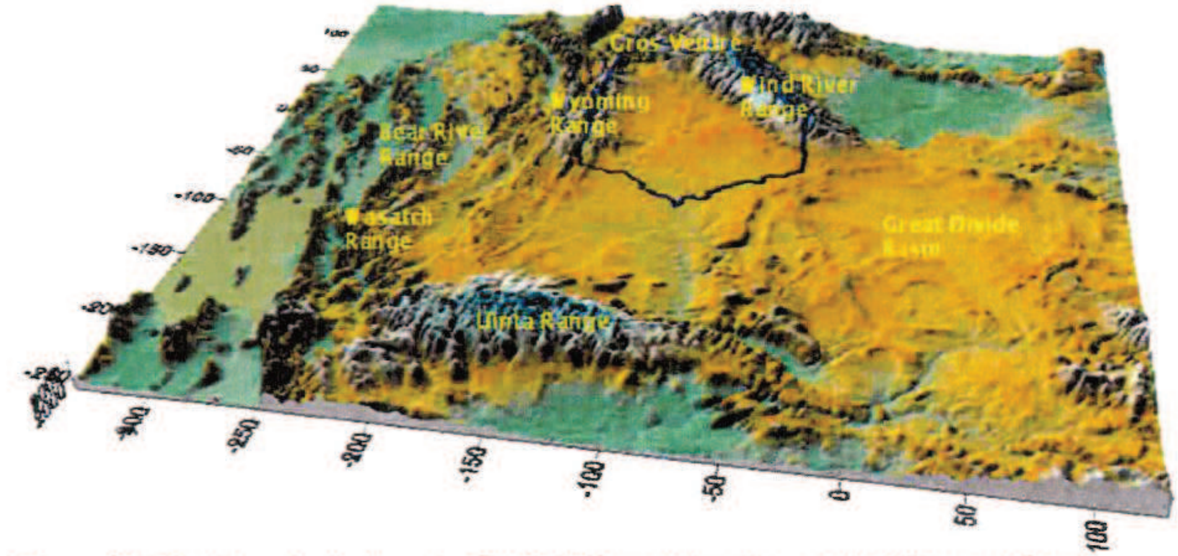


Figure S.7-16. Terrain features in CALMET modeling domain (464 km x 400 km).

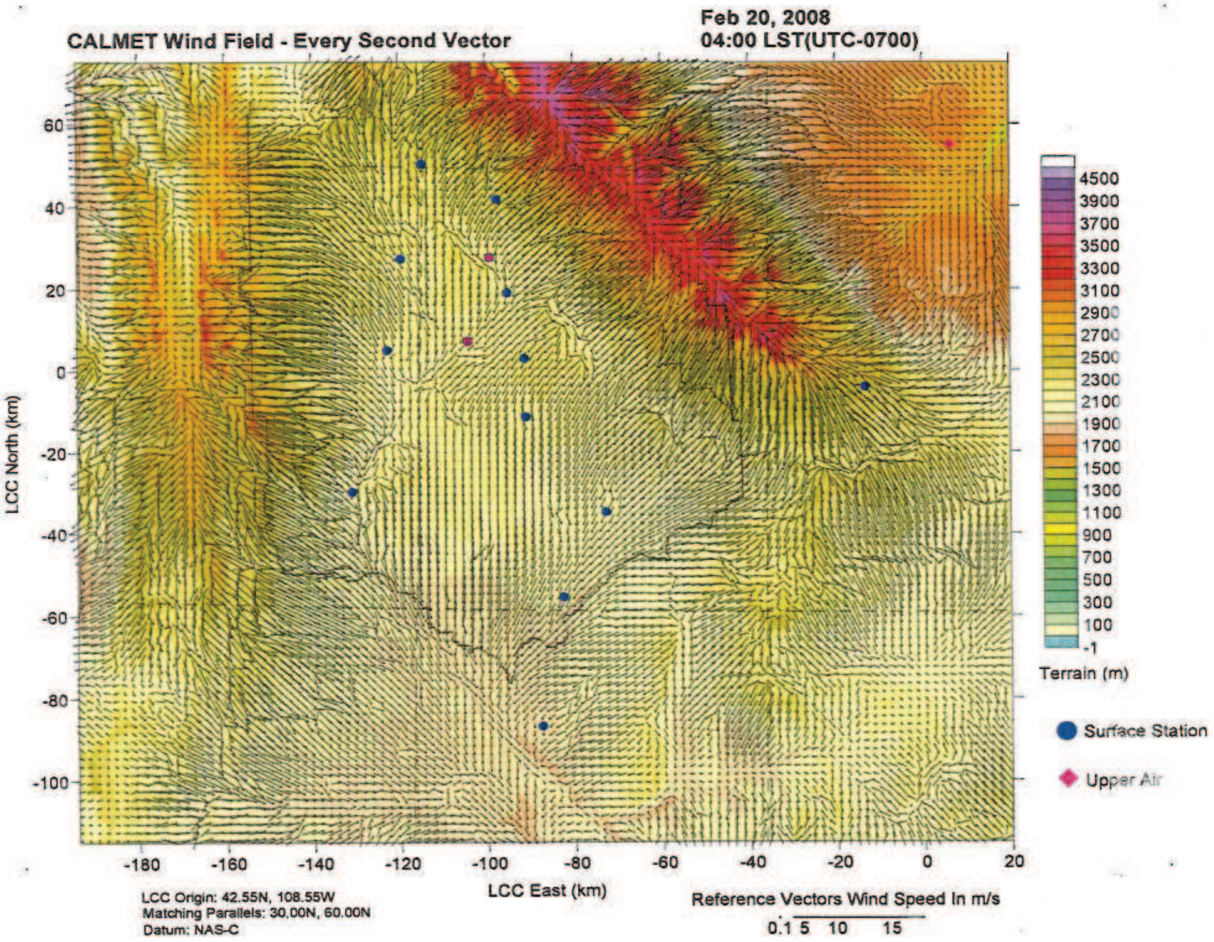


Figure S.7-17. CALMET wind field at 4:00 am (MST) on February 20, 2008. The 2008 field study meteorological monitoring sites are shown for reference.

The 3-D CALMET wind field accurately depicts meteorological conditions in the UGRB and surrounding area. A detailed report discussing the development of the CALMET wind field and the validation of the wind field compared to observations, entitled, "Upper Green River Winter Ozone Study: CALMET Database Development Phase I" will be posted on the DEQ web site and will be sent under separate cover to EPA shortly. Validation of this wind field has shown that the local-scale observed meteorological conditions are being reproduced:

- Temperature lapse rates associated with inversion conditions and low mixing heights
- Wind speeds and wind reversals
- Duration of down slope winds, which last until approximately mid-day before reversing to a generally southeasterly wind flow pattern

The trajectory analyses using this wind field lead to the conclusion that regional transport is insignificant, and local-scale precursor emissions transport is the dominant means of precursor transport during the high ozone periods. The trajectory analyses that follow were a key factor in selection of an appropriate southern boundary of the nonattainment area. The trajectory analyses demonstrate that the proposed southern boundary of the nonattainment area is reasonable, and that there is no significant contribution of ozone or ozone precursors from areas or sources outside the proposed nonattainment area during elevated ozone events.

Specific Examples of Trajectory Analyses Using CalDESK

Based on this wind field, AQD used the CalDESK visualization software to run forward trajectory analyses to evaluate air parcel transport into and out of the UGRB, specifically with respect to air parcels from large stationary sources (power plants and Trona plants) located to the south of the UGRB, and to evaluate the southern extent of air parcel inflow into the UGRB. A series of CalDESK forward trajectory analyses follow, along with a brief discussion of the resulting trajectories generated by CalDESK during February 18-23, 2008. CalDESK Forward Trajectory Analyses (FTA) for February 18, 2008 are shown in Figures S.7-18 through S.7-22.

NOTE: Trajectory figures (Figures S.7-18 through S.7- 49) are being updated to show the proposed nonattainment area boundary. Those figures will be available shortly. AQD will send those figure to EPA as replacement pages.

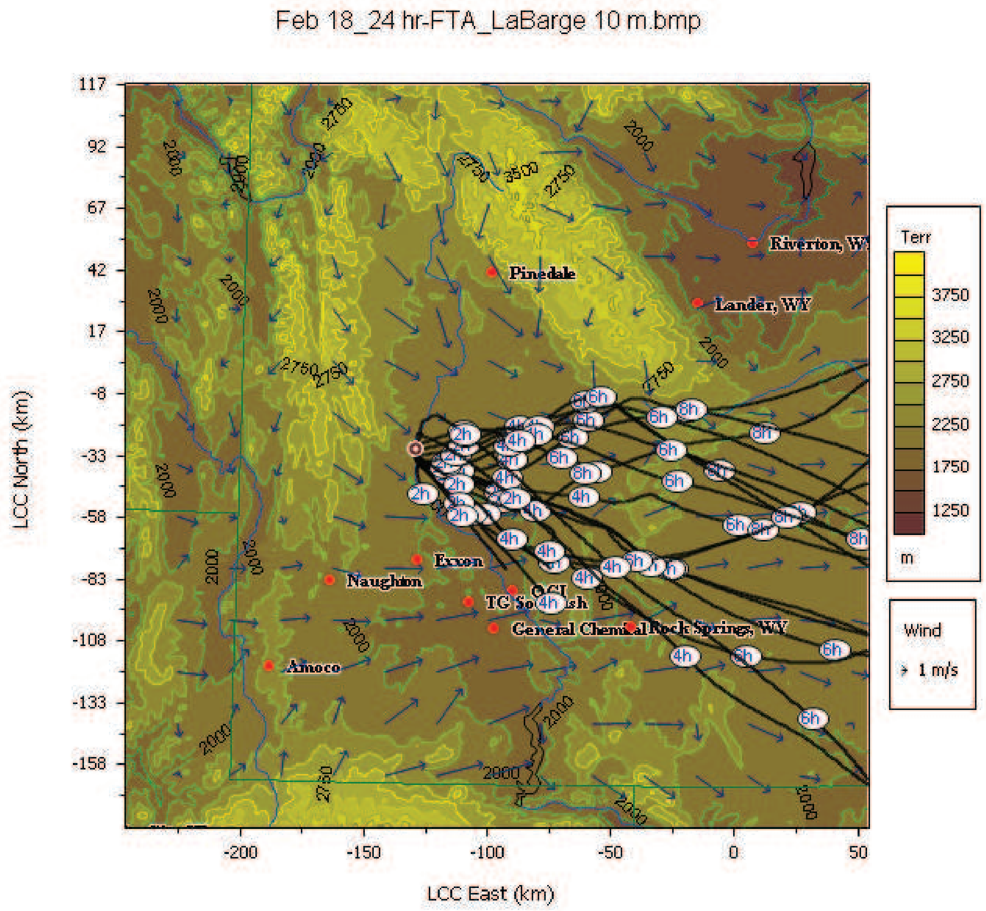


Figure S.7-18. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 18, 2008.

As shown in Figures S.7-18 through S.7-22, the prevailing northwest winds within the UGRB on this day limit air parcel transport into the UGRB from sources located south of Sublette County, which is reflected in the trajectory analysis for the LaBarge and Moxa Arch areas, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant. Additionally, the wind speeds at the monitoring sites on the Pinedale Anticline were also generally high and reflect the prevailing northwest winds typical of the study area during most of the year. This moderately strong, organized northwest flow does not extend to the field study southern monitoring sites (Haystack Butte and Simpsons Gulch); these southern monitoring sites experienced a generally westerly wind. The 2008 field study monitoring sites are shown in Figure S.7-1.

Wind speeds were generally high throughout the monitoring network on February 18th. These conditions continued throughout the night until the early morning of February 19th. Winds decreased significantly thereafter becoming light and variable for the remainder of the day, setting the stage for the next several days. Ozone levels were relatively low, in the 50 ppb range on February 18th; increasing on February 19th, with both the Boulder and Jonah monitoring sites experiencing 8-hr peaks of 80 ppb.

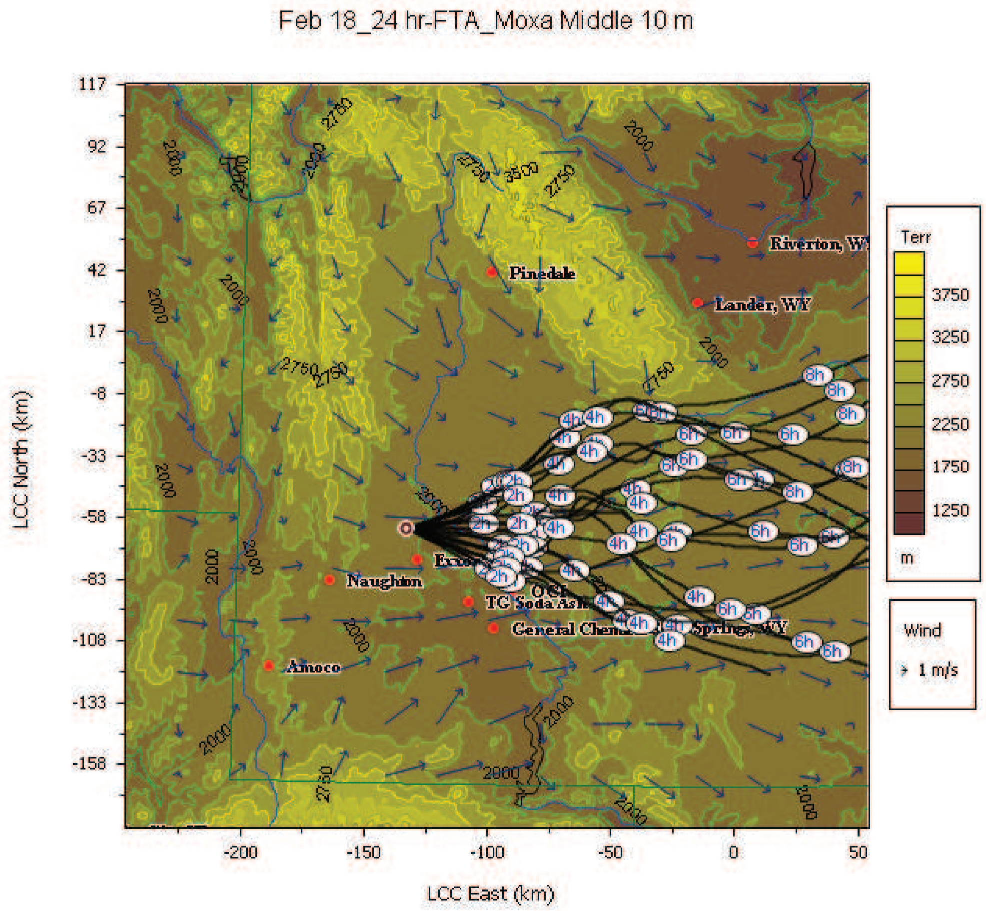


Figure S.7-19. 24-hour forward trajectory analysis in the Moxa Arch area on February 18, 2008.

The trajectory analysis shown in Figure S.7-19 places the initial air parcel release point in the northern part of the Moxa Arch field. The predominant paths shown trend to the east, and there is a slight northerly component to several of the modeled trajectories. These trajectories generally parallel the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory paths lie within the proposed nonattainment area, none of the paths indicate that sources within the Moxa Arch cause or contribute to elevated ozone levels within the proposed nonattainment area.

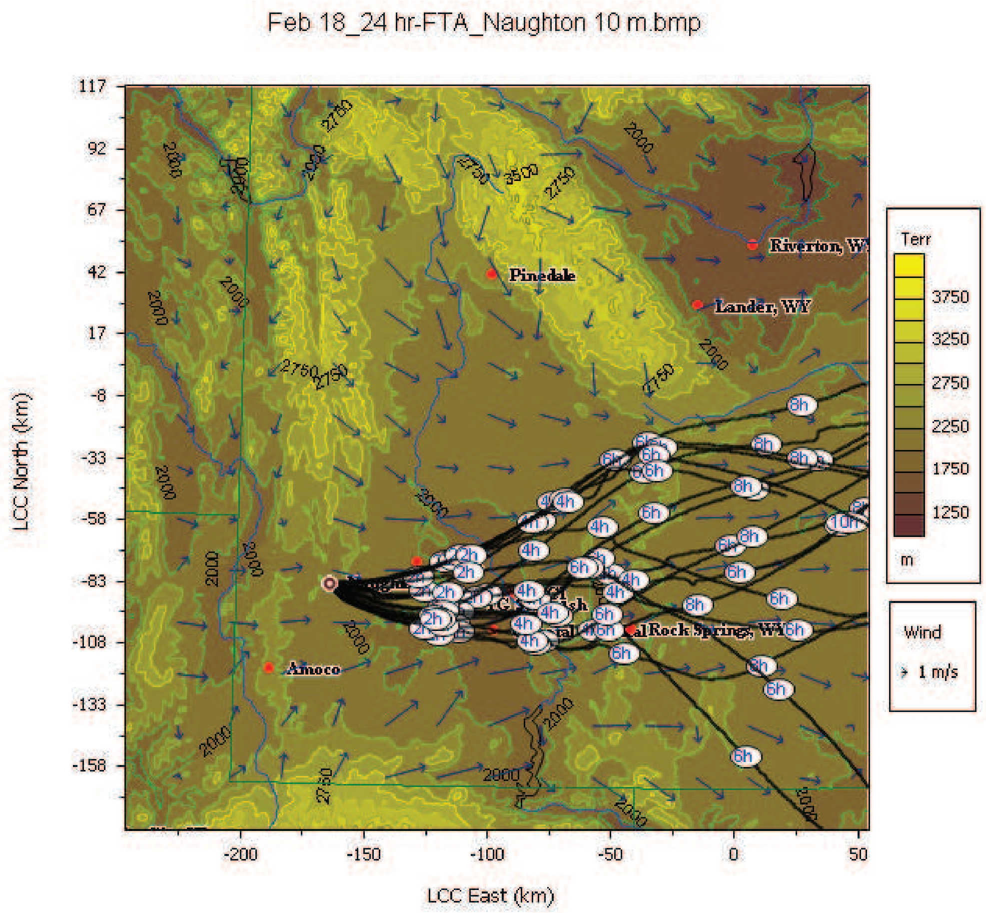


Figure S.7-20. 24-hour forward trajectory analysis at Naughton power plant on February 18, 2008.

The trajectory analysis in Figure S.7-20 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

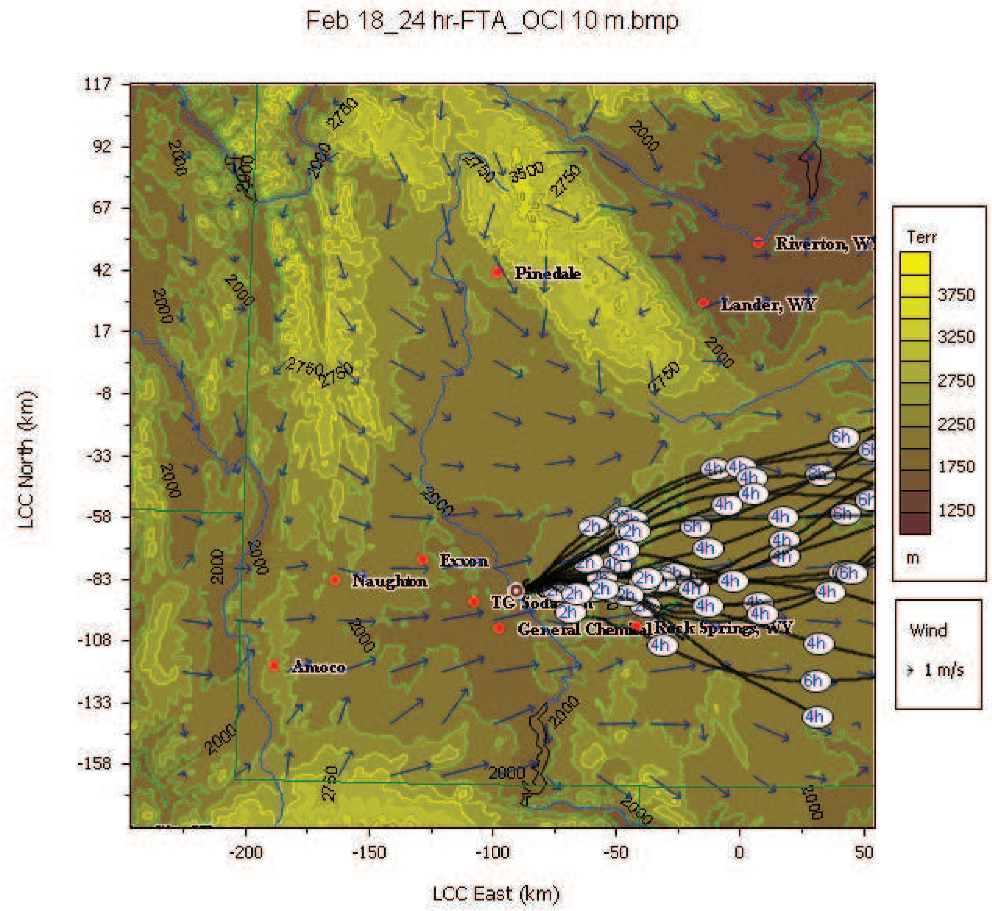


Figure S.7-21. 24-hour forward trajectory analysis at OCI Trona plant on February 18, 2008.

The trajectory analysis in Figure S.7-21 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

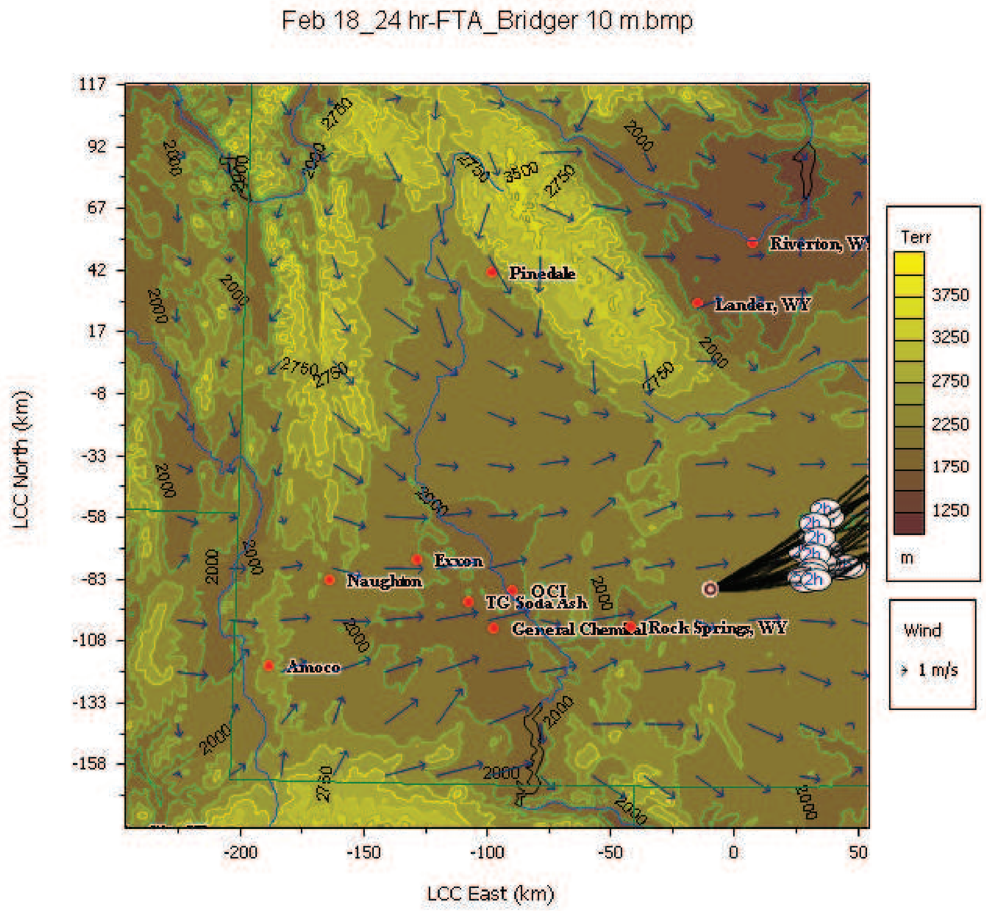


Figure S.7-22. 24-hour forward trajectory analysis at Bridger power plant on February 18, 2008.

The trajectory analysis in Figure S.7-22 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 19, 2008 are shown in Figures S.7-23 through S.7-29.

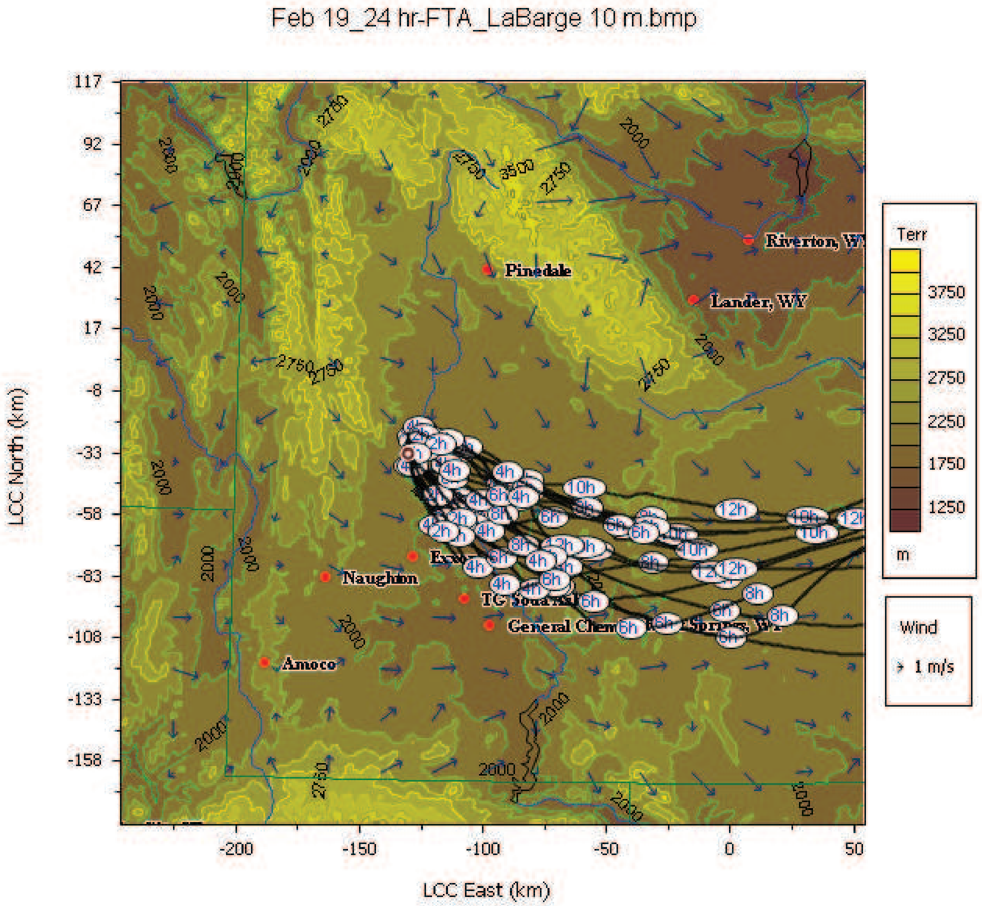


Figure S.7-23. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 19, 2008.

As shown in Figures S.7-23 through S.7-27, the prevailing northwest winds on February 19th continue to limit air parcel transport into the UGRB from the south, which is reflected in the trajectory analysis for the LaBarge and Moxa Arch areas, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

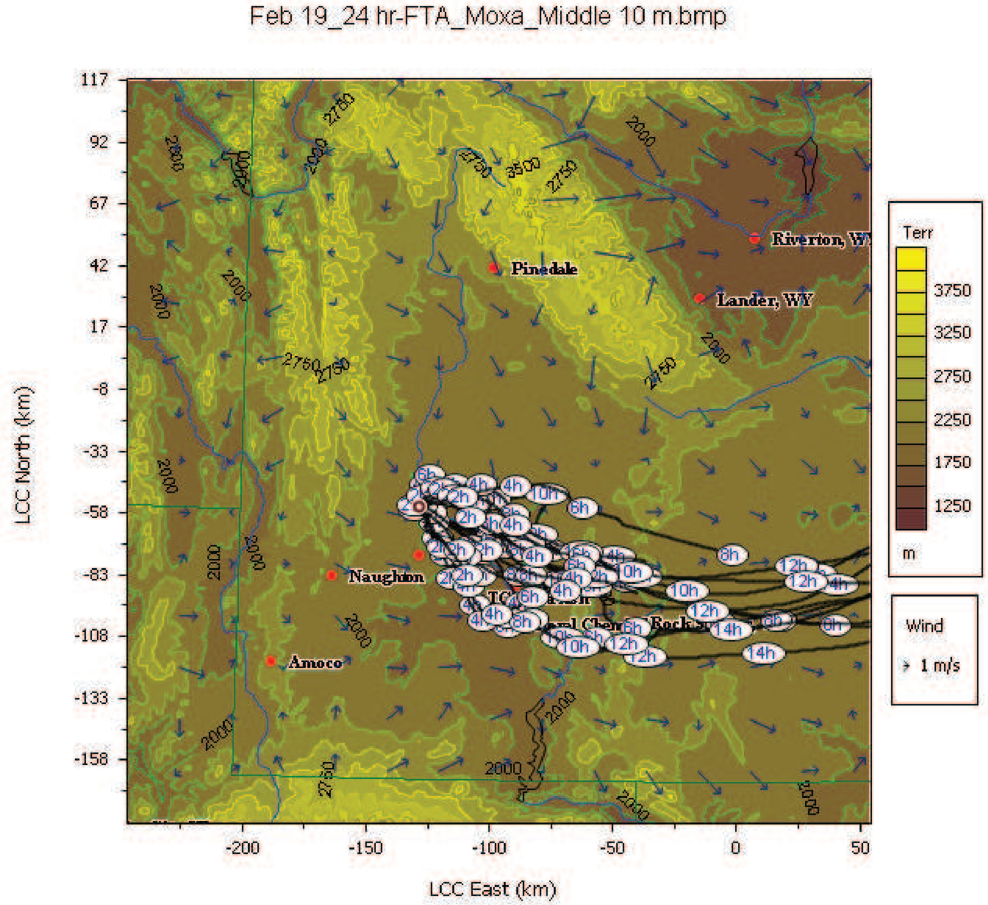


Figure S.7-24. 24-hour forward trajectory analysis in the Moxa Arch area on February 19, 2008.

The trajectory analysis in Figure S.7-24 shows all modeled trajectories from Moxa Arch not entering the proposed nonattainment area.

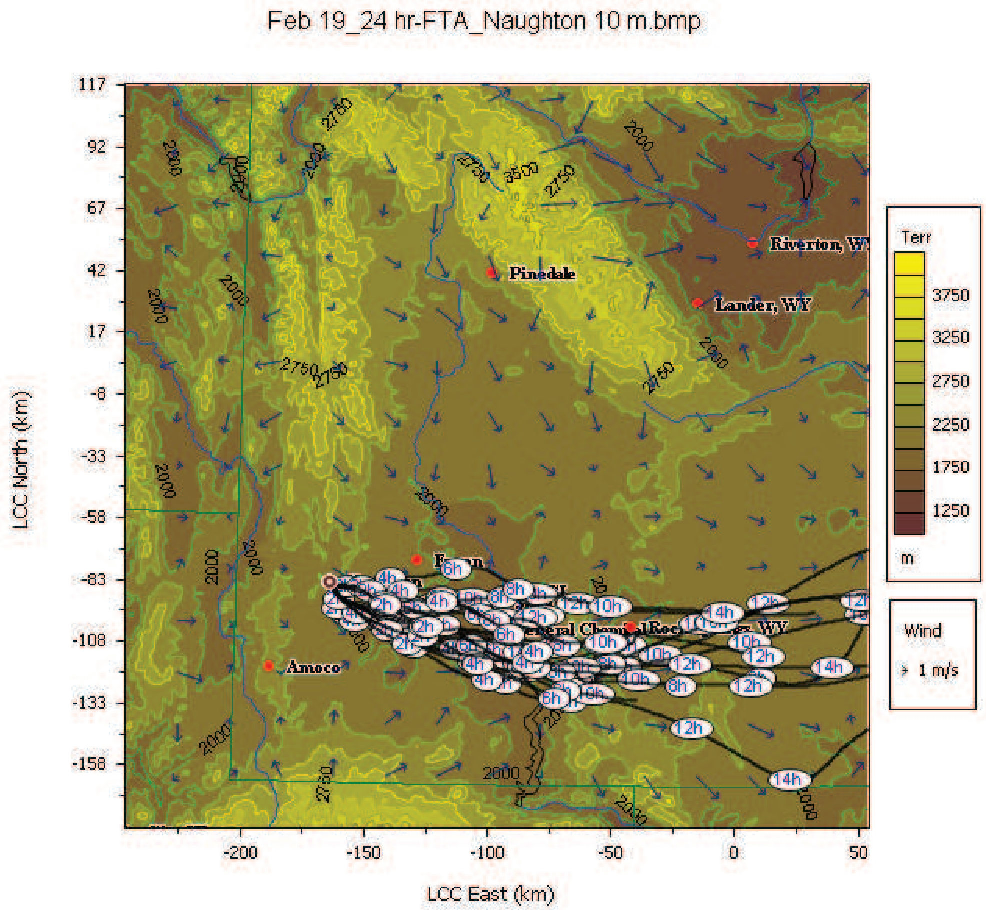


Figure S.7-25. 24-hour forward trajectory analysis at Naughton power plant on February 19, 2008.

The trajectory analysis in Figure S.7-25 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

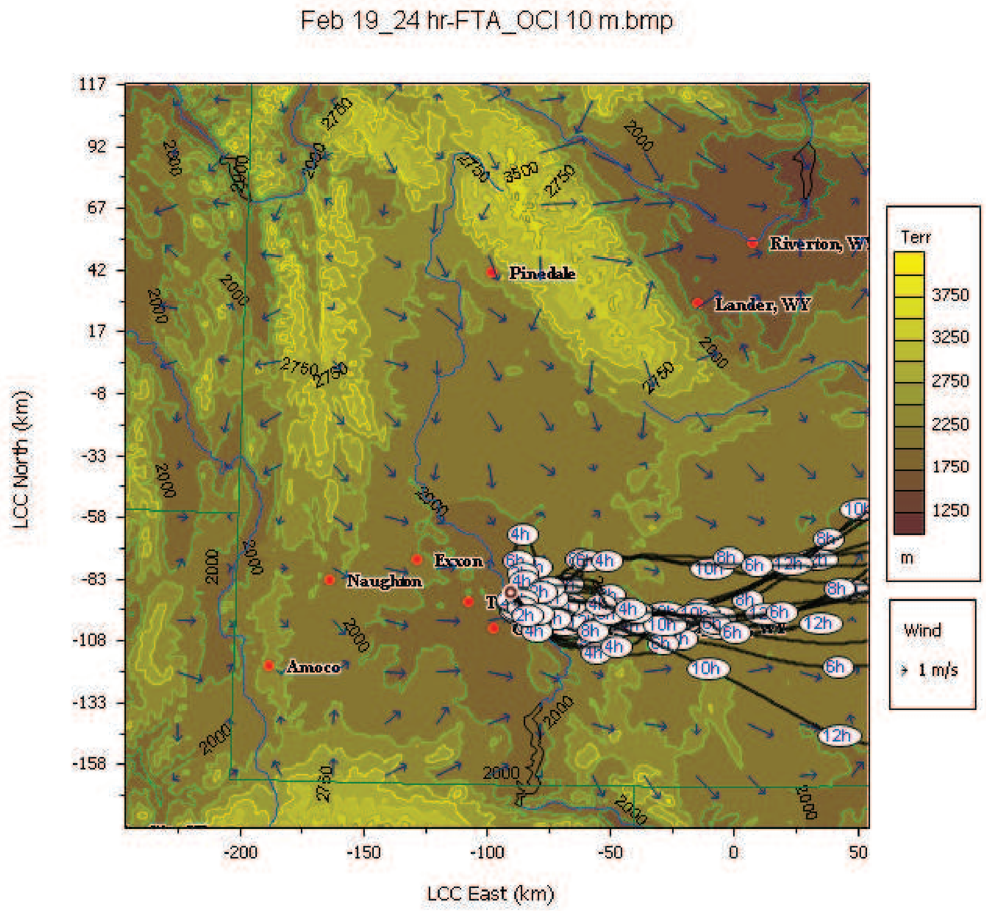


Figure S.7-26. 24-hour forward trajectory analysis at OCI Trona plant on February 19, 2008.

The trajectory analysis in Figure S.7-26 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

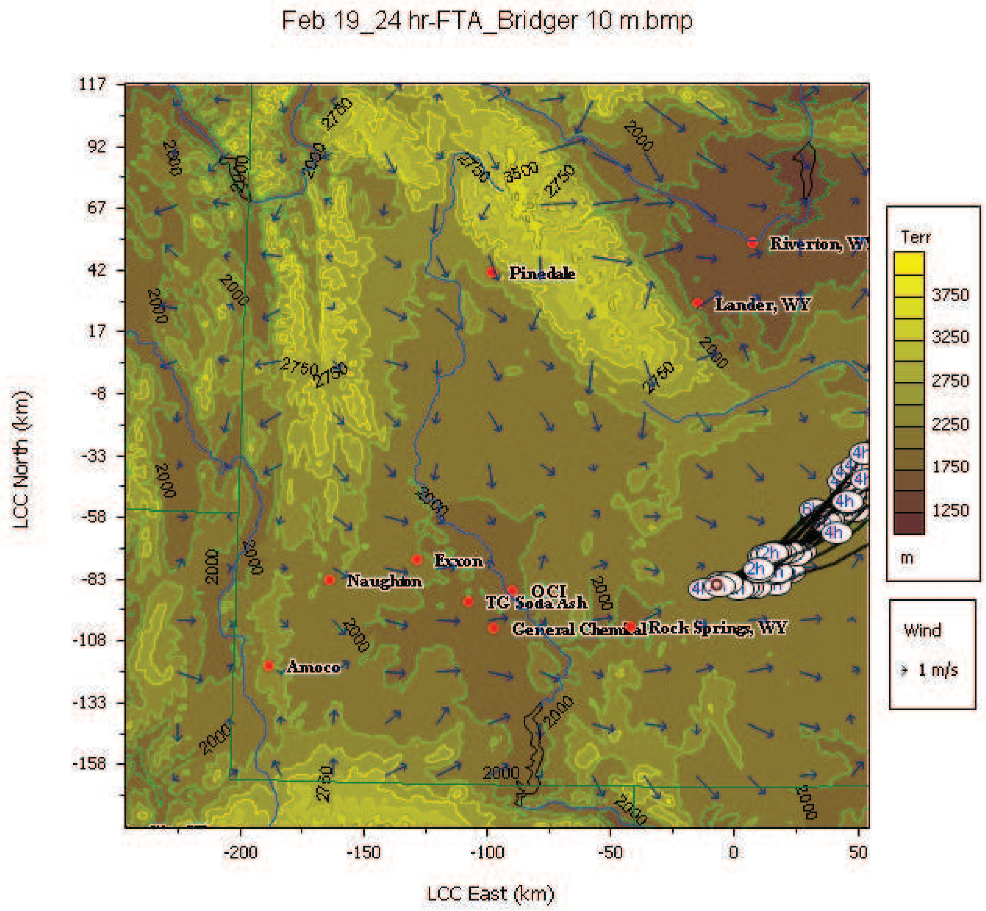


Figure S.7-27. 24-hour forward trajectory analysis at Bridger power plant on February 19, 2008.

The trajectory analysis in Figure S.7-27 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 20, 2008 are shown in Figures S.7-28 through S.7-32.

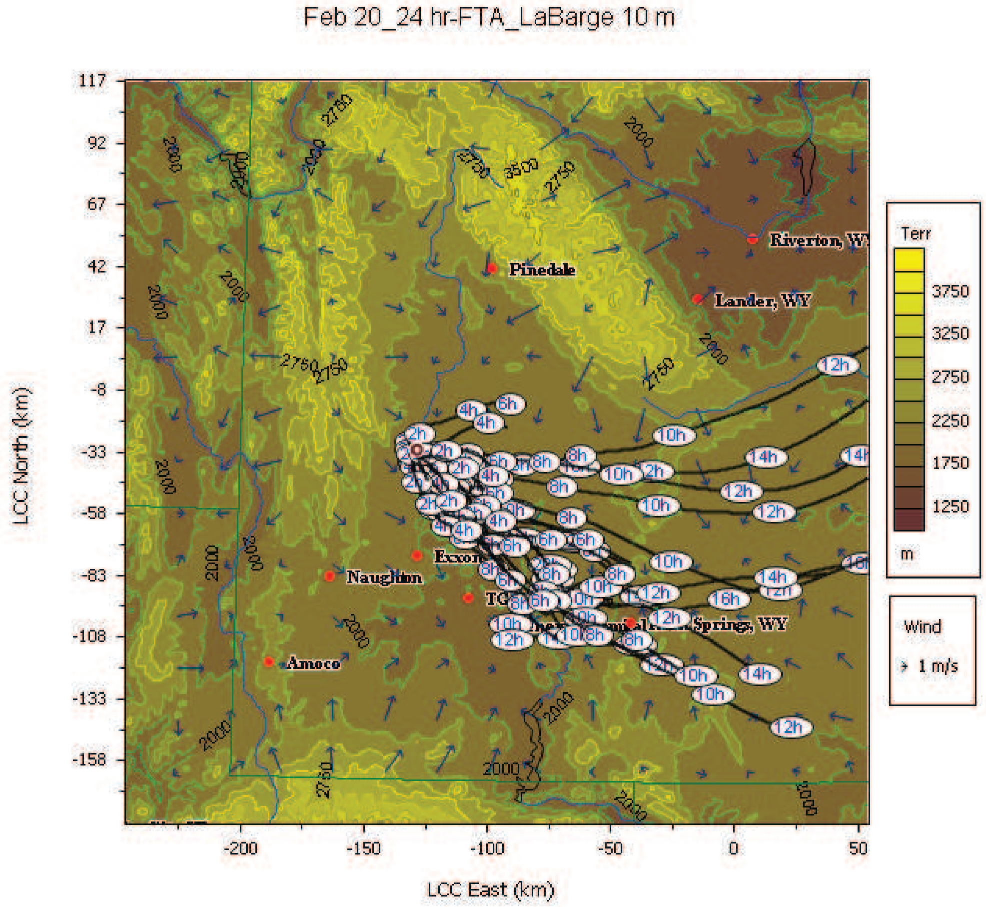


Figure S.7-28. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 20, 2008.

As shown in Figure S.7-28, on February 20, 2008, the trajectory analysis for the LaBarge area begins to exhibit a few possible trajectory paths into the area west of the Jonah oil and gas field, indicating some potential for upwind emissions transport at the Jonah monitor. Figures S.7-29 through S.7-32 show the prevailing northwest winds continue to limit southerly transport of emissions into the UGRB, along with the prevailing southwesterly winds along the Interstate-80 corridor, which are reflected in the trajectory analysis for the Moxa Arch area, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

It is important to note that as the trajectory start point is located further south, and out of the UGRB, the dominant northwest winds taper off, and the airflow at the south end of the UGRB mixes with the prevailing winds along the Interstate-80 corridor, which tend to dominate air parcel transport once the air parcel is out of the UGRB, south of the Wyoming Range terrain influence.

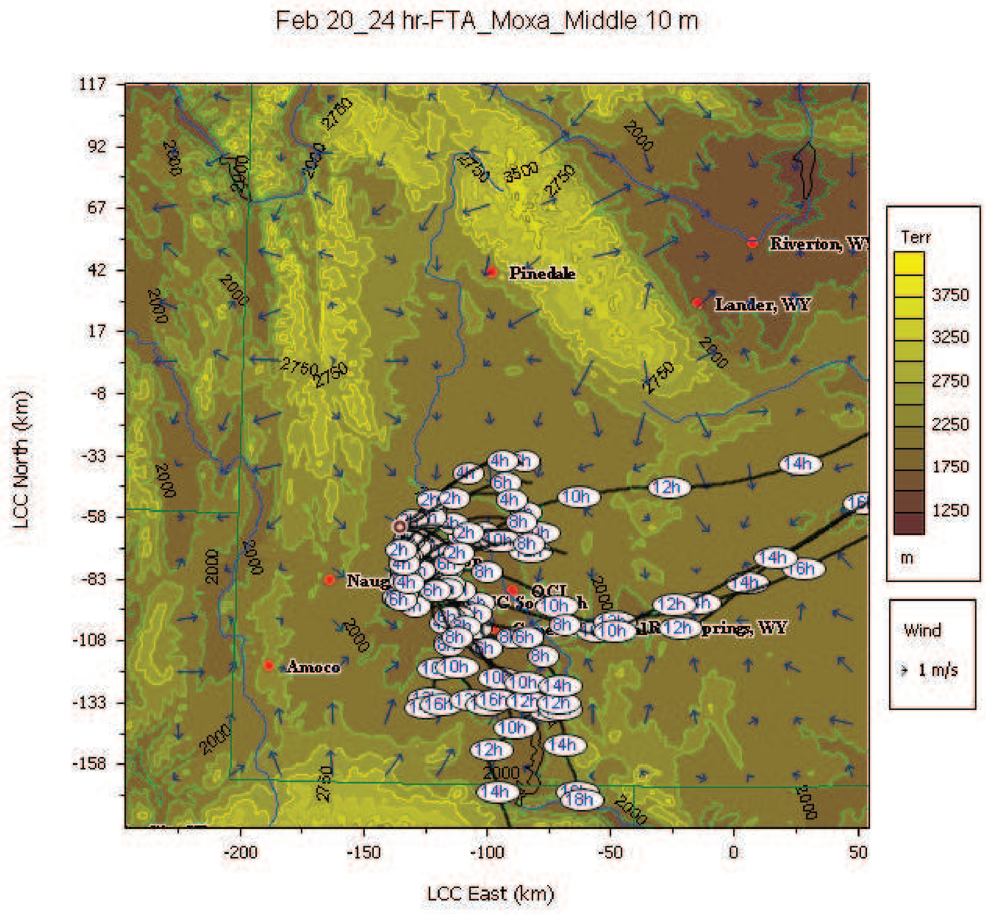


Figure S.7-29. 24-hour forward trajectory analysis in the Moxa Arch area on February 20, 2008.

The trajectory analysis in Figure S.7-29 shows all modeled trajectories from Moxa Arch not entering the proposed nonattainment area.

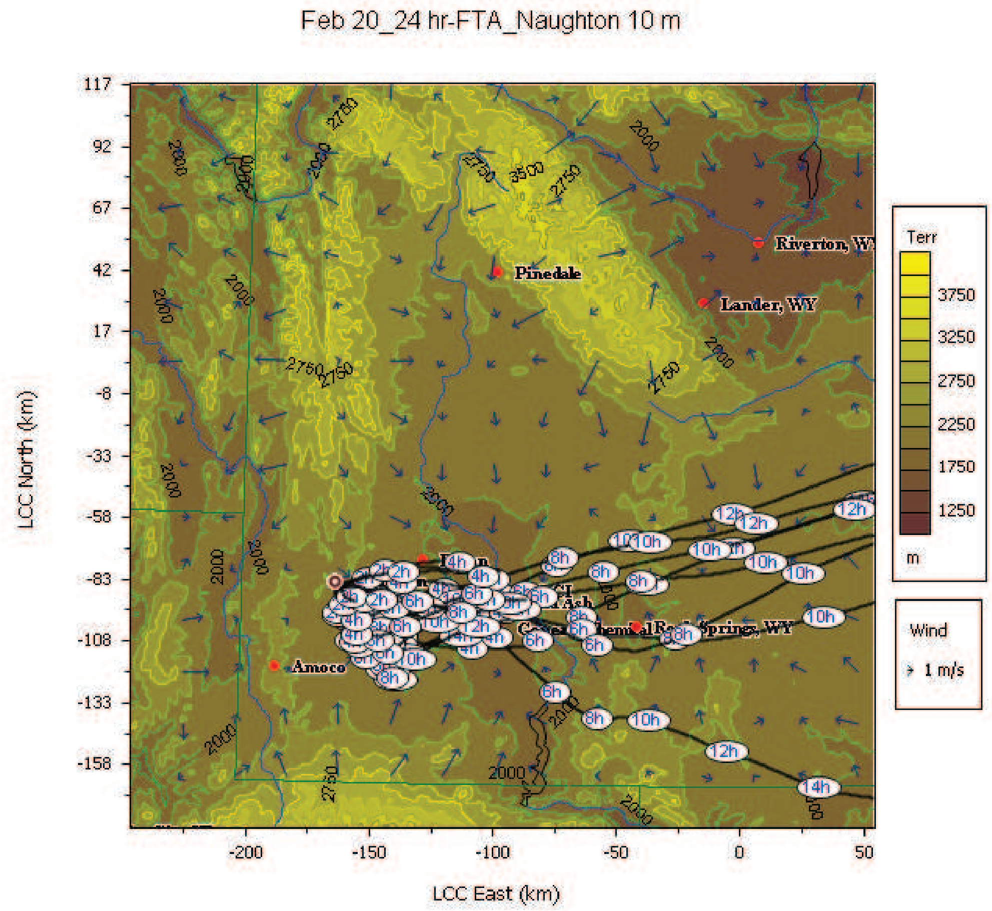


Figure S.7-30. 24-hour forward trajectory analysis at Naughton power plant on February 20, 2008.

The trajectory analysis in Figure S.7-30 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

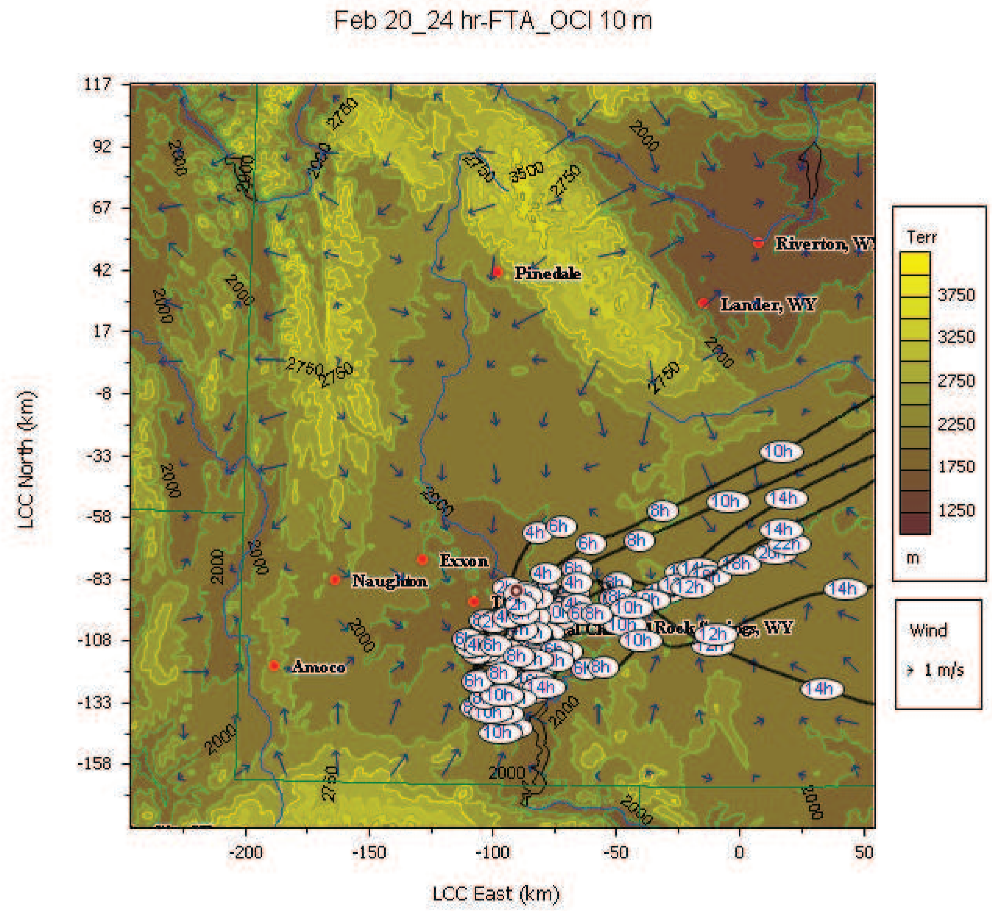


Figure S.7-31. 24-hour forward trajectory analysis at OCI Trona plant on February 20, 2008.

The trajectory analysis in Figure S.7-31 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

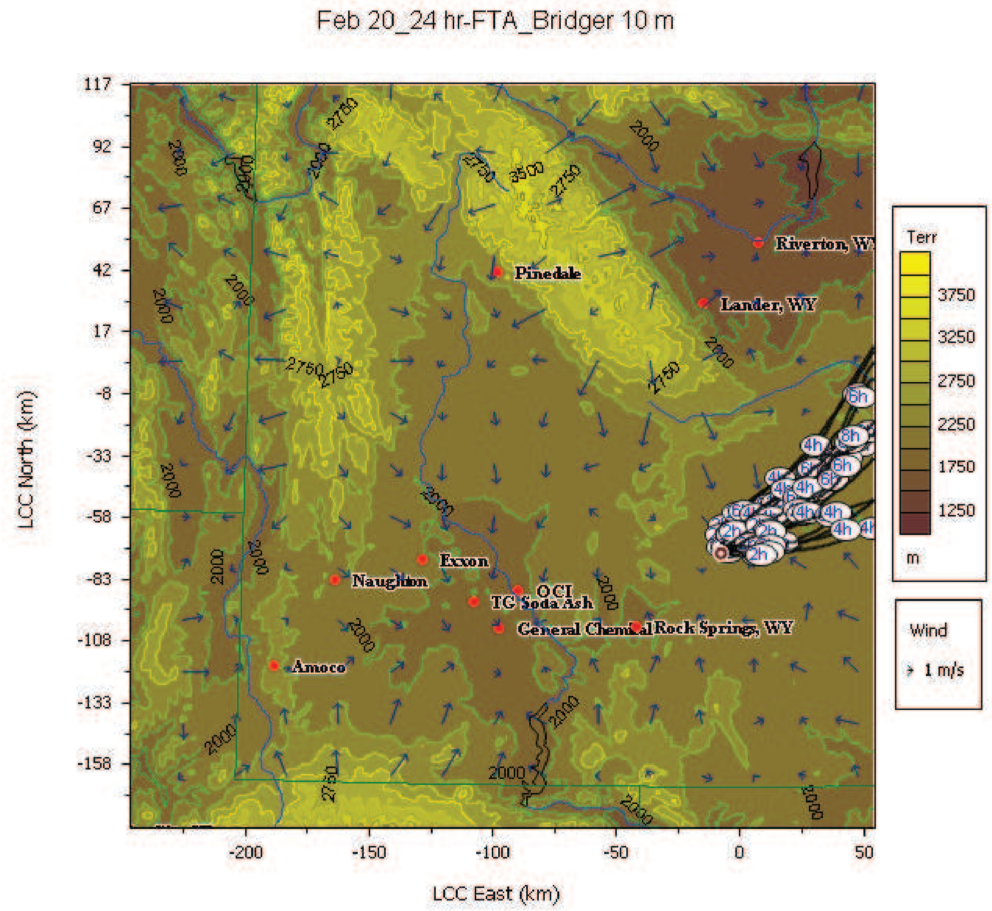


Figure S.7-32. 24-hour forward trajectory analysis at Bridger power plant on February 20, 2008.

The trajectory analysis in Figure S.7-32 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 21, 2008 are shown in Figures S.7-33 through S.7-37.

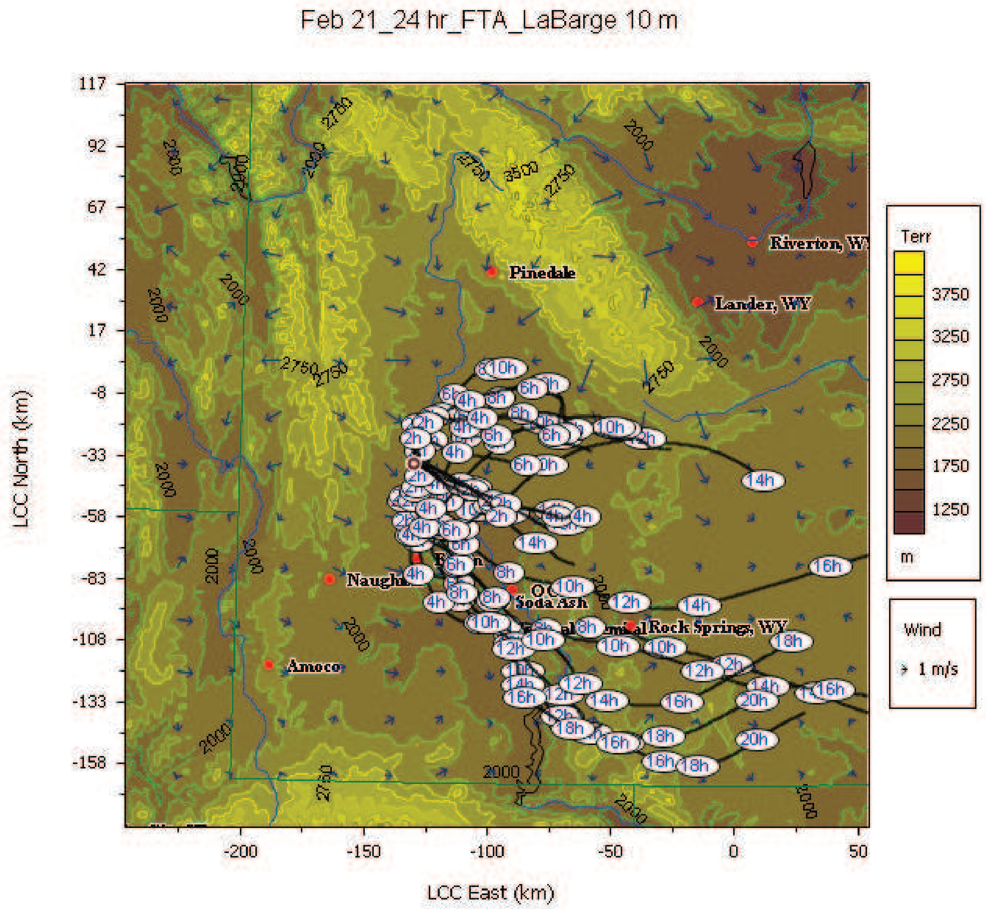


Figure S.7-33. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 21, 2008.

By the afternoon of February 21, 2008, the high pressure ridge had weakened, and had also flattened, and the central ridge axis was over or just east of southwestern Wyoming through the entire day; the resulting light wind stagnant situation also enabled the highest ozone production recorded at the Boulder monitoring site to date. These conditions were monitored during the first IOP, conducted February 18-21, 2008, in which a set of intensive meteorological and ambient measurements were collected when meteorological conditions similar to those associated with high ozone episodes during 2005 – 2006 had been forecast to occur during the 2008 field study.

The low level inversion was not quite as strong as on February 19, 2008, but it did stay intact through the entire daylight period, keeping ground level emissions trapped near the surface. With the very light and variable winds above the inversion, localized flow patterns near the ground level developed during the day allowing emissions to transport along those pathways.

As shown in Figure S.7-33, the trajectory analyses for the LaBarge area exhibit several possible air parcel paths to the northwest on February 21, 2008. Figure S.7-34 shows the trajectory analysis for the Moxa Arch area, which exhibits a few trajectories initially moving into the southernmost portion of the UGRB, but the strong northerly winds in the UGRB dominate the flow. This limits northward air parcel transport into the UGRB, and the vast majority of the trajectories continue to travel south out of the UGRB. The trajectory start point at Moxa Arch is approximately fourteen (14) miles south of the LaBarge trajectory start point, where the dominant northwest wind influence in the UGRB valley is tapering off, and mixes with prevailing westerly winds.

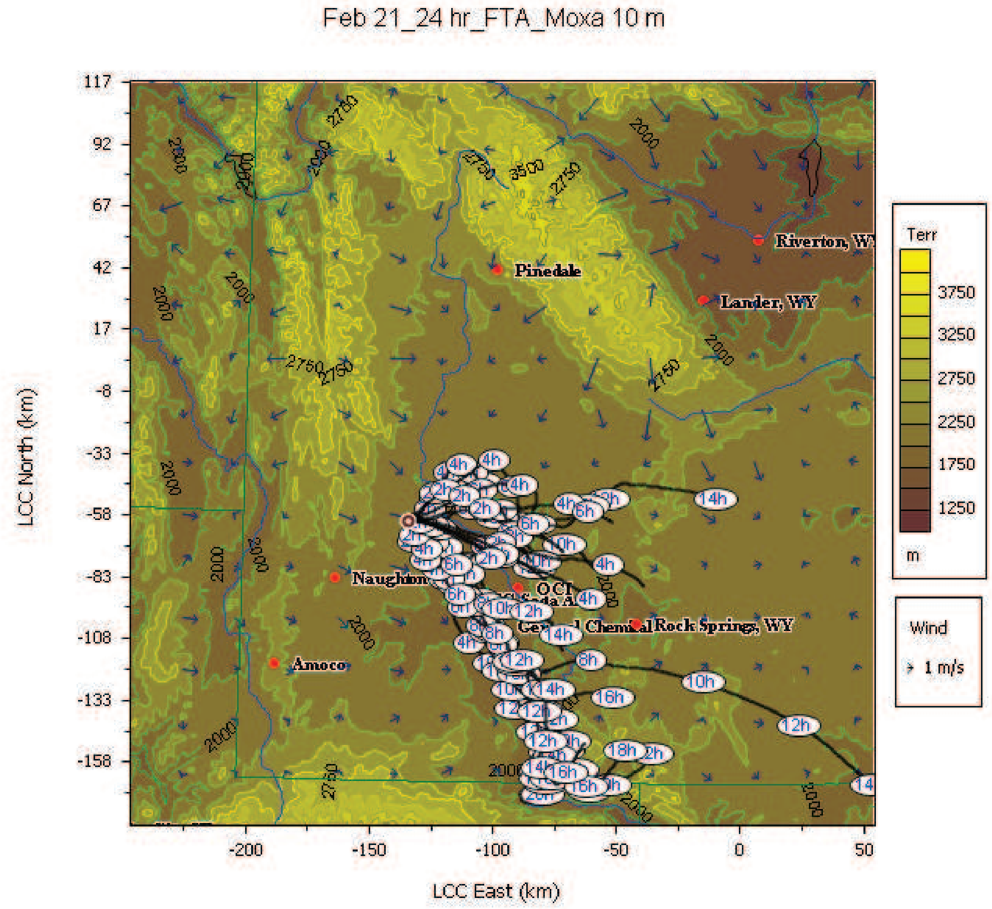


Figure S.7-34. 24-hour forward trajectory analysis in the Moxa Arch area on February 21, 2008.

Figure S.7-35 shows prevailing westerly winds at Naughton with air parcels moving eastward. The strong northwest winds in the UGRB and the terrain blocking effects of the Uinta Range to the south, collectively, influence the trajectory paths as they move from the Naughton power plant trajectory start point. The trajectory analysis in Figure S.7-35 shows all modeled trajectories from Naughton not entering the proposed nonattainment area

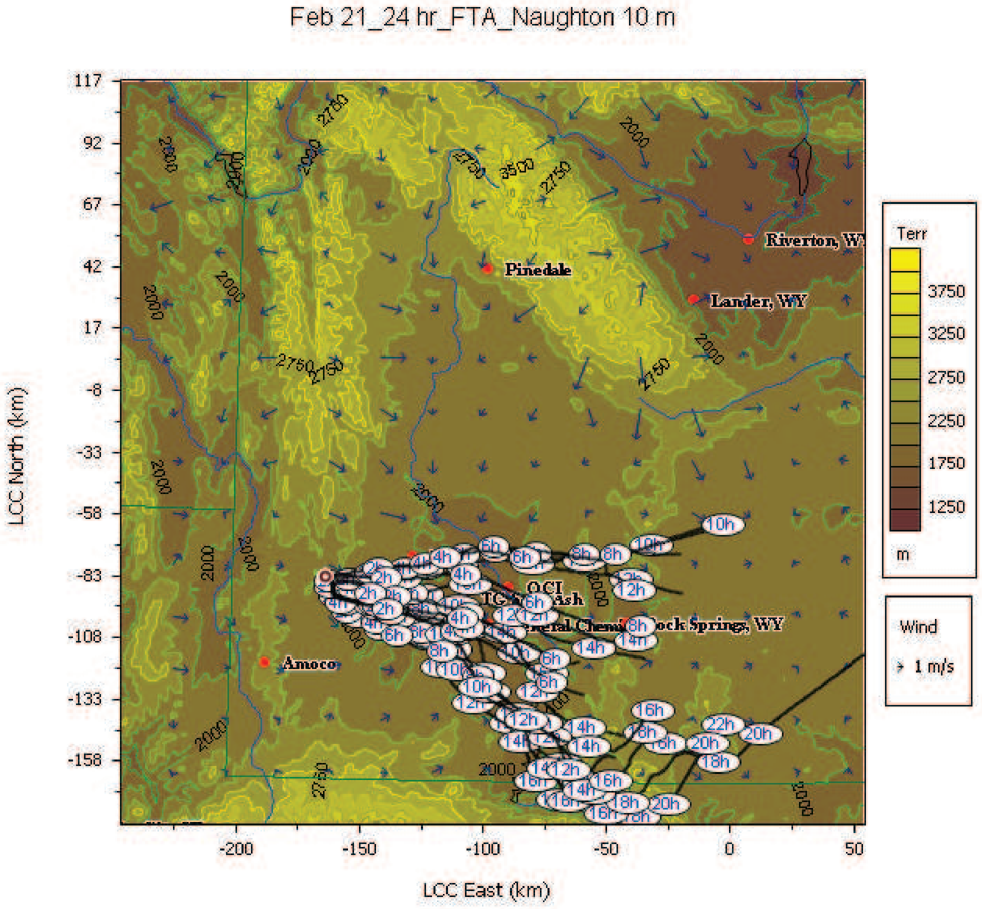


Figure S.7-35. 24-hour forward trajectory analysis at Naughton power plant on February 21, 2008.

Figures S.7-36 and S.7-37 show the prevailing westerly winds at the OCI Trona plant and the Bridger power plant, with the air parcels moving eastward and then northward. As noted with the forward trajectory paths from Naughton power plant, the strong northwest winds in the UGRB and the terrain blocking effects of the Uinta Range to the south continue to influence the trajectory paths as they move from the OCI and Bridger trajectory start points. The trajectory analysis in Figures S.7-36 and S.7-37 shows all modeled trajectories from OCI and Bridger not entering the proposed nonattainment area.

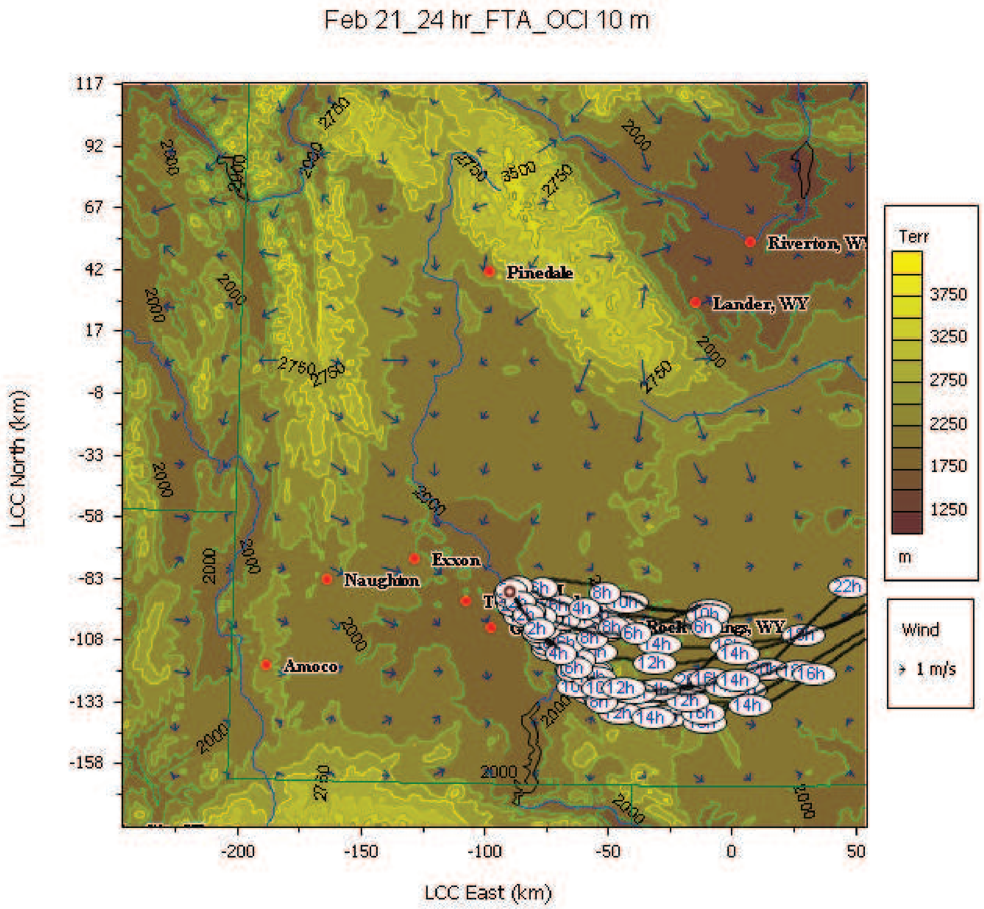

Feb 21_24 hr_FTA_OCI 10 m

Figure S.7-36. 24-hour forward trajectory analysis at OCI Trona plant on February 21, 2008.

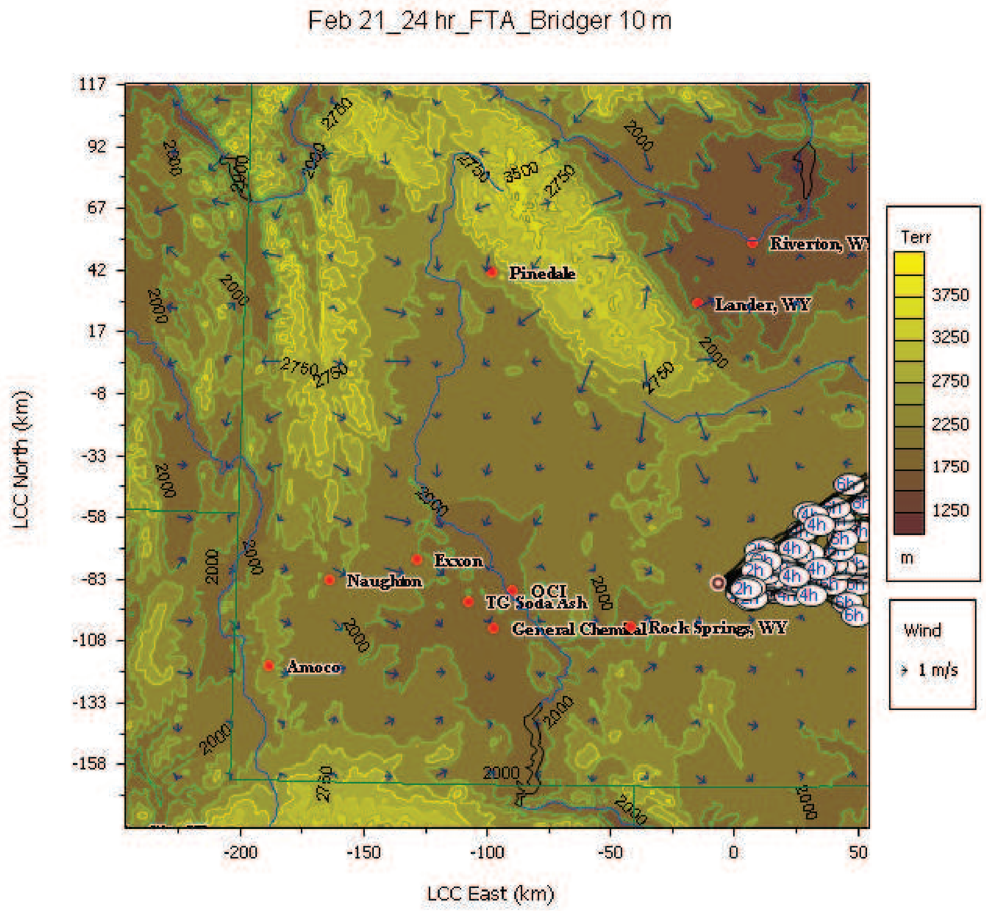


Figure S.7-37. 24-hour forward trajectory analysis at Bridger power plant on February 21, 2008.

As discussed previously, the localized meteorology within the UGRB during the ozone episodes influences air parcel movement within the UGRB, typically leading to shorter trajectory paths than if the trajectories were based on a start point located outside of the UGRB. CalDESK trajectory analyses that are initiated within the UGRB reflect the wind flow reversals and sustained low wind speeds; hence, shorter trajectory paths (and flow recirculation) are produced, which is consistent with the observed wind patterns.

During these wind reversals, the air flow changes direction. The winds are initially out of the northwest in the early morning, then out of the northeast, and then turn such that the winds flow out of the southeast later in the morning; the NW to SE wind flow reversal occurs approximately at 11:00 at the Boulder monitor on February 21, 2008.

CalDESK Forward Trajectory Analyses for February 22, 2008 are shown in Figures S.7-38 through S.7-42.

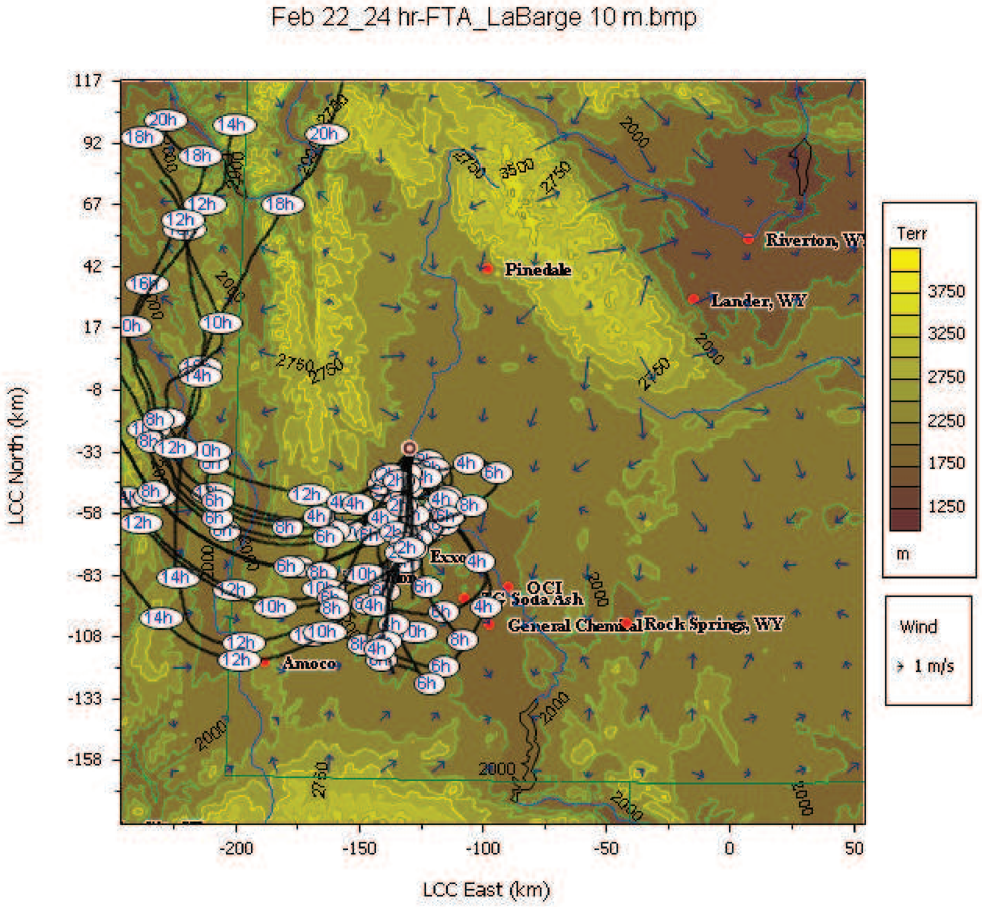


Figure S.7-38. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 22, 2008

The high pressure ridge continued to weaken during February 22, 2008, while a shortwave low pressure trough approached southwestern Wyoming from the northwest. Skies became mostly cloudy during the morning hours and light precipitation spread over the area later in the afternoon. However, the low level inversion stayed intact well into the afternoon, and ozone concentrations remained high during most of the day. No IOP operations were conducted this day because it was anticipated that the stable layer would be mixed-out by the trough by early morning and, therefore, trapped emission would be dispersed. Instead, the late arrival of the trough allowed one more day of high ozone concentrations.

As shown in Figure S.7-38, the trajectory analysis for the LaBarge area shows that most of the possible forward trajectory paths are now moving away from the UGRB during February 22nd. Figures S.7-38 through S.7-40 show air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There are 1-2 trajectory paths showing air parcel movement from the Moxa Arch and Naughton areas into the UGRB, however, the vast majority of the air parcel trajectories do not enter the UGRB, due to the significant terrain blocking and channeling effects of the terrain that make up the Wyoming Range and the Wasatch Range. Terrain blocking and channeling effects can also be seen in Figure S.7-42 in the forward trajectories originating from the OCI Trona plant.

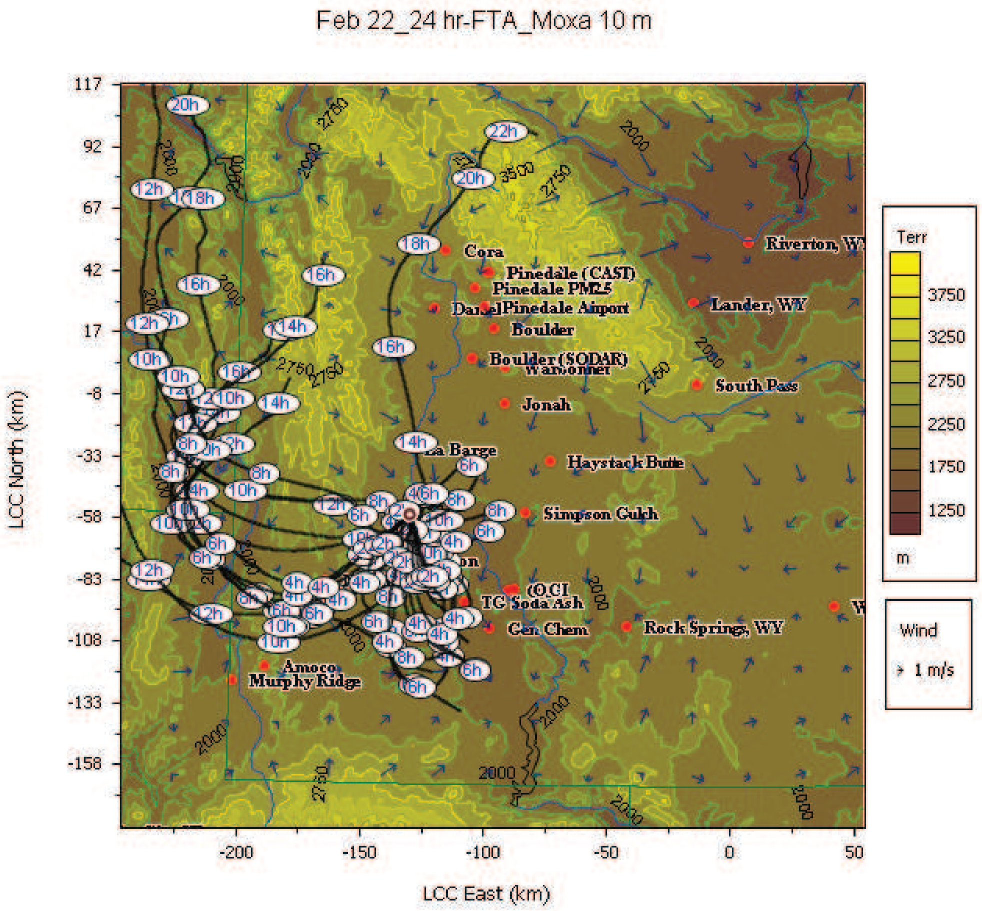


Figure S.7-39. 24-hour forward trajectory analysis in the Moxa Arch area on February 22, 2008.

Figure S.7-39 shows air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There are 1-2 trajectory paths showing air parcel movement from the Moxa Arch into the UGRB, however, the vast majority of the air parcel trajectories do not enter the UGRB, due to the significant terrain blocking and channeling effects of the terrain that make up the Wyoming Range and the Wasatch Range.

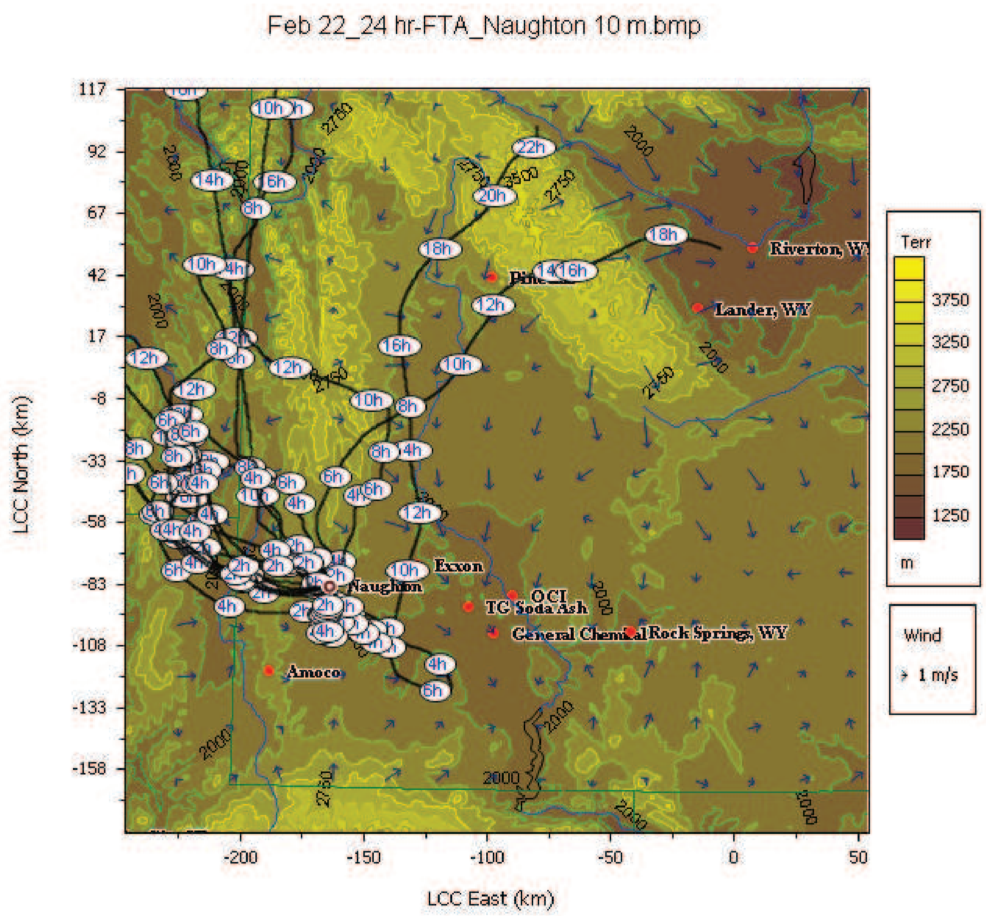


Figure S.7-40. 24-hour forward trajectory analysis at Naughton power plant on February 22, 2008.

There are two forward trajectory paths (2 am and 6 am) which show possible air parcel transport from the Naughton power plant into the UGRB. A 12-hour back trajectory analysis was performed at the Boulder monitor location (2 am – 2 pm) for February 22, 2008 to evaluate potential air parcel trajectories that could reach the Boulder monitor during this same time period (2 am and 6 am). The results of this back trajectory analysis are shown in Figure S.7-41.

Figure S.7-41 shows the calculated back trajectories of air parcels at the Boulder monitor tend to originate from within the UGRB, with very little air parcel movement occurring outside of the UGRB; the air parcels tend to stay within the UGRB during this 12 hour period (2 am – 2 pm) largely due to localized meteorological conditions in the UGRB. The back trajectory analysis in Figure S.7-41 shows a limited potential for sources outside the recommended nonattainment area to affect ozone measured at the Boulder monitor.

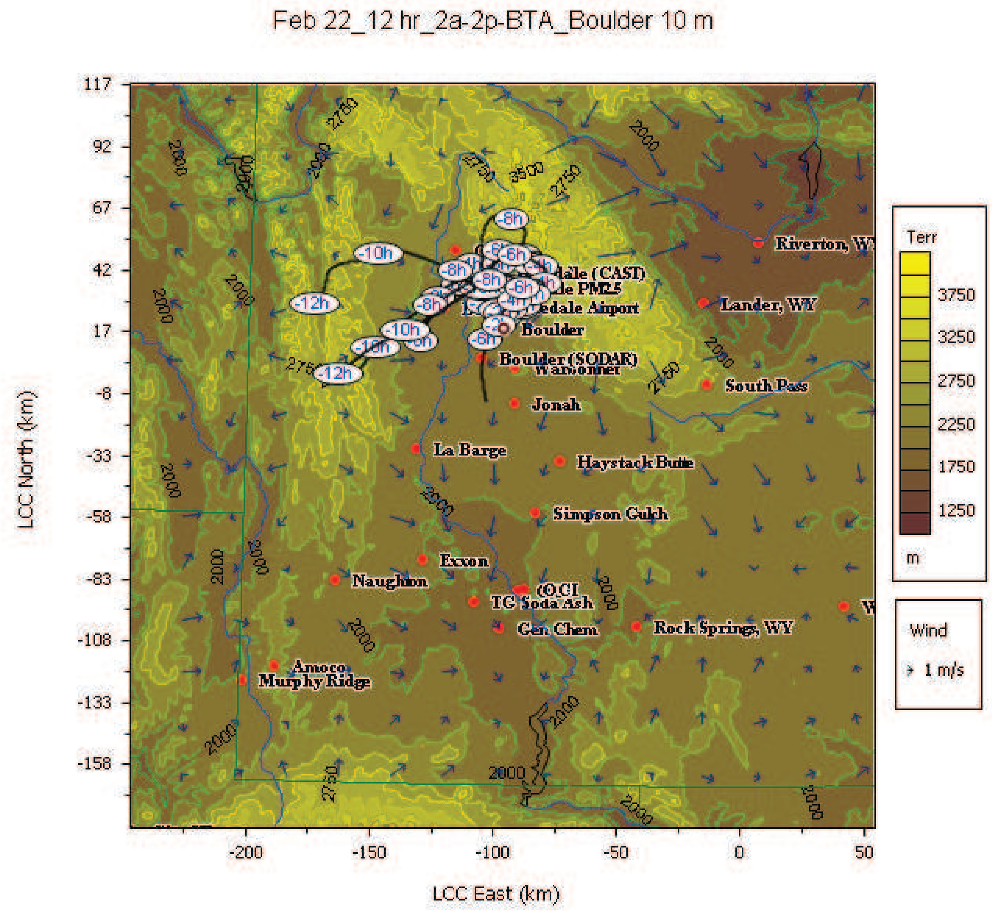


Figure S.7-41. 12-hour back trajectory analysis at Boulder monitor on February 22, 2008.

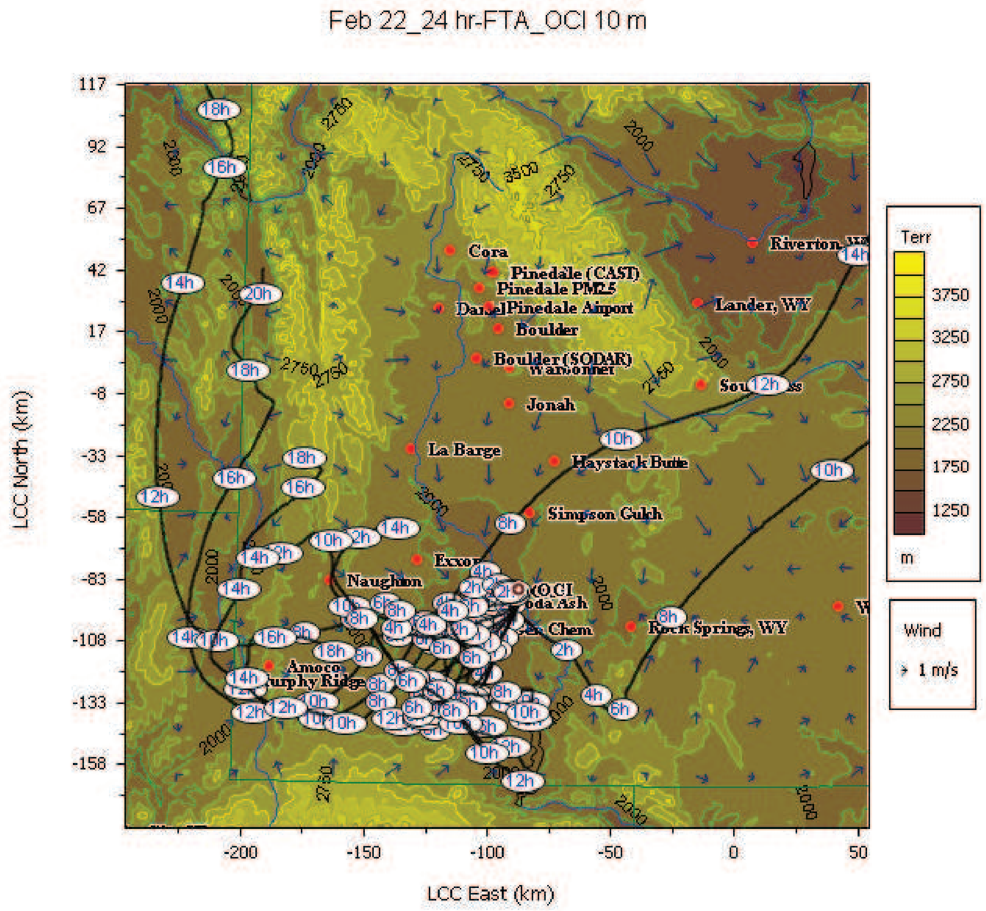


Figure S.7-42. 24-hour forward trajectory analysis at OCI Trona plant on February 22, 2008.

The predominant paths shown in the trajectory analysis shown in Figure S.7-42 trend to the south with northerly component to several of the modeled trajectories. Most of the possible forward trajectory paths are now moving away from the UGRB. Air parcels tend to be blocked and channeled westward and then northward around the Wyoming Range, with limited air parcel movement into the UGRB. There is one trajectory path showing air parcel movement from the OCI toward the UGRB. This trajectory generally parallels the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory path may lie within the proposed nonattainment area, the path does not indicate that sources at OCI cause or contribute to elevated ozone levels within the proposed nonattainment area.

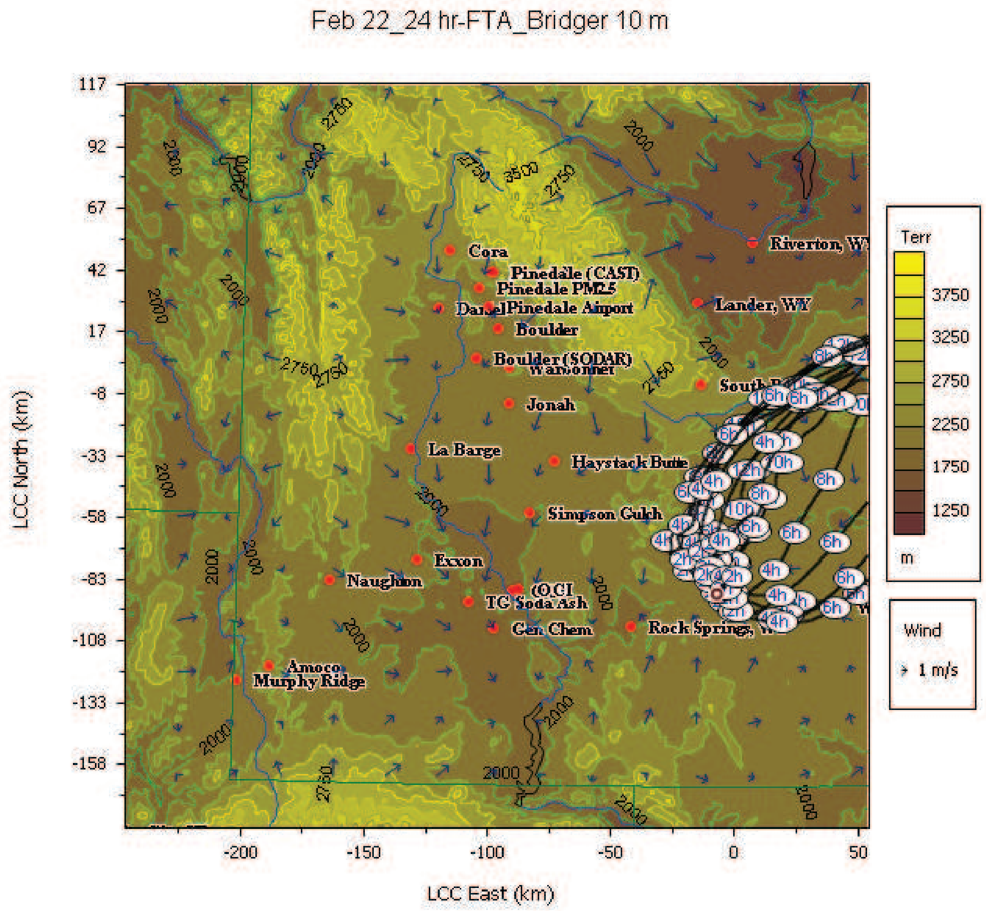


Figure S.7-43. 24-hour forward trajectory analysis at Bridger power plant on February 22, 2008.

The trajectory analysis in Figure S.7-43 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

CalDESK Forward Trajectory Analyses for February 23, 2008 are shown in Figures S.7-44 through S.7-48.

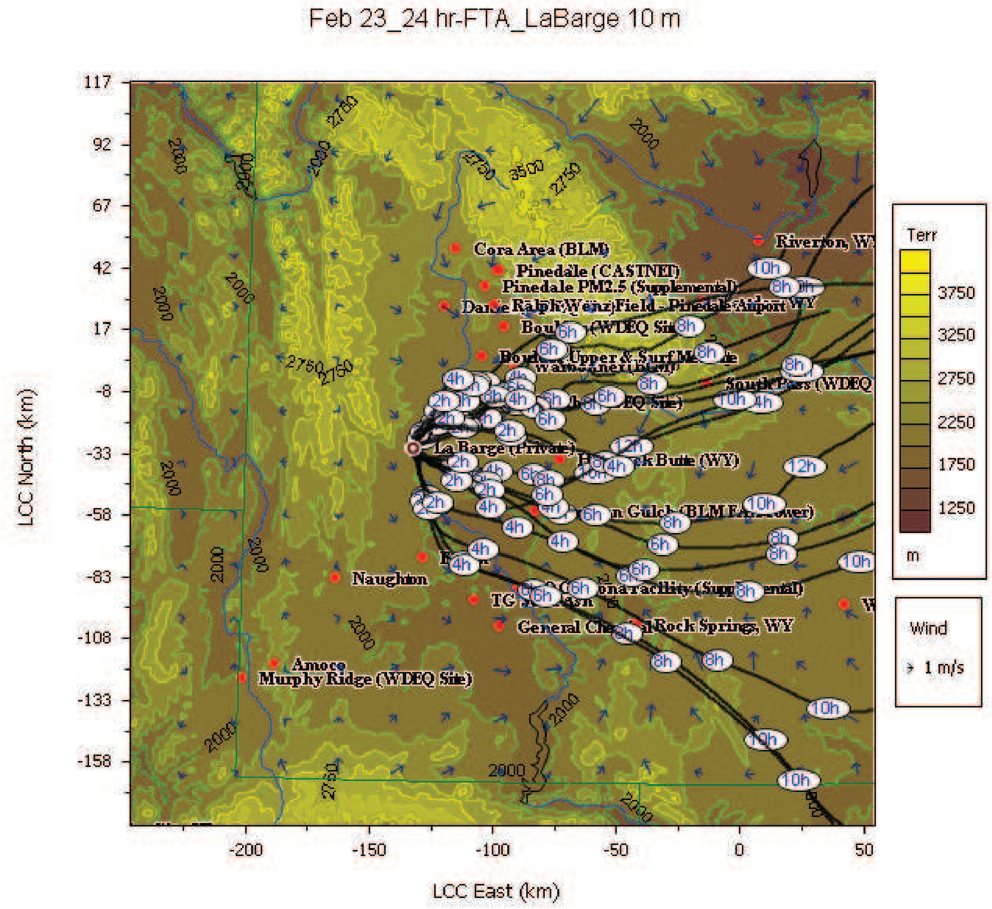


Figure S.7-44. 24-hour forward trajectory analysis at LaBarge, Wyoming on February 23, 2008.

Figure S.7-44 shows the trajectory analysis for the LaBarge area; there are a few forward trajectory paths going northeast during Feb 23, 2008, but most are channeled around the rising terrain at the south end of the UGRB and the Wind River Range. As shown in Figures S.7-45 through S.7-48, the prevailing west and southwest winds generally move air parcels eastward and then northward, as reflected in the trajectory analysis for the Moxa Arch area, the Naughton power plant, the OCI Trona processing facility, and the Bridger power plant.

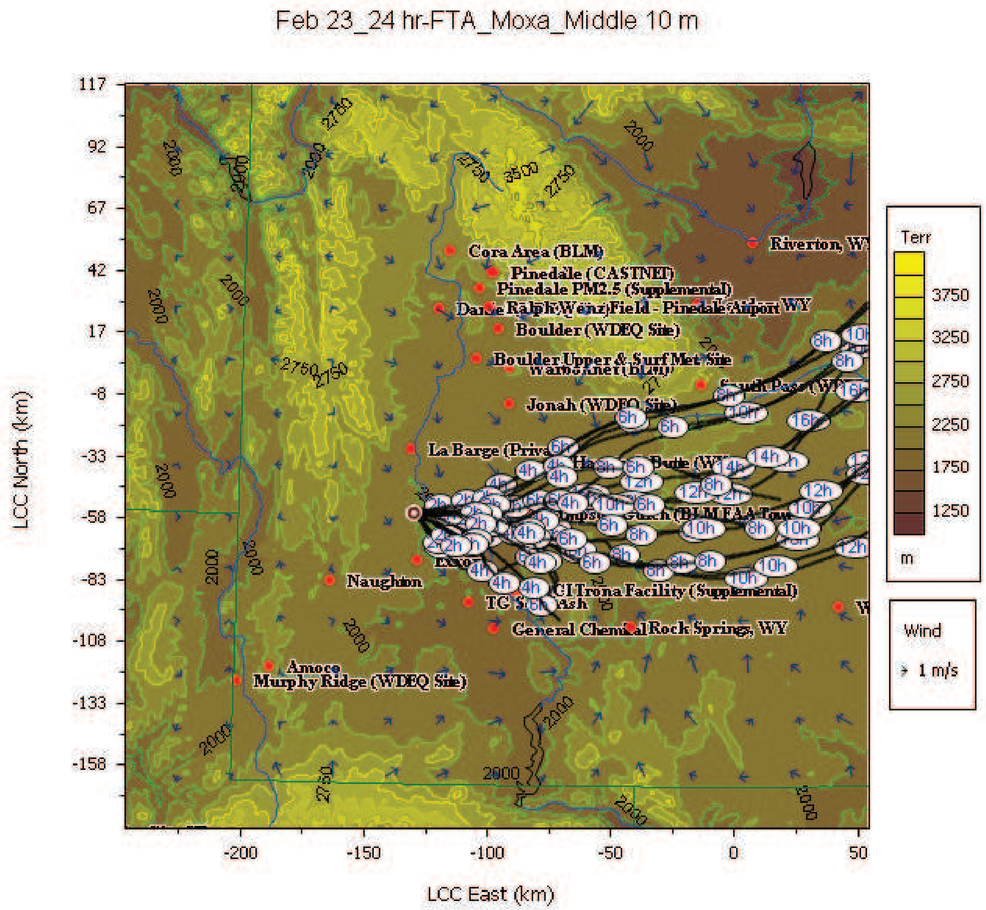


Figure S.7-45. 24-hour forward trajectory analysis in the Moxa Arch area on February 23, 2008.

The trajectory analysis shown in Figure S.7-45 places the initial air parcel release point in the northern part of the Moxa Arch field. The predominant paths shown trend to the east, and there is a slight northerly component to several of the modeled trajectories. These trajectories generally parallel the southern boundary of the proposed nonattainment area along Pacific Creek. While some of the trajectory paths lie within the proposed nonattainment area, none of the paths indicate that sources within the Moxa Arch cause or contribute to elevated ozone levels within the proposed nonattainment area.

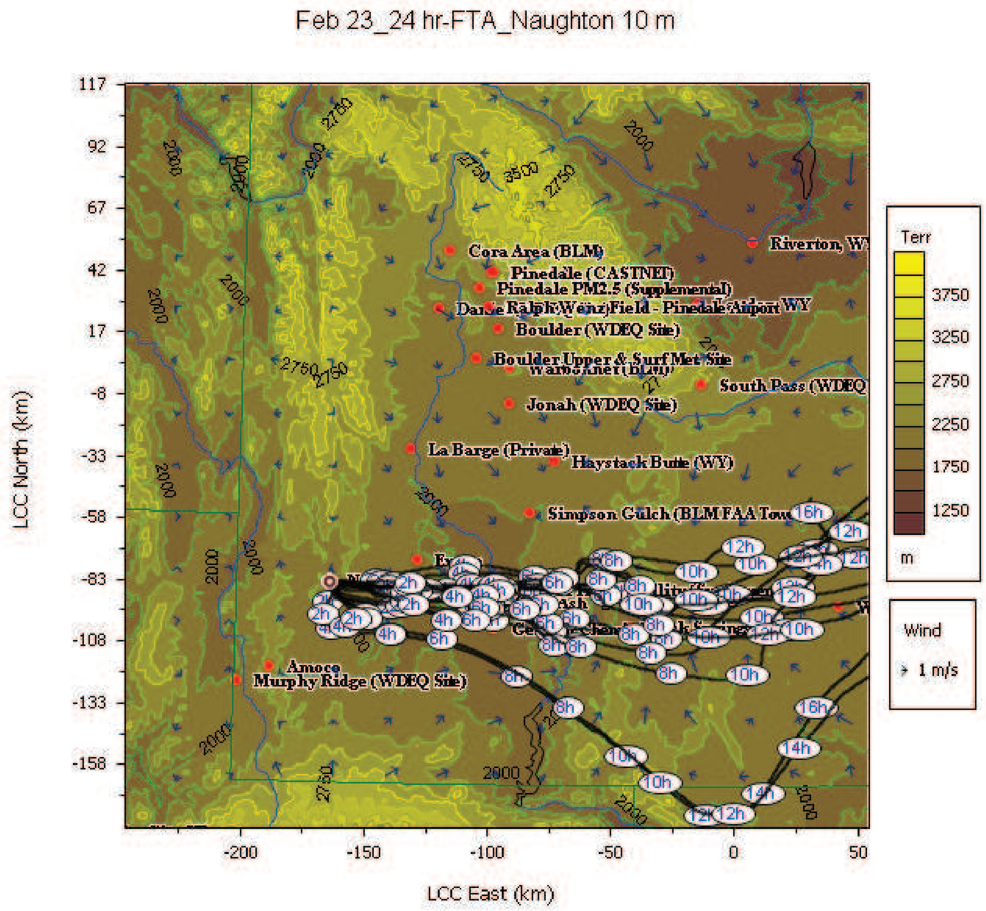


Figure S.7-46. 24-hour forward trajectory analysis at Naughton power plant on February 23, 2008.

The trajectory analysis in Figure S.7-46 shows all modeled trajectories from Naughton not entering the proposed nonattainment area.

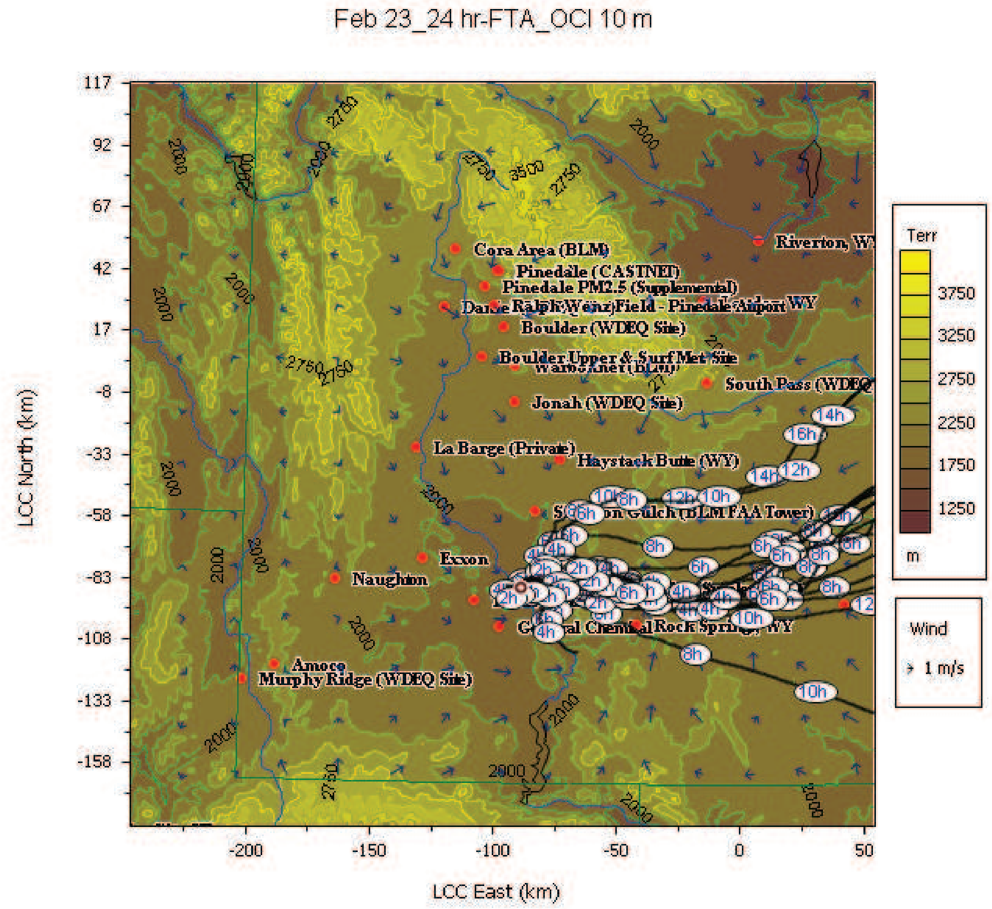


Figure S.7-47. **24-hour forward trajectory analysis at OCI Trona plant on February 23, 2008**.

The trajectory analysis in Figure S.7-47 shows all modeled trajectories from OCI not entering the proposed nonattainment area.

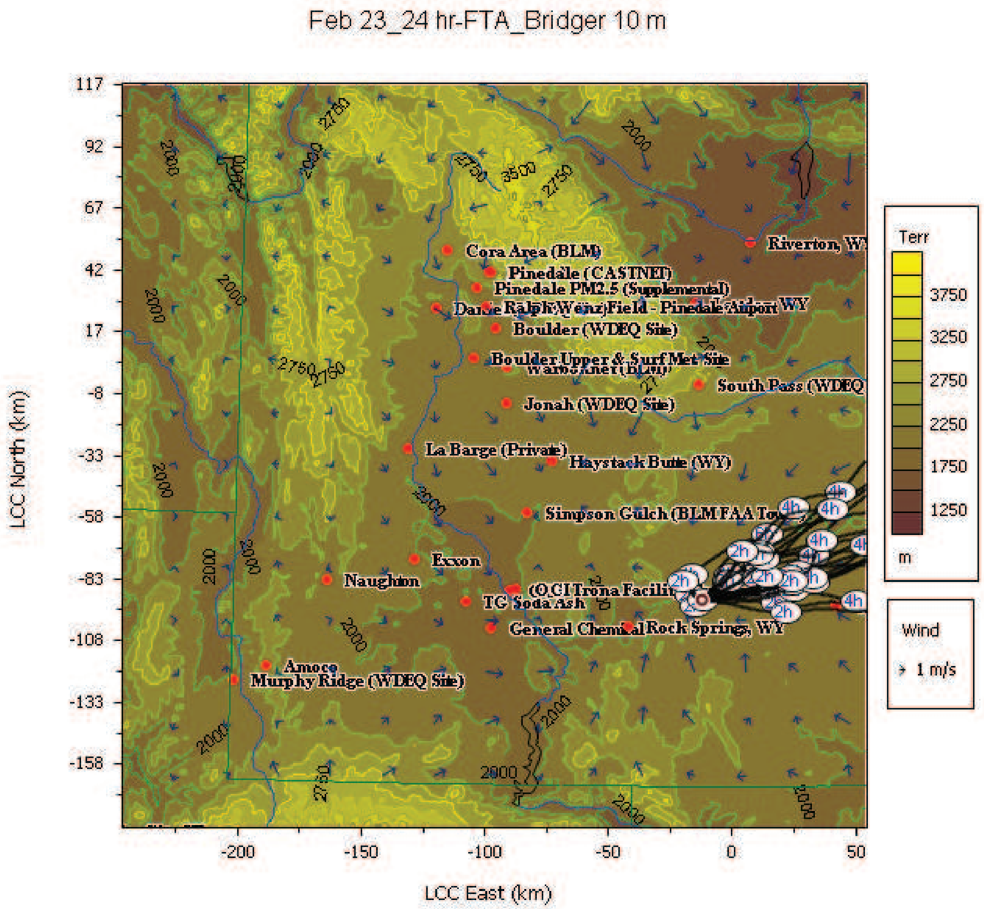


Figure S.7-48. 24-hour forward trajectory analysis at Bridger power plant on February 23, 2008.

The trajectory analysis in Figure S.7-48 shows all modeled trajectories from Bridger not entering the proposed nonattainment area.

Summary of Trajectory Analyses

The CalDESK trajectory analyses, based on a three dimensional wind field which incorporates the localized meteorological data collected during the 2008 field study have allowed AQD to evaluate air parcel movement as a means of evaluating precursor emissions and ozone transport into and out of the UGRB. These trajectories indicate that the southern boundary of the recommended nonattainment area defines an appropriate demarcation where emission sources within the nonattainment area may contribute ozone or ozone precursors to the Boulder monitor. Although the Fontenelle Creek, Little Sandy and Pacific drainages are not major topographic features, these drainage areas influence air movement into the UGRB from locations south of the recommended nonattainment area during the February 19-23, 2008 ozone episode and define a reasonable southern boundary for the nonattainment area. AQD has concluded that most, if not all, of the impact on the Boulder monitor just prior to and during these elevated ozone episodes is from emission sources located in the nonattainment area as described in this recommendation.

SECTION 8
JURISDICTIONAL BOUNDARIES

SYNOPSIS

The Sublette County jurisdictional boundary forms the northern and most of the western and eastern boundaries of the recommended nonattainment area. The remainder of the boundary is not jurisdictional but is based on topographical and meteorological considerations.

There is no existing local authority that transcends county boundaries, so the recommended nonattainment area has no single local administrative authority.

ANALYSIS

The Boulder monitor is located in Sublette County. Sublette County is governed by a three-person Commission. There are three incorporated towns in Sublette County: Pinedale, Big Piney and Marbleton. Approximately 80% of the land in Sublette County is owned by the government: BLM-40%; USFS-36%; State of Wyoming-4%. Federal and state land ownership in the surrounding counties follows a similar pattern.

The evaluation of the nonattainment area began with the Sublette County jurisdictional area as the presumptive boundary. This is consistent with EPA guidance in the December 4, 2008 memorandum which states: "Where a violating monitor is not located in a CBSA" (Core Based Statistical Area) "or CSA," (Combined Statistical Area) "we recommend that the boundary of the county containing the monitor serve as the presumptive boundary for the nonattainment area." The Boulder monitor is not in a CBSA or CSA.

The recommended nonattainment area includes all of Sublette County; the portion of Lincoln County northeast of the waterways of Aspen, Fontenelle, and Roney Creeks and northeast of Fontenelle Reservior and the Green River; and the portion of Sweetwater County northwest of the waterways of the Green River, the Big Sandy River, Little Sandy Creek, Pacific Creek, and Whitehorse Creek (see the detailed description in the introduction). This area includes the town of LaBarge in Lincoln County. The southern boundary of the recommended nonattainment area is defined based on topographical and meteorological considerations rather than jurisdictional boundaries. The Sublette County borders to the north, east, and west follow topographic features (mountain ranges) and are appropriate boundaries for the nonattainment area.

The six counties in Southwest Wyoming which were also included in the analysis are: Teton, Lincoln, Uinta, Sweetwater, and Fremont. Two Indian Tribal Nations are also located in the area, the Northern Arapahoe and Eastern Shoshone, at the Wind River Reservation in Fremont County. The reservation and the counties are shown in Figure S.1-1.

The recommended nonattainment area boundary does not fall under single authority, other than the State of Wyoming.

SECTION 9
LEVEL OF CONTROL OF EMISSION SOURCES

SYNOPSIS

Wyoming's NSR Program ensures that Best Available Control Technology (BACT) is utilized to reduce and eliminate air pollution emissions. Wyoming is fairly unique in that BACT is applied statewide to all new sources, both major sources and minor sources. Since 1995 all oil and gas production units that were constructed on or after May of 1974 require permits and BACT is utilized. In two of the gas fields in the proposed nonattainment area, more restrictive emission control requirements are already in effect. Wyoming has been focused on controlling emissions from oil and gas sources and has one of the most innovative and effective control programs in the nation.

While offset programs are traditionally limited to major source applications, the AQD issued an interim policy in August 2008 requiring offsets of ozone precursor emissions whenever a permit is issued for a new or modified source in Sublette County, regardless of major source applicability. This policy results in a net decrease in emissions of ozone precursors with every permit that is issued. This policy took effect after the ozone exceedances were recorded in the winter of 2008.

Data is not available for 2009, so it is too early to say with certainty whether this policy has contributed to reduced ozone concentrations at the Boulder monitor.

ANALYSIS

New Source Review Program

Wyoming's New Source Review (NSR) Program is a statewide permit program for the construction of new sources and modification of existing sources as established by Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 2, Permit requirements for construction, modification and operation and Chapter 6, Section 4, Prevention of significant deterioration. The primary purpose of the NSR Program is to assure compliance with ambient standards set to protect public health, assure that Best Available Control Technology is utilized to reduce and eliminate air pollution emissions, and to prevent deterioration of clean air areas. Any amount of air contaminant emissions from a facility subjects it to Wyoming's NSR Program.

Best Available Control Technology

Due to a desire to maintain and improve Wyoming's air quality, the Best Available Control Technology process is applied statewide to new sources, both major sources and minor sources, under the Wyoming NSR Program's permitting process. The BACT process is most appropriately defined as the elimination of pollutants from being emitted into the air whenever technically and economically feasible to do so. While the Air Quality Division takes the State and federally-required BACT review in the Prevention of Significant Deterioration (PSD) permitting actions seriously, AQD takes the State-required BACT review in minor source permitting actions equally as seriously, as the bulk of AQD's permit applications are for minor sources.

Control of Oil and Gas Production Sources

Within the recommended nonattainment area, the bulk of the NSR Program activity is due to oil and gas production and is permitted per the *Oil and Gas Production Facilities Chapter 6, Section 2, Permitting Guidance* discussed below. The remainder of the activity is attributed to facility types such as the compressor stations, asphalt plants and crushing and screening operations, which are permitted per Chapter 6, Section 2 and Chapter 6, Section 4 as described above.

In October 1995, AQD initiated a program to ensure that all oil and gas production units in southwest Wyoming, as well as the entire state, that were constructed since May of 1974 (the effective date of Wyoming's NSR Permit Program) were permitted and that BACT is utilized to control or eliminate emissions from both major and minor sources. To guide oil and gas producers through the NSR permitting process, AQD developed an oil and gas industry guidance document (Guidance) that was released in June of 1997. The Guidance has been revised several times since it was originally released in June of 1997. The most recent revision took effect in August of 2007 and includes requirements that apply statewide as well as specifically to the Jonah and Pinedale Anticline Development (JPAD) Area. The emphasis of the Guidance relies on a "Presumptive BACT" process, which results in more emissions being controlled earlier in the life of the production site. This is accomplished by allowing start up or modification of the production site to occur prior to obtaining a construction permit, provided the operators of such facilities meet certain emission control requirements, including timely installation of controls, which have been established through the Presumptive BACT process. Within the JPAD Area, emission control requirements are more restrictive and become effective upon start up or modification of the production site.

Under the WAQSR, applicants for permits are required to demonstrate to the Administrator of the Air Quality Division, that "[t]he proposed facility will not prevent the attainment or maintenance of any ambient air quality standard." [WAQSR Chapter 6, Section 2(c)(ii)] To allow applications for new or modified emission sources of VOC and/or NOx to be processed while the Division and industry initiatives are taken to reduce the overall emission levels for VOC and/or NOx in Sublette County, AQD adopted the *Interim Policy on Demonstration of Compliance with WAQSR Chapter 6, Section 2(c)(ii) for Sources in Sublette County* on July 21, 2008. The Interim Policy describes options that AQD will consider as an adequate WAQSR Chapter 6, Section 2(c)(ii) demonstration for permit applications (i.e., new as well as applications currently under AQD analysis) for new or modified emission sources in Sublette County.

Options for the Chapter 6, Section 2(c)(ii) demonstration include:

a. Ambient ozone modeling for any application requesting increases in VOCs and/or NOx emissions.
b. Emission reductions for VOCs and/or NOx emissions.

c. Applicants may propose alternate innovative demonstrations to the AQD.

To date, most applicants have chosen to offset VOC and/or NOx emissions and permit conditions have been established to make the commitments to control emissions federally enforceable.

During the implementation of the Interim Policy, other long-term approaches (e.g., development of a regional ozone model and implementation of additional control strategies) to deal with unacceptable ozone levels in the recommended nonattainment area, will continue to be pursued by AQD.

Statewide and Industry-wide Control of Volatile Organic Compounds (VOC)

WAQSR Chapter 13 establishes minimum requirements for motor vehicle emission control.

The following federal rules which are incorporated by reference in WAQSR Chapter 5 by reference contain performance or emission standards for VOCs that may apply to sources within the recommended nonattainment area and in adjacent areas:

40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR Part 60, Subpart Db - Standards of Performance for Industrial- Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart I - Standards of Performance for Hot Mix Asphalt Facilities

40 CFR Part 60, Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

40 CFR Part 60, Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 60, Subpart WWW - Standards of Performance for Municipal Solid Waste Landfills

40 CFR Part 63, Subpart F - National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry

40 CFR Part 63, Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

40 CFR Part 63, Subpart M - National Perchloroethylene Air Emission Standards for Dry Cleaning Facilities

40 CFR Part 63, Subpart R - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

40 CFR Part 63, Subpart T - National Emission Standards for Halogenated Solvent Cleaning

40 CFR Part 63, Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

40 CFR Part 63, Subpart OO - National Emission Standards for Tanks - Level 1

40 CFR Part 63, Subpart PP - National Emission Standards for Containers

40 CFR Part 63, Subpart QQ - National Emission Standards for Surface Impoundments

40 CFR Part 63, Subpart RR - National Emission Standards for Individual Drain Systems

40 CFR Part 63, Subpart SS - National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process

40 CFR Part 63, Subpart TT - National Emission Standards for Equipment Leaks - Control Level 1

40 CFR Part 63, Subpart UU - National Emission Standards for Equipment Leaks - Control Level 2 Standards

40 CFR Part 63, Subpart VV - National Emission Standards for Oil-Water Separators and Organic-Water Separators

40 CFR Part 63, Subpart WW - National Emission Standards for Storage Vessels (Tanks) - Control Level 2

40 CFR Part 63, Subpart HHH - National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

40 CFR Part 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

40 CFR Part 63, Subpart VVV - National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works

40 CFR Part 63, Subpart AAAA - National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills

40 CFR Part 63, Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

40 CFR Part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR Part 63, Subpart CCCCC - National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks

40 CFR Part 63, Subpart GGGGG - National Emission Standards for Hazardous Air Pollutants: Site Remediation

40 CFR Part 63, Subpart HHHHH - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Coating Manufacturing

40 CFR Part 63, Subpart LLLLL - National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing

Statewide and Industry-wide Nitrogen Oxides (NOx)

WAQSR Chapter 2 establishes ambient air quality standards for those areas under WDEQ's jurisdiction. The standard for nitrogen oxides (NOx) is 100 ug/m^3 as an annual arithmetic mean. All facilities that are required to obtain a New Source Review (NSR) permit or a Title V permit under WAQSR Chapter 6 must demonstrate compliance with the State's ambient air quality standard before a permit can be issued.

WAQSR Chapter 3, Section 3 specifies nitrogen dioxide emission standards. Permitting rules require sources to meet NOx emission standards.

The following federal rules, which are incorporated by reference into Chapter 5, Sections 2 and 3 contain performance or emission standards for NOx that may apply to sources in the proposed nonattainment area and in the surrounding counties:

40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

40 CFR Part 60, Subpart Db - Standards of performance for Industrial- Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

The following federal New Source Performance Standards have not yet been adopted into State rules, but are scheduled for adoption. The federal standards will still apply.

NSPS Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines)

Contingency Plans

AQD requested that producers in parts of the proposed nonattainment area prepare emission reduction plans to be implemented when an ozone advisory is issued. The BLM adopted a contingency plan requirement in the Pinedale Anticline ROD. Producers, which cumulatively account for greater than 99% of production in the Pinedale Anticline, submitted contingency plans to the AQD. During the first quarter of 2009, the AQD issued ozone advisories on February 4th and 5th. The contingency plans were implemented and no 8-hour ozone values above 0.075 ppm were recorded at FRM monitors for those days.

CONCLUSIONS

The information presented in the preceding nine-factor analysis provides documentation and compelling evidence supporting a finding that the UGRB, as shown on the map in the Introduction, should be designated as nonattainment for the 2008 ozone NAAQS. It is important to note that only areas over which Wyoming has direct air quality jurisdiction are included in this nonattainment finding and recommendation. The Northern Arapahoe and Eastern Shoshone Indian Tribes are distinct nations or entities and consequently such Tribal lands (the Wind River Reservation) are specifically excluded from this designation recommendation.

The Wyoming AQD bases this recommendation on a careful review of the circumstances surrounding the incidence of elevated ozone events. Elevated ozone in the UGRB is associated with distinct meteorological conditions. These conditions have occurred in February and March in some (but not all) of the years since monitoring stations began operation in the UGRB in 2005. Our determination of an appropriate nonattainment area boundary is focused on an evaluation of EPA’s recommended nine factors, applied to the first quarter of the year, during which winter ozone episodes occur. This timing does not change how the factors are reviewed, except for emissions inventory and meteorology. It is important to evaluate inventory and meteorology during the first quarter of the year in order to focus on the very specific conditions that lead to high ozone.

The most compelling reasons for the boundary recommendation are based on the meteorological conditions in place during and just prior to elevated ozone events. Elevated ozone episodes occurred in 2005, 2006 and 2008; they were associated with very light low-level winds, sunshine, and snow cover, in conjunction with a strong low-level surface-based temperature or “capping” inversion. The longest such event, which also resulted in the highest measured ozone of 122 ppb as an 8-hour average at the Boulder station, has been reviewed in detail and summarized in Section 7 of this document. Section 7 demonstrates that sources outside the recommended nonattainment area would not have a significant impact on the Boulder monitor due to the presence of the inversion and very low winds, which significantly limit emissions and ozone transport from sources located outside of the UGRB. Using detailed meteorological data collected during the February 19-23, 2008 ozone episode, a 1 kilometer high resolution (spatial and temporal) 3-dimensional gridded wind field was developed and used in trajectory analyses. The trajectory analyses show that air parcels originating at sources located south of the recommended nonattainment area – including power plants, Trona facilities, and the Moxa Arch gas field – are generally transported eastward and do not enter the UGRB just prior to and during the February 19-23, 2008 ozone episode. The meteorological conditions present during this multi-day ozone episode are representative of the meteorological conditions that were present during previous wintertime elevated ozone events that occurred in 2005 and 2006. From the trajectory analyses, it is concluded that emission sources located outside of the recommended nonattainment boundary could only have a very limited impact on the Boulder monitor, as the mountains to the west, north and east, along with the observed low wind speeds, would greatly limit the possibility of emissions transport.

The nine-factor analysis also concluded the following:

1. Ozone monitoring outside of the UGRB throughout Wyoming shows attainment of the 2008 NAAQS.
2. Emissions inventories of ozone precursors indicate that sources within the UGRB emit significant levels of precursors. Emissions from outside of the UGRB (while comparable to [for VOCs] or greater than [for NOx] emissions from within the UGRB) do not significantly influence the formation of ozone during and immediately preceding episodes of elevated ozone.
3. Population densities in Sublette and surrounding counties are very low and are not expected to be an important factor in ozone formation. This is also true of traffic and commuting patterns, which would be expected to be more important in urban areas rather than the rural communities and open spaces of southwest Wyoming.
4. The pace of growth in the oil and gas industry is significantly higher in the UGRB than in surrounding areas, which would correspond to a more rapid increase in emissions within the recommended nonattainment area in recent years.
5. Significant terrain features influence the meteorology throughout southwest Wyoming. Under a stagnating high pressure system, strong temperature inversions and low mixing heights tend to produce limited atmospheric mixing and precursor emissions can build up to high concentrations.

The elevated ozone episodes within the UGRB represent a unique situation which is quite different from other ozone nonattainment areas. The UGRB is rural with a very low population density; the only significant industry present is oil and gas. The significant terrain features surrounding the UGRB and the very low wind speeds associated with elevated ozone episodes may limit the ability of trajectory models, such as the HYSPLIT model, to accurately represent movement of air parcels within, into and out of the UGRB during these winter ozone events.

Due to the importance of meteorology to the formation of elevated ozone at the Boulder monitor – that is, ozone at levels that result in an exceedance of the NAAQS occurs during periods characterized by low mixing heights, temperature inversions and sustained low wind speeds – any emission reduction applied to sources outside of the UGRB will not result in any meaningful change in ozone levels at the Boulder monitor during these episodic conditions.

The information presented in this technical support document provides a strong weight-of-evidence basis for the recommended nonattainment boundary.

Appendix S.1.
Final Report 2008 Upper Green River Winter Ozone Study

http://deq.state.wy.us/aqd/Monitoring%20Data.asp

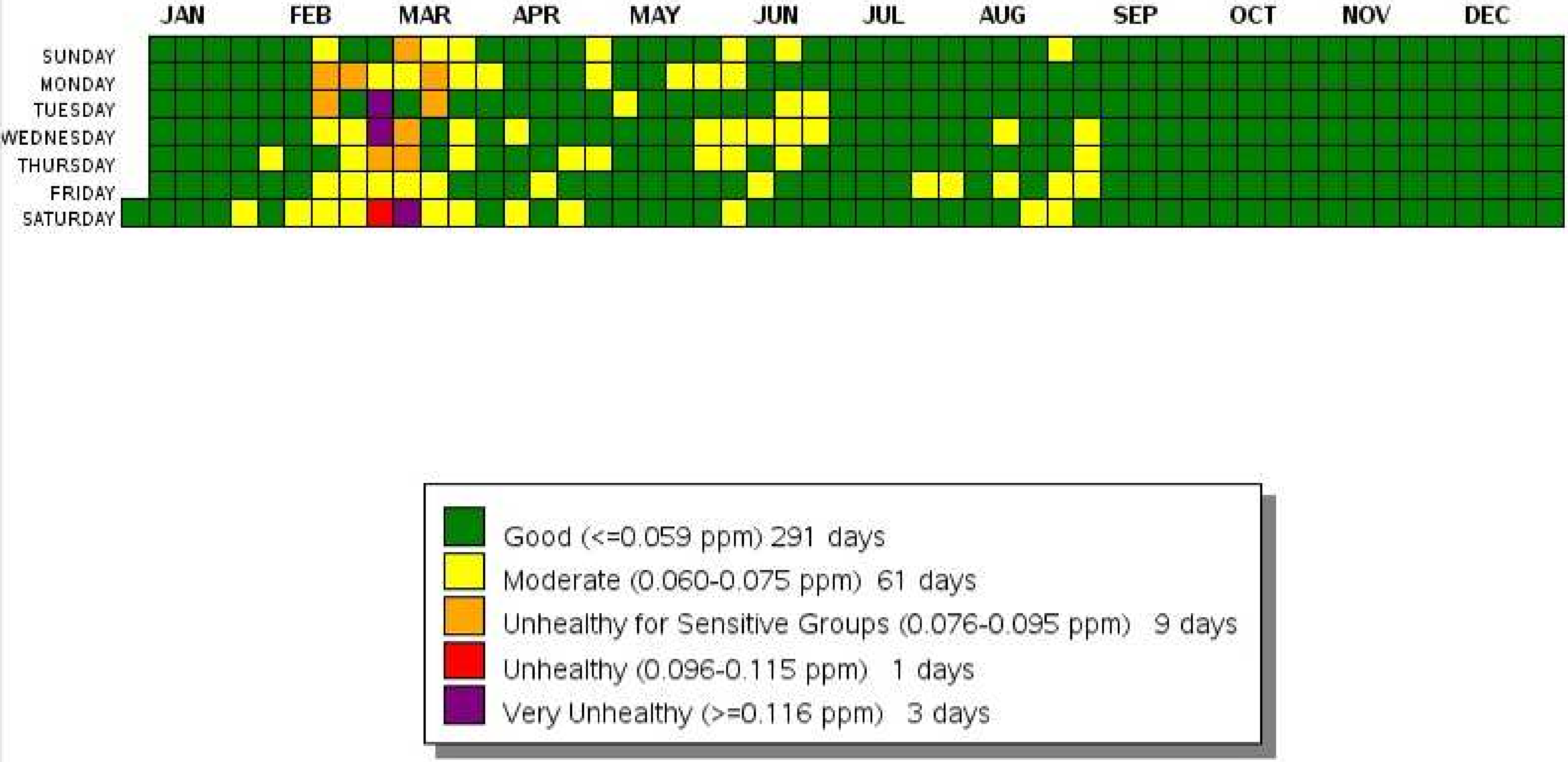
Appendix S.3
Population Density by Census Tract

Appendix S.4.A.
2007 Vehicle Miles on State Highways By County

Appendix S.4.B.
Commuting Patterns in Sublette County

Appendix.
Glossary

Daily Ozone AQI Levels in 2011
Sublette County, WY



Source: EPA's Air Explorer (http://www.epa.gov/airexplorer/)
Generated on: 06NOV12

Report: U.S. coal power plants emit toxic air pollutants

EPA: Energy Star TVs must use 40% less energy

Mar 09, 2011

Wyoming's smog exceeds Los Angeles' due to gas drilling

25 Recommend 2.8k 102 2

By Wendy Koch, USA TODAY

Updated 2011-03-09 11:52 AM

CAPTION By Mead Gruver, AP

Rural Wyoming, known for breathtaking vistas, now has worse smog than Los Angeles because of its boom in natural gas drilling.

Residents who live near the gas fields in the state's western corner are complaining of watery eyes, shortness of breath and bloody noses, reports the Associated Press. The cause is clearer than the air: local ozone levels recently exceeded the highest levels recorded in the biggest U.S. cities last year.

Preliminary data show the region's ozone levels last Wednesday got as high as 124 parts per billion, which is two-thirds higher than the Environmental Protection Agency's maximum healthy limit of 75 parts per billion and above the worst day in Los Angeles all last year, 114 parts per billion, AP reports. On March 1, the ozone levels hit 116 parts per billion.

Last year, too, Wyoming's gas-drilling area had days when its ozone levels exceeded Los Angeles' worst for 2009.

Yet, the Cowboy State is prospering. It has one of the nation's lowest unemployment rates, 6.4 percent, and is expected to run a budget surplus this year.

About Wendy Koch

Wendy Koch has been a reporter and editor at USA TODAY since 1998, covering politics and social issues. She's begun a quest to build the most eco-friendly home her budget allows. She'll share her experience and give you tips for greening your home. More about Wendy

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- Greenopia
- Home & Garden (Consumer Reports)
- Home by Sunset
- Inhabitat
- Jetson Green
- Mother Earth News

"They're trading off health for profit. It's outrageous. We're not a Third World country," said Elaine Crumpley, a retired science teacher who lives just outside Pinedale, Wyo., told the AP.

In the Upper Green River Basin, at least one daycare center called off outdoor recess, and state officials urged the elderly, children and people with respiratory conditions to avoid strenuous or extended outdoor activity.

Gas industry officials say they're trying to curb smog by reducing truck traffic and switching to drilling rigs with pollution control equipment, and they report fewer emissions contributing to smog than in 2008, reports the AP. On Monday, Gov. Matt Mead discussed with state regulators and industry representatives what else companies can do.

See photos of: Los Angeles, Wyoming

TAGS: LOS ANGELES WYOMING ENVIRONMENTAL PROTECTION AGENCY PINEDALE OZONE SMOG COWBOY STATE UPPER GREEN RIVER BASIN

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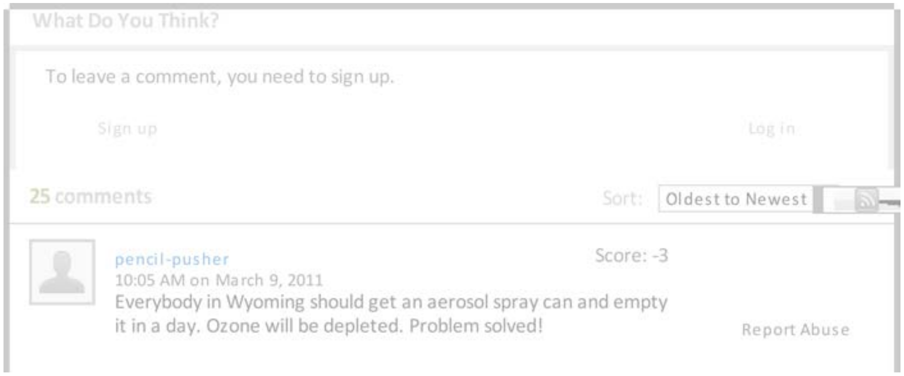

To leave a comment, you need to sign up.

25 comments

pencil-pusher
Score: -3
10:05 AM on March 9, 2011
Everybody in Wyoming should get an aerosol spray can and empty it in a day. Ozone will be depleted. Problem solved!

- Mother Nature Network
- National Geographic
- Natural Home Magazine
- Planet Green
- Re-Nest
- The Daily Green
- The Green Life (Sierra Club)
- Treehugger

smithy46
Score: -8
10:05 AM on March 9, 2011
If the poeple of Wyoming don't grin and bear it then they are America-hating, terrorist-loving, communist sympathizers!! If they're real Americans they'll take a hit for the team.
Report Abuse

mindstorms
Score: 2
10:07 AM on March 9, 2011
Man polluting the environment they live in....I'm shocked?
Report Abuse

John Spencer
Score: 0
10:08 AM on March 9, 2011
Now there's an idea pencil-pusher.
Report Abuse

rawn
Score: 0
10:09 AM on March 9, 2011
Typical red state filled with oil and smog. Texas must be jealous.
Report Abuse

False_Paradigm
Score: 1
10:10 AM on March 9, 2011
DRILL BABY DRILL!!! DERP AH-DERPITY DOO!!!
Report Abuse

foolsarerequired
Score: 6
10:11 AM on March 9, 2011
The gas and oil executives wouldn't have a house no where near this drilling.
Report Abuse

Man the Middle
Score: 0
10:13 AM on March 9, 2011
...and the smell is overwhelming!!!
Report Abuse

Independent01
Score: -1
10:15 AM on March 9, 2011
Oh well just send us your gas.
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Next

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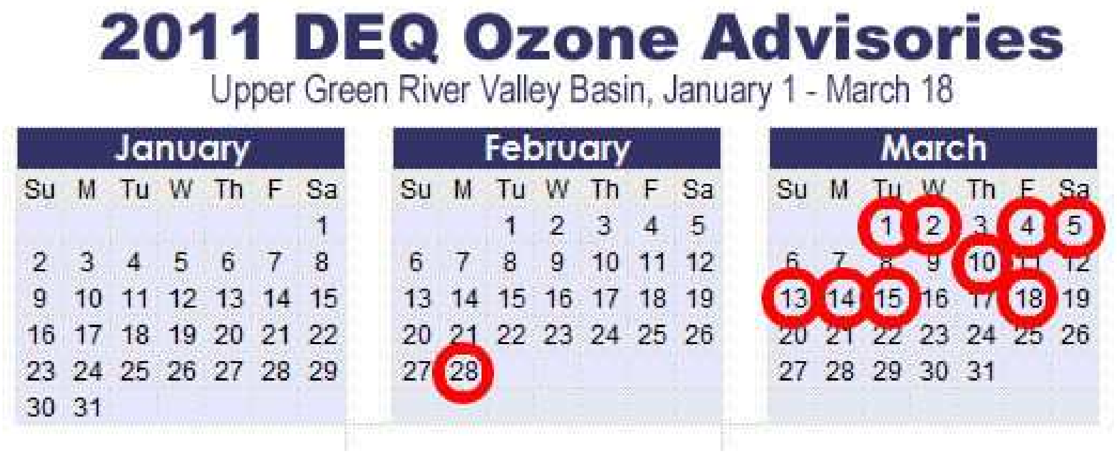
Back to Article



2011 DEQ Ozone Advisories

Upper Green River Valley Basin, January 1 - March 18

January

Su	M	Tu	W	Th	F	Sa
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

February

Su	M	Tu	W	Th	F	Sa
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	**28**					

March

Su	M	Tu	W	Th	F	Sa
		1	**2**	3	**4**	**5**
6	7	8	9	**10**	11	12
13	**14**	**15**	16	17	**18**	19
20	21	22	23	24	25	26
27	28	29	30	31		

© Photo by Pinedale Online

Ozone Calendar

Wyoming DEQ has issued 10 Ozone Advisories for the Upper Green River Basin since February 28, 2011. Actual ozone levels may or may not have exceeded standards on any of those days. DEQ only issues prediction advisories, which are made based on weather predictions the day before they believe conditions may be condusive to creating high ozone levels in a given area. They do not issue a notice or advisory in real time to the public or media when high ozone levels are actually occuring. To see monitor readings in real time, visit the DEQ WYVisNet website. Graphic by Pinedale Online.

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E-mail:support@pinedaleonline.com

Ozone Advisory for Monday, Feb. 28

by Wyoming Department of Environmental Quality

February 27, 2011

Upper Green River Basin, Wyo. - The Air Quality Division (AQD) of Wyoming's Department of Environmental Quality (DEQ), in conjunction with the Wyoming Department of Health (WDH), is issuing an ozone advisory for tomorrow, Monday February 28, 2011, for the Upper Green River Basin, in Sublette County.

The DEQ-AQD would like to communicate that this particular Ozone Advisory is anticipated to be a multi-day event. Weather forecasting for conditions conducive to elevated 8-hour ozone will continue on a daily basis and the AQD will continue to issue updated advisory status by noon each day such that, if the weather forecast changes, advisory status may also change. The DEQ-AQD will also be conducting intensive sampling of ozone and precursors during this period. These intensive measurements will focus on the vertical distributions of pollutants which will be accomplished by equipment attached to weather balloons.

Ozone is an air pollutant that can cause respiratory health effects especially to children, the elderly and people with existing respiratory conditions. People in these sensitive groups should limit strenuous or extended outdoor activities, especially in the afternoon and evening. More information on ozone and the health effects of ozone are available at the Wyoming Department of Health website, .http://www.health.wyo.gov.

An ozone advisory is issued when weather conditions appear to be favorable for the formation of ozone. Ozone appears to be elevated in the Basin when there is a presence of ozone-forming precursor emissions including oxides of nitrogen and volatile organic compounds coupled with strong temperature inversions, low winds, snow cover, and bright sunlight.

Current information on ozone levels at the Air Quality Division's monitoring stations at Daniel, Pinedale, Boulder, Juel Spring and the Wyoming Range can be found at www.wyvisnet.com.

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The New York Times

October 1, 2010

Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future

By SCOTT STREATER of

An energy company's plan to drill more than 1,400 natural gas wells in northeast Utah's Uintah Basin could be tripped up by an emerging air pollution problem that has affected other densely developed oil and gas fields across the Rocky Mountain West.

The concern is wintertime ozone, a problem that federal regulators discovered for the first time in the basin just this year. If the phenomenon cannot be controlled, it could force Denver-based Gasco Energy Inc. to scale back plans to drill across 206,826 acres of mostly Bureau of Land Management property.

Ground-level ozone pollution, which is linked to respiratory diseases like asthma, is a well-known summer pollution problem, stemming from the mixing of auto and industrial emissions in sunlight and heat.

But federal regulators have discovered an unusual winter weather pattern in the Uintah Basin that causes ozone concentrations to reach potentially dangerous levels in January, February and March. The pattern is marked by stagnant air that allows emissions to collect in the lower atmosphere and then be converted into ozone by sunlight and heat reflecting off snow on the ground, said Stephanie Howard, a BLM environmental coordinator and the agency's project manager for the Gasco proposal.

Air pollution monitors recently installed in the Uintah Basin measured ozone concentrations exceeding federal health standards more than 68 times in the first three months of 2010, according to U.S. EPA data. On one day in January and two days in February, recorded ozone levels were nearly twice the federal health standard of 75 parts per billion.

“We think these ozone issues in the Uintah Basin call into question the justifica
moving ahead to analyze or approve these sorts of projects,” said Steve Bloch, director of the Southern Utah Wilderness Alliance.

The winter ozone phenomenon surprised BLM, which this week issued a draft

impact statement (EIS) identifying hundreds of existing oil and gas wells in the basin as the primary cause of the ozone pollution.

The draft EIS is scheduled to be published tomorrow in the *Federal Register*, kicking off a 45-day public comment period through Nov. 15.

Gasco's project could still be permitted, though, since federal regulations require three consecutive years of monitoring data before a region can be deemed a violator of federal pollution standards, also known as National Ambient Air Quality Standards.

If the area were declared an ozone violator, EPA would mandate an emissions reduction plan to improve air quality by a certain deadline.

But BLM is not waiting for such a violation to occur. Rather, the agency's EIS includes measures to ensure the Gasco project does not exacerbate wintertime ozone, including possibly reducing or prohibiting drilling activity during the winter months.

"We're very anxious to see what the numbers are in January, February and March," Howard said. "We're holding our breath to see what happens."

Tougher standards

Further complicating the Gasco proposal is EPA's expected tightening of the ozone health standard by the end of the year.

EPA has proposed revising its "primary" health standard for ozone so that a region would violate the Clean Air Act if ozone concentrations reached between 60 and 70 parts per billion averaged over an eight-hour period. The agency has also proposed a "secondary" ozone standard aimed at protecting vegetation and sensitive ecosystems, including parks, wildlife refuges and wilderness areas (*Greenwire*, Jan. 7).

While a tougher ozone health standard would have its most immediate effect in urban areas, where motor vehicles contribute billions of tons of ozone-forming pollutants annually, the odorless gas has become a growing problem in remote areas as well, especially where oil and gas producers have sunk thousands of wells into the ground, resulting in releases of ozone precursors nitrogen oxide (NOx) and volatile organic compounds (VOCs).

The stakes could be especially high in Utah, one of the nation's fastest-growing states and a growing hub for oil and gas development, particularly within the Uintah Basin.

In fact, the Gasco Energy project is the smallest of four Uintah Basin drilling proposals currently under review by BLM. Collectively, these four projects could result in the drilling of more than 17,000 new natural gas wells across hundreds of thousands of acres of federal land over the next three years.

The largest is the Greater Chapita Wells Natural Gas Infill Project, which would place up to 7,028 wells across more than 40,000 acres of mostly BLM land. Next is the Greater Monument Butte plan, proposed by the Newfield Exploration Co. It calls for drilling 5,750 wells across 119,850 acres of mostly federal land. And finally, the Greater Natural Buttes Project, proposed by Kerr-McGee Oil & Gas Onshore LP, could result in drilling as many as 3,675 wells on 162,911 acres.

While drilling in the Uintah Basin has been going on in some form since the early 1900s, with some active federal leases dating back to the 1950s, Howard said better technologies and drilling techniques have attracted companies looking to access gas reserves at much greater depths than before.

"That's across the West. We are now able to develop more American oil and gas reserves that five, 10 years ago we didn't know how to," said Kathleen Sgamma, director of government affairs for the Denver-based Western Energy Alliance, an industry trade group.

Industry doubts readings

Sgamma, however, questioned the accuracy of the ozone readings in the Uintah Basin, saying the two monitors that registered high wintertime ozone were "faulty," and the readings did not pass EPA's quality assurance standards.

"That data cannot be used in determining the attainment status" of the region, Sgamma said.

Howard, however, disputed the assertion that the numbers were faulty, saying they had been vetted by EPA and posted on its website.

"I'm pretty sure that if the readings were faulty the EPA would not have published them," she said. "My understanding is those numbers are correct."

Faulty or not, Sgamma said the readings provide enough incentive for regulators and the industry to work together to ensure that emissions of ozone precursors stay low.

She also stressed that Uintah County, where the project would be located, currently is in compliance with federal health standards for ozone.

"Environmental groups are certainly trying to use the faulty readings in the basin as a means to stop oil and gas development and the associated jobs," Sgamma said. "But the bottom line is that economic activity does not need to be stopped in an area that remains in compliance for ozone."

Lessons from Wyoming

But the Uintah Basin is not the only place where oil and natural gas drilling activity is associated with high wintertime ozone.

In Sublette County, Wyo., wintertime ozone attributed largely to oil and gas production in the Jonah Infill and Pinedale Anticline gas fields could lead to Wyoming's first violations of EPA air quality standards, according to state officials. Federal maps also indicate that counties in the natural gas-rich Powder River Basin in northeast Wyoming could also violate federal air quality standards if EPA toughens its ozone health standard.

Wyoming Gov. Dave Freudenthal (D) asked EPA last year to designate Sublette County and portions of two other neighboring counties in the state's southwest corner as violating current ozone health standards (*Land Letter*, March 19, 2009). Wells in those two fields produced 7.6 million barrels of oil and 1.1 billion cubic feet of natural gas in 2008, according to state statistics.

Between 2000 and 2008, the number of annual new oil, gas and coalbed methane drilling wells in the region increased almost threefold, from 350 a year in 2000 to 925 a year in 2008, according to state figures. More than 2,600 new wells were drilled in Sublette County alone during that time.

An ozone monitor in southwest Wyoming began recording high ozone levels in 2005, and a technical analysis of air quality in the region conducted last year by the Wyoming Division of Air Quality found that 94 percent of VOCs and 60 percent of NOx emissions "are attributable to oil and gas production and development."

But last winter the region's ozone levels did not exceed federal ozone standards, in part because low wellhead prices significantly slowed production.

Industry officials attribute the drop in emissions to efforts by drillers to reduce emissions by up to 80 percent in the Pinedale Anticline region. Those measures include using cleaner-burning engines in machinery and piping oil and gas to reduce truck traffic in the field.

Meanwhile, BLM will continue to study wintertime ozone levels in Uintah Basin. Howard said the agency would likely allow Gasco to drill some wells before they have collected the three years of data needed to verify that the basin has an ozone problem.

Jeremy Nichols, climate and energy program director for WildEarth Guardians, said that would be a big mistake.

"BLM needs to understand they have a responsibility here, and they do need to start limiting operations and development activity when it looks like emission levels are going to rise," Nichols said. "The only way is to limit operations and limit development. They are going to have to stop rubberstamping all of these projects that are put in front of them."

Click here to read the draft EIS.

Streater writes from Colorado Springs, Colo.

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Exhibit 45

AQS_SIT	POC	SAMPLE_	DAILY_M	UNITS	DAILY_A	DAILY_OB	PERCENT	AQS_PAR
49-047-20	1	1/1/2011	0.039	ppm	33	24	100	44201
49-047-20	1	1/2/2011	0.041	ppm	35	22	92	44201
49-047-20	1	1/3/2011	0.049	ppm	42	20	83	44201
49-047-20	1	1/4/2011	0.058	ppm	49	24	100	44201
49-047-20	1	1/5/2011	0.069	ppm	80	24	100	44201
49-047-20	1	1/6/2011	0.078	ppm	106	24	100	44201
49-047-20	1	1/7/2011	0.092	ppm	142	24	100	44201
49-047-20	1	1/8/2011	0.098	ppm	156	24	100	44201
49-047-20	1	1/9/2011	0.1	ppm	161	22	92	44201
49-047-20	1	1/10/2011	0.049	ppm	42	20	83	44201
49-047-20	1	1/11/2011	0.042	ppm	36	24	100	44201
49-047-20	1	1/12/2011	0.062	ppm	58	24	100	44201
49-047-20	1	1/13/2011	0.073	ppm	93	24	100	44201
49-047-20	1	1/14/2011	0.066	ppm	71	24	100	44201
49-047-20	1	1/15/2011	0.069	ppm	80	24	100	44201
49-047-20	1	1/16/2011	0.086	ppm	127	22	92	44201
49-047-20	1	1/17/2011	0.075	ppm	100	20	83	44201
49-047-20	1	1/18/2011	0.054	ppm	46	24	100	44201
49-047-20	1	1/19/2011	0.07	ppm	84	24	100	44201
49-047-20	1	1/20/2011	0.052	ppm	44	24	100	44201
49-047-20	1	1/21/2011	0.072	ppm	90	24	100	44201
49-047-20	1	1/22/2011	0.075	ppm	100	24	100	44201
49-047-20	1	1/23/2011	0.049	ppm	42	22	92	44201
49-047-20	1	1/24/2011	0.066	ppm	71	20	83	44201
49-047-20	1	1/25/2011	0.056	ppm	47	24	100	44201
49-047-20	1	1/26/2011	0.083	ppm	119	24	100	44201
49-047-20	1	1/27/2011	0.087	ppm	129	24	100	44201
49-047-20	1	1/28/2011	0.091	ppm	140	24	100	44201
49-047-20	1	1/29/2011	0.092	ppm	142	24	100	44201
49-047-20	1	1/30/2011	0.102	ppm	166	22	92	44201
49-047-20	1	1/31/2011	0.088	ppm	132	20	83	44201
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49-047-20	1	2/4/2011	0.053	ppm	45	24	100	44201
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49-047-20	1	2/15/2011	0.133	ppm	208	24	100	44201
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49-047-20	1	2/18/2011	0.054	ppm	46	24	100	44201
49-047-20	1	2/19/2011	0.055	ppm	47	24	100	44201
49-047-20	1	2/20/2011	0.058	ppm	49	22	92	44201

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49-047-200	1	2/24/2011	0.11	ppm	187	24	100	44201
49-047-200	1	2/25/2011	0.082	ppm	116	24	100	44201
49-047-200	1	2/26/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/27/2011	0.06	ppm	51	22	92	44201
49-047-200	1	2/28/2011	0.07	ppm	84	20	83	44201
49-047-200	1	3/1/2011	0.076	ppm	101	24	100	44201
49-047-200	1	3/2/2011	0.092	ppm	142	24	100	44201
49-047-200	1	3/3/2011	0.093	ppm	145	24	100	44201
49-047-200	1	3/4/2011	0.062	ppm	58	24	100	44201
49-047-200	1	3/5/2011	0.066	ppm	71	24	100	44201
49-047-200	1	3/6/2011	0.06	ppm	51	22	92	44201
49-047-200	1	3/7/2011	0.052	ppm	44	20	83	44201
49-047-200	1	3/8/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/9/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/10/2011	0.057	ppm	48	24	100	44201
49-047-200	1	3/11/2011	0.055	ppm	47	24	100	44201
49-047-200	1	3/12/2011	0.05	ppm	42	24	100	44201
49-047-200	1	3/13/2011	0.053	ppm	45	22	92	44201
49-047-200	1	3/14/2011	0.047	ppm	40	20	83	44201
49-047-200	1	3/15/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/16/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/17/2011	0.049	ppm	42	24	100	44201
49-047-200	1	3/18/2011	0.053	ppm	45	24	100	44201
49-047-200	1	3/19/2011	0.056	ppm	47	24	100	44201
49-047-200	1	3/20/2011	0.052	ppm	44	22	92	44201
49-047-200	1	3/21/2011	0.051	ppm	43	20	83	44201
49-047-200	1	3/22/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/23/2011	0.054	ppm	46	18	75	44201
49-047-200	1	3/24/2011	0.055	ppm	47	24	100	44201
49-047-200	1	3/25/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/26/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/27/2011	0.055	ppm	47	22	92	44201
49-047-200	1	3/28/2011	0.052	ppm	44	20	83	44201
49-047-200	1	3/29/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/30/2011	0.041	ppm	35	24	100	44201
49-047-200	1	3/31/2011	0.048	ppm	41	20	83	44201
49-047-200	1	4/1/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/2/2011	0.045	ppm	38	24	100	44201
49-047-200	1	4/3/2011	0.055	ppm	47	22	92	44201
49-047-200	1	4/4/2011	0.05	ppm	42	20	83	44201
49-047-200	1	4/5/2011	0.049	ppm	42	24	100	44201
49-047-200	1	4/6/2011	0.06	ppm	51	24	100	44201
49-047-200	1	4/7/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/8/2011	0.054	ppm	46	24	100	44201
49-047-200	1	4/9/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/10/2011	0.053	ppm	45	22	92	44201
49-047-200	1	4/11/2011	0.051	ppm	43	20	83	44201
49-047-200	1	4/12/2011	0.054	ppm	46	24	100	44201
49-047-200	1	4/13/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/14/2011	0.06	ppm	51	24	100	44201

49-047-200	1	4/15/2011	0.063	ppm	61	24	100	44201
49-047-200	1	4/16/2011	0.052	ppm	44	24	100	44201
49-047-200	1	4/17/2011	0.044	ppm	37	22	92	44201
49-047-200	1	4/18/2011	0.034	ppm	29	20	83	44201
49-047-200	1	4/19/2011	0.048	ppm	41	24	100	44201
49-047-200	1	4/20/2011	0.046	ppm	39	24	100	44201
49-047-200	1	4/21/2011	0.052	ppm	44	24	100	44201
49-047-200	1	4/22/2011	0.061	ppm	54	24	100	44201
49-047-200	1	4/23/2011	0.057	ppm	48	24	100	44201
49-047-200	1	4/24/2011	0.049	ppm	42	22	92	44201
49-047-200	1	4/25/2011	0.054	ppm	46	20	83	44201
49-047-200	1	4/26/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/27/2011	0.056	ppm	47	24	100	44201
49-047-200	1	4/28/2011	0.056	ppm	47	24	100	44201
49-047-200	1	4/29/2011	0.057	ppm	48	24	100	44201
49-047-200	1	4/30/2011	0.047	ppm	40	20	83	44201
49-047-200	1	5/1/2011	0.05	ppm	42	22	92	44201
49-047-200	1	5/2/2011	0.056	ppm	47	20	83	44201
49-047-200	1	5/3/2011	0.053	ppm	45	24	100	44201
49-047-200	1	5/4/2011	0.064	ppm	64	24	100	44201
49-047-200	1	5/6/2011	0.057	ppm	48	24	100	44201
49-047-200	1	5/7/2011	0.065	ppm	67	24	100	44201
49-047-200	1	5/8/2011	0.055	ppm	47	22	92	44201
49-047-200	1	5/9/2011	0.072	ppm	90	20	83	44201
49-047-200	1	5/10/2011	0.059	ppm	50	24	100	44201
49-047-200	1	5/11/2011	0.042	ppm	36	24	100	44201
49-047-200	1	5/12/2011	0.055	ppm	47	24	100	44201
49-047-200	1	5/13/2011	0.052	ppm	44	24	100	44201
49-047-200	1	5/14/2011	0.053	ppm	45	24	100	44201
49-047-200	1	5/15/2011	0.046	ppm	39	22	92	44201
49-047-200	1	5/16/2011	0.051	ppm	43	20	83	44201
49-047-200	1	5/17/2011	0.051	ppm	43	24	100	44201
49-047-200	1	5/18/2011	0.06	ppm	51	24	100	44201
49-047-200	1	5/19/2011	0.061	ppm	54	24	100	44201
49-047-200	1	5/20/2011	0.052	ppm	44	24	100	44201
49-047-200	1	5/21/2011	0.054	ppm	46	24	100	44201
49-047-200	1	5/22/2011	0.05	ppm	42	22	92	44201
49-047-200	1	5/23/2011	0.058	ppm	49	20	83	44201
49-047-200	1	5/24/2011	0.056	ppm	47	24	100	44201
49-047-200	1	5/25/2011	0.059	ppm	50	24	100	44201
49-047-200	1	5/27/2011	0.056	ppm	47	24	100	44201
49-047-200	1	5/28/2011	0.047	ppm	40	24	100	44201
49-047-200	1	5/30/2011	0.052	ppm	44	20	83	44201
49-047-200	1	5/31/2011	0.056	ppm	47	24	100	44201
49-047-200	1	6/1/2011	0.055	ppm	47	24	100	44201
49-047-200	1	6/2/2011	0.064	ppm	64	24	100	44201
49-047-200	1	6/3/2011	0.061	ppm	54	24	100	44201
49-047-200	1	6/4/2011	0.06	ppm	51	24	100	44201
49-047-200	1	6/5/2011	0.045	ppm	38	22	92	44201
49-047-200	1	6/6/2011	0.051	ppm	43	20	83	44201
49-047-200	1	6/7/2011	0.05	ppm	42	24	100	44201
49-047-200	1	6/8/2011	0.059	ppm	50	24	100	44201

49-047-200	1	6/9/2011	0.063	ppm	61	24	100	44201
49-047-200	1	6/10/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/11/2011	0.062	ppm	58	24	100	44201
49-047-200	1	6/12/2011	0.062	ppm	58	22	92	44201
49-047-200	1	6/13/2011	0.061	ppm	54	20	83	44201
49-047-200	1	6/14/2011	0.067	ppm	74	24	100	44201
49-047-200	1	6/15/2011	0.062	ppm	58	24	100	44201
49-047-200	1	6/16/2011	0.053	ppm	45	24	100	44201
49-047-200	1	6/17/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/18/2011	0.058	ppm	49	24	100	44201
49-047-200	1	6/19/2011	0.045	ppm	38	22	92	44201
49-047-200	1	6/20/2011	0.043	ppm	36	20	83	44201
49-047-200	1	6/22/2011	0.065	ppm	67	24	100	44201
49-047-200	1	6/23/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/24/2011	0.054	ppm	46	24	100	44201
49-047-200	1	6/25/2011	0.055	ppm	47	24	100	44201
49-047-200	1	6/26/2011	0.06	ppm	51	22	92	44201
49-047-200	1	6/27/2011	0.057	ppm	48	20	83	44201
49-047-200	1	6/28/2011	0.056	ppm	47	24	100	44201
49-047-200	1	6/29/2011	0.051	ppm	43	24	100	44201
49-047-200	1	6/30/2011	0.06	ppm	51	20	83	44201
49-047-200	1	1/1/2011	0.04	ppm	34	24	100	44201
49-047-200	1	1/2/2011	0.039	ppm	33	22	92	44201
49-047-200	1	1/3/2011	0.05	ppm	42	20	83	44201
49-047-200	1	1/4/2011	0.059	ppm	50	24	100	44201
49-047-200	1	1/5/2011	0.066	ppm	71	24	100	44201
49-047-200	1	1/6/2011	0.079	ppm	109	24	100	44201
49-047-200	1	1/7/2011	0.088	ppm	132	24	100	44201
49-047-200	1	1/8/2011	0.094	ppm	147	24	100	44201
49-047-200	1	1/9/2011	0.082	ppm	116	22	92	44201
49-047-200	1	1/10/2011	0.043	ppm	36	20	83	44201
49-047-200	1	1/11/2011	0.041	ppm	35	24	100	44201
49-047-200	1	1/12/2011	0.056	ppm	47	24	100	44201
49-047-200	1	1/13/2011	0.079	ppm	109	23	96	44201
49-047-200	1	1/15/2011	0.067	ppm	74	24	100	44201
49-047-200	1	1/16/2011	0.081	ppm	114	22	92	44201
49-047-200	1	1/17/2011	0.063	ppm	61	20	83	44201
49-047-200	1	1/18/2011	0.049	ppm	42	24	100	44201
49-047-200	1	1/19/2011	0.047	ppm	40	24	100	44201
49-047-200	1	1/20/2011	0.045	ppm	38	24	100	44201
49-047-200	1	1/21/2011	0.061	ppm	54	24	100	44201
49-047-200	1	1/22/2011	0.055	ppm	47	24	100	44201
49-047-200	1	1/24/2011	0.061	ppm	54	20	83	44201
49-047-200	1	1/25/2011	0.061	ppm	54	24	100	44201
49-047-200	1	1/26/2011	0.076	ppm	101	24	100	44201
49-047-200	1	1/27/2011	0.077	ppm	104	24	100	44201
49-047-200	1	1/28/2011	0.081	ppm	114	24	100	44201
49-047-200	1	1/29/2011	0.084	ppm	122	24	100	44201
49-047-200	1	1/30/2011	0.089	ppm	135	22	92	44201
49-047-200	1	1/31/2011	0.072	ppm	90	20	83	44201
49-047-200	1	2/1/2011	0.044	ppm	37	24	100	44201
49-047-200	1	2/2/2011	0.041	ppm	35	24	100	44201

49-047-200	1	2/3/2011	0.045	ppm	38	24	100	44201
49-047-200	1	2/4/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/5/2011	0.06	ppm	51	24	100	44201
49-047-200	1	2/6/2011	0.055	ppm	47	22	92	44201
49-047-200	1	2/7/2011	0.057	ppm	48	20	83	44201
49-047-200	1	2/8/2011	0.04	ppm	34	24	100	44201
49-047-200	1	2/9/2011	0.048	ppm	41	24	100	44201
49-047-200	1	2/10/2011	0.056	ppm	47	24	100	44201
49-047-200	1	2/11/2011	0.072	ppm	90	24	100	44201
49-047-200	1	2/12/2011	0.086	ppm	127	24	100	44201
49-047-200	1	2/13/2011	0.1	ppm	161	22	92	44201
49-047-200	1	2/14/2011	0.119	ppm	202	20	83	44201
49-047-200	1	2/15/2011	0.108	ppm	182	9	38	44201
49-047-200	1	2/16/2011	0.125	ppm	204	17	71	44201
49-047-200	1	2/17/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/18/2011	0.052	ppm	44	24	100	44201
49-047-200	1	2/19/2011	0.07	ppm	84	24	100	44201
49-047-200	1	2/20/2011	0.059	ppm	50	22	92	44201
49-047-200	1	2/21/2011	0.065	ppm	67	20	83	44201
49-047-200	1	2/22/2011	0.083	ppm	119	17	71	44201
49-047-200	1	2/23/2011	0.085	ppm	124	24	100	44201
49-047-200	1	2/24/2011	0.073	ppm	93	24	100	44201
49-047-200	1	2/25/2011	0.06	ppm	51	24	100	44201
49-047-200	1	2/26/2011	0.054	ppm	46	24	100	44201
49-047-200	1	2/27/2011	0.062	ppm	58	22	92	44201
49-047-200	1	2/28/2011	0.068	ppm	77	20	83	44201
49-047-200	1	3/1/2011	0.092	ppm	142	24	100	44201
49-047-200	1	3/2/2011	0.08	ppm	111	24	100	44201
49-047-200	1	3/3/2011	0.077	ppm	104	24	100	44201
49-047-200	1	3/4/2011	0.058	ppm	49	24	100	44201
49-047-200	1	3/5/2011	0.055	ppm	47	24	100	44201
49-047-200	1	3/6/2011	0.05	ppm	42	22	92	44201
49-047-200	1	3/7/2011	0.052	ppm	44	20	83	44201
49-047-200	1	3/8/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/9/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/10/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/11/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/12/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/13/2011	0.054	ppm	46	22	92	44201
49-047-200	1	3/14/2011	0.049	ppm	42	20	83	44201
49-047-200	1	3/15/2011	0.049	ppm	42	24	100	44201
49-047-200	1	3/16/2011	0.042	ppm	36	24	100	44201
49-047-200	1	3/17/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/18/2011	0.052	ppm	44	24	100	44201
49-047-200	1	3/19/2011	0.051	ppm	43	24	100	44201
49-047-200	1	3/20/2011	0.05	ppm	42	22	92	44201
49-047-200	1	3/21/2011	0.05	ppm	42	20	83	44201
49-047-200	1	3/23/2011	0.049	ppm	42	24	100	44201
49-047-200	1	3/24/2011	0.053	ppm	45	24	100	44201
49-047-200	1	3/25/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/26/2011	0.048	ppm	41	24	100	44201
49-047-200	1	3/27/2011	0.052	ppm	44	22	92	44201

49-047-200	1	3/28/2011	0.049	ppm	42	20	83	44201
49-047-200	1	3/29/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/30/2011	0.042	ppm	36	24	100	44201
49-047-200	1	3/31/2011	0.045	ppm	38	20	83	44201
49-047-200	1	4/1/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/2/2011	0.045	ppm	38	24	100	44201
49-047-200	1	4/3/2011	0.055	ppm	47	22	92	44201
49-047-200	1	4/4/2011	0.05	ppm	42	20	83	44201
49-047-200	1	4/5/2011	0.043	ppm	36	24	100	44201
49-047-200	1	4/6/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/7/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/8/2011	0.051	ppm	43	24	100	44201
49-047-200	1	4/9/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/10/2011	0.053	ppm	45	22	92	44201
49-047-200	1	4/11/2011	0.052	ppm	44	20	83	44201
49-047-200	1	4/12/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/13/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/14/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/15/2011	0.063	ppm	61	24	100	44201
49-047-200	1	4/16/2011	0.051	ppm	43	24	100	44201
49-047-200	1	4/17/2011	0.045	ppm	38	22	92	44201
49-047-200	1	4/18/2011	0.032	ppm	27	20	83	44201
49-047-200	1	4/19/2011	0.047	ppm	40	24	100	44201
49-047-200	1	4/20/2011	0.046	ppm	39	24	100	44201
49-047-200	1	4/21/2011	0.05	ppm	42	24	100	44201
49-047-200	1	4/22/2011	0.058	ppm	49	24	100	44201
49-047-200	1	4/23/2011	0.057	ppm	48	24	100	44201
49-047-200	1	4/24/2011	0.046	ppm	39	22	92	44201
49-047-200	1	4/25/2011	0.051	ppm	43	20	83	44201
49-047-200	1	4/26/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/27/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/28/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/29/2011	0.056	ppm	47	24	100	44201
49-047-200	1	4/30/2011	0.045	ppm	38	24	100	44201
49-047-200	1	5/1/2011	0.05	ppm	42	22	92	44201
49-047-200	1	5/2/2011	0.056	ppm	47	20	83	44201
49-047-200	1	5/3/2011	0.052	ppm	44	24	100	44201
49-047-200	1	5/5/2011	0.056	ppm	47	24	100	44201
49-047-200	1	5/6/2011	0.056	ppm	47	24	100	44201
49-047-200	1	5/7/2011	0.063	ppm	61	24	100	44201
49-047-200	1	5/8/2011	0.055	ppm	47	24	100	44201
49-047-200	1	5/9/2011	0.062	ppm	58	24	100	44201
49-047-200	1	5/10/2011	0.057	ppm	48	24	100	44201
49-047-200	1	5/11/2011	0.039	ppm	33	24	100	44201
49-047-200	1	5/12/2011	0.052	ppm	44	24	100	44201
49-047-200	1	5/13/2011	0.048	ppm	41	24	100	44201
49-047-200	1	5/14/2011	0.047	ppm	40	24	100	44201
49-047-200	1	5/15/2011	0.044	ppm	37	24	100	44201
49-047-200	1	5/16/2011	0.05	ppm	42	24	100	44201
49-047-200	1	5/17/2011	0.051	ppm	43	24	100	44201
49-047-200	1	5/18/2011	0.053	ppm	45	24	100	44201
49-047-200								

49-047-20(	1	5/20/2011	0.05	ppm	42	24	100	44201
49-047-20(	1	5/21/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	5/22/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	5/23/2011	0.057	ppm	48	23	96	44201
49-047-20(	1	5/24/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	5/25/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	5/26/2011	0.054	ppm	46	22	92	44201
49-047-20(	1	5/27/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	5/28/2011	0.045	ppm	38	24	100	44201
49-047-20(	1	5/29/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	5/30/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	5/31/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	6/1/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	6/2/2011	0.062	ppm	58	24	100	44201
49-047-20(	1	6/3/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	6/4/2011	0.058	ppm	49	24	100	44201
49-047-20(	1	6/5/2011	0.041	ppm	35	22	92	44201
49-047-20(	1	6/6/2011	0.052	ppm	44	20	83	44201
49-047-20(	1	6/7/2011	0.049	ppm	42	24	100	44201
49-047-20(	1	6/8/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	6/9/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	6/10/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	6/11/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	6/12/2011	0.06	ppm	51	22	92	44201
49-047-20(	1	6/13/2011	0.06	ppm	51	20	83	44201
49-047-20(	1	6/14/2011	0.063	ppm	61	24	100	44201
49-047-20(	1	6/15/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	6/16/2011	0.05	ppm	42	24	100	44201
49-047-20(	1	6/17/2011	0.057	ppm	48	23	96	44201
49-047-20(	1	6/18/2011	0.058	ppm	49	24	100	44201
49-047-20(	1	6/19/2011	0.047	ppm	40	22	92	44201
49-047-20(	1	6/21/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	6/22/2011	0.07	ppm	84	24	100	44201
49-047-20(	1	6/23/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	6/24/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	6/25/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	6/26/2011	0.06	ppm	51	22	92	44201
49-047-20(	1	6/27/2011	0.058	ppm	49	20	83	44201
49-047-20(	1	6/28/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	6/29/2011	0.052	ppm	44	24	100	44201
49-047-20(								

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Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
				Not in a MS				

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Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
Ozone	0	Not in a CM	0	Not in a MS	49	Utah	47	Uintah
				Not in a MS				

CITY_CO	CITY	UAR_COD	UAR	LATITUDE	LONGITU	LOCATIO	LANDUSE	ELEVATIO
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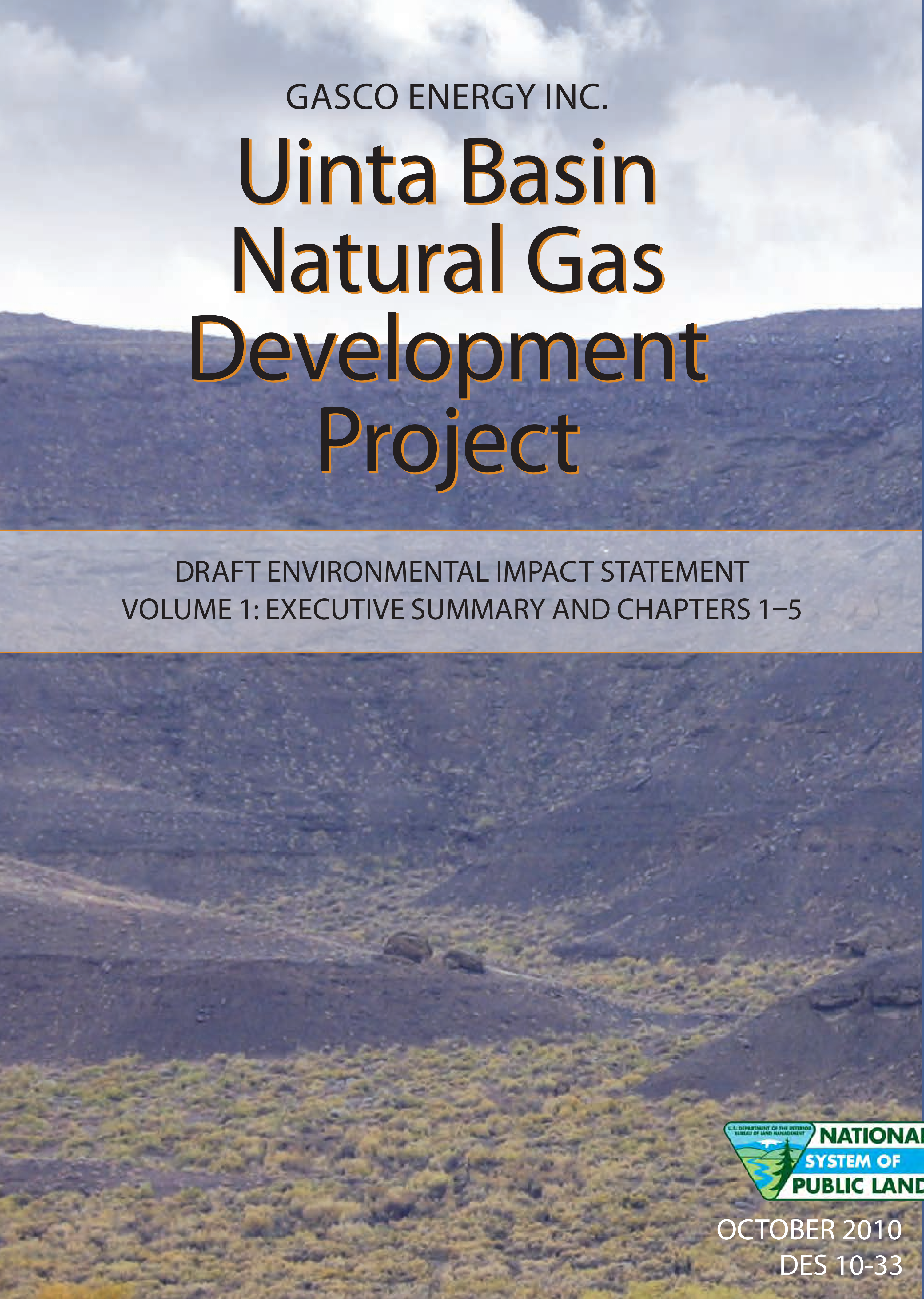


GASCO ENERGY INC.

Uinta Basin Natural Gas Development Project

DRAFT ENVIRONMENTAL IMPACT STATEMENT
VOLUME 1: EXECUTIVE SUMMARY AND CHAPTERS 1–5

BLM

Vernal Field Office

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT
NATIONAL
SYSTEM OF
PUBLIC LANDS

OCTOBER 2010
DES 10-33

The next best method for estimating existing air quality is based on air monitoring conducted that, while not meeting the standards described above, is still considered of sufficient quality to be used for modeling and initial or screening air quality determinations. Reasons for monitoring not meeting NAAQS CFR standards, but still be sufficient for other purposes, might include use of non-FRM certified monitors, not meeting all CFR standards for the monitoring site, or operating otherwise compliant monitors less than the averaging time of the applicable pollutant standard (e.g., less than three years for ozone). Air monitoring data over ten years old are generally considered to be out of date, though they still may be representative if emission sources in the area have not changed much. Given these qualifiers, there has been relevant air monitoring conducted recently in the Uinta Basin for $PM_{2.5}$ and ozone.

3.2.3.1.5.1 $PM_{2.5}$ Air Monitoring

Starting in December 2006 and running through December 2007, the Utah Department of Environmental Quality (UDAQ) conducted air monitoring for $PM_{2.5}$ in the town of Vernal, Uintah County. Over the winter, $PM_{2.5}$ levels were measured at the Vernal monitoring station that were higher than the new $PM_{2.5}$ NAAQS that became effective in December 2006. The maximum 24-hour average concentration over this period was 63.3 ug/m^3. Additional $PM_{2.5}$ monitoring was conducted by UDAQ in Vernal in 2008 and in Vernal and Roosevelt (Duchesne County) in 2009, which also monitored maximum 24-hour values above the NAAQS during the winter months. $PM_{2.5}$ monitoring conducted by UDAQ during the summer of 2007 did not find any elevated concentrations. A limited analysis of the filters used to collect the $PM_{2.5}$ samples was conducted to chemically speciate the particulate samples. This analysis found that the composition was primarily carbon-based. In the case of Teflon filters, the composition was unidentifiable, which in a Teflon filter is typically indicative of also being carbonaceous because these types of filters cannot be used to detect carbon-based particulate.

Beginning in the summer of 2009, $PM_{2.5}$ monitoring is being conducted in the Ouray and Redwash areas of Uintah County. This monitoring is being conducted to comply with an EPA consent order. It is located in a rural area contingent with oil and gas operations and removed from urban sources. No exceedences of the $PM_{2.5}$ 24-hour standard have been observed.

The sources of elevated $PM_{2.5}$ concentrations during winter inversions in Vernal and Roosevelt have not been conclusively identified yet. Based on experiences and studies in other areas of the Rocky Mountain west and the emission inventory in the Uinta Basin, potential sources can be tentatively identified. In Utah, elevated $PM_{2.5}$ concentrations along the Wasatch Front are associated with secondarily formed particles from sulfates, nitrates, and organic chemicals from a variety of sources (UDAQ 2006). In Cache Valley, approximately half of ambient $PM_{2.5}$ during elevated concentrations is composed of ammonium nitrate, most likely from agricultural operations. The other half is from combustion, primarily mobile sources and woodstoves (Martin 2006). For comparison, $PM_{2.5}$ in most rural areas in the western United States is typically dominated by total carbonaceous mass and crustal materials from combustion activities and fugitive dust, respectively (EPA 2009). Because the Uinta Basin is not a major metropolitan area (like those found on the Wasatch Front) nor does it have significant agricultural activities (like those found in Cache Valley), the most likely causes of elevated $PM_{2.5}$ at the Vernal monitoring station are probably those common to other areas of the western US (combustion and dust). The filter speciation that has been done to date tends to support this conclusion because the dominant chemical species from the filters is carbonaceous mass, which is indicative of wood burning, diesel emissions, or both. It is unlikely that significant transport of $PM_{2.5}$ precursors are occurring during the intense winter inversions under which these elevated $PM_{2.5}$ levels are forming, and as there is extensive snow cover during these episodes fugitive dust is also an unlikely significant contributor.

The complete UDAQ $PM_{2.5}$ monitoring data can be found at http://www.airmonitoring.utah.gov/dataarchive/archpm25.htm

3.2.3.1.5.2 Ozone Air Monitoring

Active ozone monitoring in the Uinta Basin began in the summer of 2009 at the Ouray and Redwash monitoring sites (the ozone monitors are collocated with the $PM_{2.5}$ monitors). Both sites have recorded numerous exceedences of the 8-hour ozone standard during the winter months (January through March). The maximum 8-hour average recorded to date is 0.123 ppm, well above the current ozone NAAQS of 0.075 ppm. These data have recently been released by EPA. Although the monitors are not currently being operated to CFR standards, and are not considered adequate data to make a NAAQS determination, the data are considered viable and representative of the area. Apparently, high concentrations of ozone are being formed under a ~~–c~~old pool” process, whereby stagnate air conditions with very low mixing heights form under clear skies with snow-covered ground and abundant sunlight that, combined with area precursor emissions (NO_x and VOCs), create intense episodes of ozone. Based on the first year of monitoring, these episodes occur only during the winter months (January through March). This phenomenon has also been observed in similar types of locations in Wyoming, and has contributed to a proposed nonattainment designation for Sublette County.

The National Park Service also operates an ozone monitor in Dinosaur National Monument during the summer months. No exceedences of the current ozone NAAQS have been recorded at this site.

Winter ozone formation is a newly recognized issue, and the methods of analyzing and managing this problem are still in development. Existing photochemical models are currently unable to replicate winter ozone formation satisfactorily, in part due to the very low mixing heights associated with the unique meteorology of these ambient conditions.

Based on the emission inventories developed for Uintah County, the likely dominant source of ozone precursors at the Ouray and Redwash monitoring sites are oil and gas operations near the monitors. The monitors are located in remote areas where impacts from other human activities are unlikely to be significantly contributing to this ozone formation. Although ozone precursors can be transported large distances, the meteorological conditions under which this cold pool ozone formation is occurring tend to preclude any significant transport. Currently, ozone exceedences in this area are confined to the winter months during periods of intense surface inversions and low mixing heights. Significant work remains to definitively identify the sources of ozone precursors contributing to the observed ozone concentrations. Speciation of gaseous air samples collected during periods of high ozone is needed to determine which VOCs are present and what their likely sources are.

The complete EPA Ouray and Redwash monitoring data can be found here: http://www.epa.gov/airexplorer/index.htm

4.2 AIR QUALITY

Air quality impacts were evaluated for both near-field and far-field impacts. Near-field impacts quantify the direct and indirect local impacts created by each alternative, while far-field impacts describe the potential impacts at locations a significant distance away from the project area.

4.2.1 NEAR-FIELD AIR QUALITY

The near-field analysis considered potential impacts to air quality that may occur within 3 miles (5 km) of the project area. The Near-Field Air Quality Technical Support Document (Buys & Associates 2008b and Appendix H) presents a complete description of the project emissions, the modeling protocol, and modeling results. There are two types of activities associated with each alternative that were evaluated for impacts to air quality; development and operations. Development includes: the construction of individual well pads and associated access roads, drilling, and completion activities. Operations include the running of equipment associated with production and the associated truck traffic.

Dispersion modeling was performed for all alternatives to evaluate both development and operational impacts. The AERMOD model (version 07026) was used to predict the impacts of pollutant emissions for comparison to the NAAQS for CO, SO_2, PM_{10}, and $PM_{2.5}$. Because development activities are temporary and short-term in nature, comparisons to PSD increments are not appropriate. AERMOD was used to predict impacts of NO_x emissions as a surrogate for NO_2. The meteorological data used were from surface and upper air stations developed for the *West Tavaputs Environmental Impact Statement* (BLM 2008d). Additional details about the modeling are in the Near-Field Air Quality Technical Support Document (Buys & Associates 2008b and Appendix H).

4.2.1.1 DEVELOPMENT

Near-field impacts from development activities are predominantly short-term and localized to the nearby area. Pollutant emissions from development activities include the following sources:

- Well pad and road construction: equipment producing fugitive dust while moving and leveling earth;
- Drilling: vehicles generating fugitive dust on access roads, and drill rig engine exhaust;
- Completion: vehicles generating fugitive dust on access roads, frac pump engine and generator emissions, and completion venting emissions;
- Vehicle tailpipe emissions associated with all development phases;

Pollutant emissions generated from development sources are summarized in Table 4-2.

Table 4-2. Annual Well Development Emissions for Each Alternative

Pollutant	Well Development Emissions (tons/year)				
	Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D (No Action)	Alternative E (Directional)
Criteria Pollutants & VOC					
NO_x	1,298	1,027	1,357	511	1,762
CO	421	332	444	167	522
VOC	103	81.5	113	42.6	116
SO_2	23.2	18.3	23.9	9.01	30.8
PM_{10}	4,079	3,228	4,486	1,700	3,641
$PM_{2.5}$	433	343	476	180	395
Hazardous Air Pollutants					
Benzene	0.62	0.49	0.69	0.26	0.66
Toluene	1.06	0.84	1.17	0.44	1.08
Ethylbenzene	0.04	0.03	0.04	0.02	0.04
Xylene	0.55	0.44	0.61	0.23	0.56
n-Hexane	1.21	0.96	1.33	0.50	1.21
Formaldehyde	0.44	0.35	0.48	0.18	0.14
Acetaldehyde	3.34×10^{-03}	2.64×10^{-03}	3.67×10^{-03}	1.38×10^{-03}	4.62×10^{-03}
Acrolein	1.04×10^{-03}	8.23×10^{-04}	1.14×10^{-03}	4.31×10^{-04}	1.44×10^{-03}
1,3-Butadiene	1.34×10^{-06}	1.06×10^{-06}	1.48×10^{-06}	5.60×10^{-07}	1.34×10^{-06}
Naphthalene	0.02	0.01	0.02	0.01	0.02
Total HAPs	4.14	3.25	4.51	1.71	3.80
Greenhouse Gases					
CO_2	63,870	50,564	70,257	26,473	86,970
CH_4	517	409	568	215	530

4.2.1.1.1 DEVELOPMENT IMPACTS

Table 4-3 shows all pollutants modeled for development for the Proposed Action compared to the NAAQS. The maximum modeled concentration for NO_2 reflects an adjustment by a factor of 0.75, in accordance with standard EPA methodology (60:153 FR 40469, Aug 9, 1995) to convert from the modeled NO_x annual concentration to a NO_2 annual concentration. The modeling showed that no exceedances of NAAQS would be predicted for all development activities. The annual results demonstrate that even if these activities lasted for an entire year in the same location, the effects would be less than all applicable standards.

Table 4-19. Carcinogenic HAP MEI Risk for Each Alternative

Hazardous Air Pollutant	Cancer Risk				
	Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D (No Action)	Alternative E (Directional)
Dichlorobenzene	4.2 x10^{-10}	3.5 x10^{-10}	5.0 x10^{-10}	7.1 x10^{-11}	2.8 x10^{-10}
Ethylene Dibromide	4.8 x10^{-07}	3.4 x10^{-07}	5.5 x10^{-07}	1.4 x10^{-07}	3.4 x10^{-07}
Methylene Chloride	1.7 x10^{-10}	1.2 x10^{-10}	1.9 x10^{-10}	4.8 x10^{-11}	1.2 x10^{-10}
Naphthalene	3.6 x10^{-08}	3.4 x10^{-08}	5.6 x10^{-08}	1.1 x10^{-08}	3.4 x10^{-08}
Vinyl Chloride	2.4 x10^{-10}	1.7 x10^{-10}	2.7 x10^{-10}	6.7 x10^{-11}	1.7 x10^{-10}
Benzo(b)fluoranthene[a]	3.3 x10^{-10}	2.3 x10^{-10}	3.8 x10^{-10}	9.4 x10^{-11}	2.3 x10^{-10}
Chrysene[a]	1.4 x10^{-10}	9.8 x10^{-11}	1.6 x10^{-10}	3.9 x10^{-11}	2.3 x10^{-11}
TOTAL MEI RISK	**5.9 x10^{-06}**	**4.3 x10^{-06}**	**6.9 x10^{-06}**	**1.7 x10^{-06}**	**5.0 x10^{-06}**

[a] Pollutant is a HAP because it is polycyclic organic matter (POM).

4.2.1.2.4 SUMMARY OF OPERATIONS IMPACTS

Implementation of the Proposed Action or Alternatives would cause increases in criteria pollutants. Potential modeled impacts for Alternative C are predicted to exceed the NAAQS for PM_{10}. Potential modeled impacts for Alternatives A, B, C, and E exceed the PSD Class II increment for PM_{10}. The distribution of concentration contours indicates that the source of the maximum PM_{10} concentrations is road traffic (see Figure 4-1). Predicted concentration contours are similar for PM_{10} and $PM_{2.5}$; the Near-Field Air Quality Technical Support Document (Buys & Associates 2008b and Appendix H) includes figures of $PM_{2.5}$ contours for each alternative showing the maximum concentrations are the result of truck traffic. Therefore none of the alternatives exceed PSD Class II increments (PSD increments do not apply to mobile sources).

Implementation of the Proposed Action or Alternatives would cause increases in HAP concentrations. The increased potential concentration would be long term, lasting the life of the project (LOP; 45 years). None of the alternatives would exceed the Utah TSLs. Potential impacts for all alternatives exceed the REL for acrolein. Alternatives A, B, C, and E are predicted to exceed the RfC for acrolein. Predicted concentrations for all alternatives are below the acute exposure guideline level for acrolein. Predicted concentrations for all alternatives are below the California EPA chronic REL (similar to the RfC) for acrolein. Minor increases in cancer risk are predicted to occur for all alternatives. However, the predicted incremental cancer risks would occur only within relatively small areas. The following tables (Tables 4-20 through 4-24) summarize the operational impacts for each alternative after full field development.

Table 4-20. Summary of Near-Field Operation Maximum Impacts

Pollutant and Averaging Period	Averaging Period	Percent of NAAQS (Project + Background)				
		Alternative A (Proposed Action)	**Alternative B (Reduced)**	**Alternative C (Full)**	**Alternative D No Action)**	**Alternative E (Directional)**
NO_2	Annual	19.3%	17.9%	18.8%	18.0%	18.7%
PM_{10}	24-hour	99.7%	86.6%	112%	56.1%	87.0%
$PM_{2.5}$	Annual	68.7	88.7%	90.7%	76.7%	88.7%
	24-hour	66.0%	60.9%	70.3%	48.6%	61.1%
CO	1-hour	3.33%	3.07%	3.30%	2.94%	3.07%
	8-hour	12.0%	11.5%	11.8%	11.4%	11.7%

Table 4-21. Summary of Near-Field Operation Maximum Impacts to PSD Class II Increments

Pollutant and Averaging Period	Averaging Period	Percent of PSD Class II Increment				
		Alternative A (Proposed Action)	**Alternative B (Reduced)**	**Alternative C (Full)**	**Alternative D (No Action)**	**Alternative E (Directional)**
NO_2	Annual	9.12%	3.78%	7.20%	3.90%	3.78%
PM_{10}	24-hour	287%	222%	357%	69%	222%

Table 4-22. Summary of HAP REL Operation Impacts for Each Alternative

HAP	REL	Percent of REL				
	(µg/m³)	**Alternative A (Proposed Action)**	**Alternative B (Reduced)**	**Alternative C (Full)**	**Alternative D (No Action)**	**Alternative E (Directional)**
Acrolein	0.19[a]	1,189%	868%	1,479%	289%	868%
	69[b]	3.28%	2.39%	4.07%	0.80%	2.39%
	230[c]	0.98%	0.72%	1.22%	0.24%	0.72%
	450[d]	0.50%	0.37%	0.62%	0.12%	0.37%
Formaldehyde	94[a]	24.8%	18.0%	30.7%	6.00%	18.0%
Acetaldehyde	81000[b]	0.01%	0.01%	0.02%	<0.01%	0.01%
Benzene	1,300[a,e]	0.86%	0.62%	0.83%	0.21%	0.62%
	160,000[d]	0.02%	0.01%	0.01%	<0.01%	0.01%
Toluene	37,000[a]	0.19%	0.12%	0.18%	0.04%	0.12%
Ethylbenzene	350,000[d]	<0.01%	<0.01%	<0.01%	<0.01%	<0.01%
Xylenes	22,000[a]	0.32%	0.20%	0.31%	0.07%	0.20%

Ozone Impact Assessment

for

GASCO Energy Inc.
Uinta Basin Natural Gas Development Project Environmental Impact Statement

Prepared for: Bureau of Land Management
Vernal Field Office
Vernal, Utah

Prepared by: Alpine Geophysics, LLC
Arvada, CO
Dennis McNally
Cyndi Loomis

and

Buys and Associates Environmental Consultants
Littleton, CO
Daniel Pring
Doug Henderer

April 2010

1.0 Introduction

Gasco Production Company (Gasco) has proposed to the United States Department of the Interior (USDOI) Bureau of Land Management (BLM) Vernal Field Office (VFO) to develop oil and natural gas resources within the Monument Butte, Red Wash and West Tavaputs Exploration and Development Areas. The project area is located within Uintah and Duchesne Counties, Utah and consists of approximately 187 sections located in Township 9 South, Ranges 18 and 19 East; Township 10 South, Ranges 14, 15, 16, 17 and 18 East; and Township 11 South, Ranges 14, 15, 16, 17, 18 and 19 East (Map 1).

Gasco operates the majority of the mineral lease rights underlying both the public and private lands in the project area. The project area encompasses approximately 206,826 acres predominantly in the West Tavaputs Exploration and Development Area with some overlap into the Monument Butte–Red Wash Exploration and Development Area of the Diamond Mountain Planning Area of the VFO. The project area includes lands within the restored exterior boundary of the Ute Indian Reservation, but no lands administered by the Tribe or by the Bureau of Indian Affairs. Targeted geologic strata lie in the Wasatch, Mesaverde, Blackhawk, Mancos, Dakota, and Green River formations, approximately 5,000–20,000 feet below the earth's surface.

1.1 Project Description

The Gasco Energy Inc. Uinta Basin Natural Gas Development Project (GASCO) Project Area is located 20 miles south-southwest of Roosevelt, Utah and covers 206,826 acres in an existing oil and gas producing region located in Duchesne and Uintah Counties, Utah. Surface ownership in the project area is 86% federal (managed by the Bureau of Land Management [BLM]), 12% State of Utah (managed by State of Utah School and Institutional Trust Lands Administration [SITLA]), and 2% private.

The GASCO Project Area currently contains active producing wells, with accompanying production related facilities, roads, and pipelines. Additional wells are proposed for development and are being considered under the Wilkin Ridge Environmental assessment (UT-080-2006-478).

Proposed wells would be drilled to recover gas reserves from the Wasatch, Mesa Verde, Blackhawk, Mancos, Dakota, and Green River Formations in the GASCO Project Area. The spacing of the wells will vary according to the geologic characteristics of the formation being developed; the densest spacing expected is one well pad per 40 acres.

The primary components of the Proposed Action that were utilized for the development of a project specific emissions inventory for this ozone assessment were based upon an updated development schedule developed by Gasco in April 2010. The Proposed Action primary components are as follows:

Up to 1,491 natural gas wells over a 15 year development period, 45 year life of project (LOP);

Up to 10 drilling rigs operating year round;

30 evaporative ponds with a total of 2,700-hp of electrical generation; and

Approximately 21,325 horsepower of compression would be added to the existing system, for a total of 27,940 horsepower (hp) within the Project Area.

Table 1-1 shows the summary of the emissions inventory for the Proposed Action.

Under the Proposed Action, the rate of development for new wells would increase gradually from project initiation until the year 2015 when the maximum proposed development rate is projected to be realized. It is anticipated that the maximum development rate of 120 new wells per year would be sustained between the years 2015 and 2018. After 2018 the planned rate of development is projected to decrease until full project development is accomplished in about the year 2015.

Emissions to the atmosphere from the proposed project would include the following criteria pollutants and precursors: nitrogen oxides (NO_x), particulates (PM_{10} and $PM_{2.5}$), Volatile Organic Compounds (VOC), and sulfur dioxide (SO_2). These pollutants would be emitted from the following activities and sources:

Well pad and road construction: equipment producing fugitive dust while moving and leveling earth, vehicles generating fugitive dust on access roads;

Drilling: vehicles generating fugitive dust on access roads, and drill rig engine exhaust;

Completion: vehicles generating fugitive dust on access roads, frac pump engine and generator emissions, and completion venting emissions;

Vehicle tailpipe emissions associated with all development phases;

Well production operations: three-phase separator emissions, flashing and breathing emissions from a condensate tank, fugitive dust and tailpipe emissions from pumpers and trucks transporting produced condensate and water from storage tanks;

Central production facility: compressor engines emissions, central glycol dehydration unit emissions, flare emissions for control of central facility VOC emissions, central flashing and breathing emissions from condensate tanks, and emissions associated with loading natural gas liquids (NGL) into trucks; and

Water Evaporation Facility: generator engine emissions and fugitive dust and tailpipe emissions from water trucks delivering produced water.

To reduce the emission of ozone forming precursors (NO_X and VOC) GASCO has committed to implement the following Applicant Committed Environmental Protection Measures (ACEPMs):

1. The use of Tier II or better diesel drill rig engines to reduce NO_X emissions;
2. RMP compliant NO_X emission limitations of 1.0 g/hp-hr for engines rated greater than 300 hp and 2.0 g/hp-hr for engines rated at 300 hp or less.
3. The installation of low-bleed pneumatic controls, where technically feasible, on all new separators to reduce potential VOC emissions;
4. To reduce current VOC emissions all existing high-bleed pneumatic controls within the project area will be replaced or retrofitted with low-bleed units where technical feasible;
5. The use of solar-powered chemical pumps (i.e. Methanol pumps) in place of VOC emitting pneumatic pumps at new facilities;

6. The use of centralized compression facilities (no well site compression) to minimize potential NO_X emissions;
7. The use of centralized dehydration, (no well site dehydration) to minimize potential VOC emissions;
8. The control of central facility stock tanks and glycol dehydrators to reduce potential VOC emissions by at least 95%.

The above ACEPMs would result in the reduction of 647 tons per year NO_X and 8,273 tons per year of VOC assuming the implementation of the Proposed Action. Larger or smaller emission reductions would occur as a result of the ACEPMs if other alternatives other than the Proposed Action were to be implemented.

This ozone impact analysis considered the emissions from the Proposed Action with and without applicant committed measures to reduce ozone precursor emissions.

Oil and Gas Exploration and Production Emission Sources

Presentation for the
Air Quality Control Commission Retreat

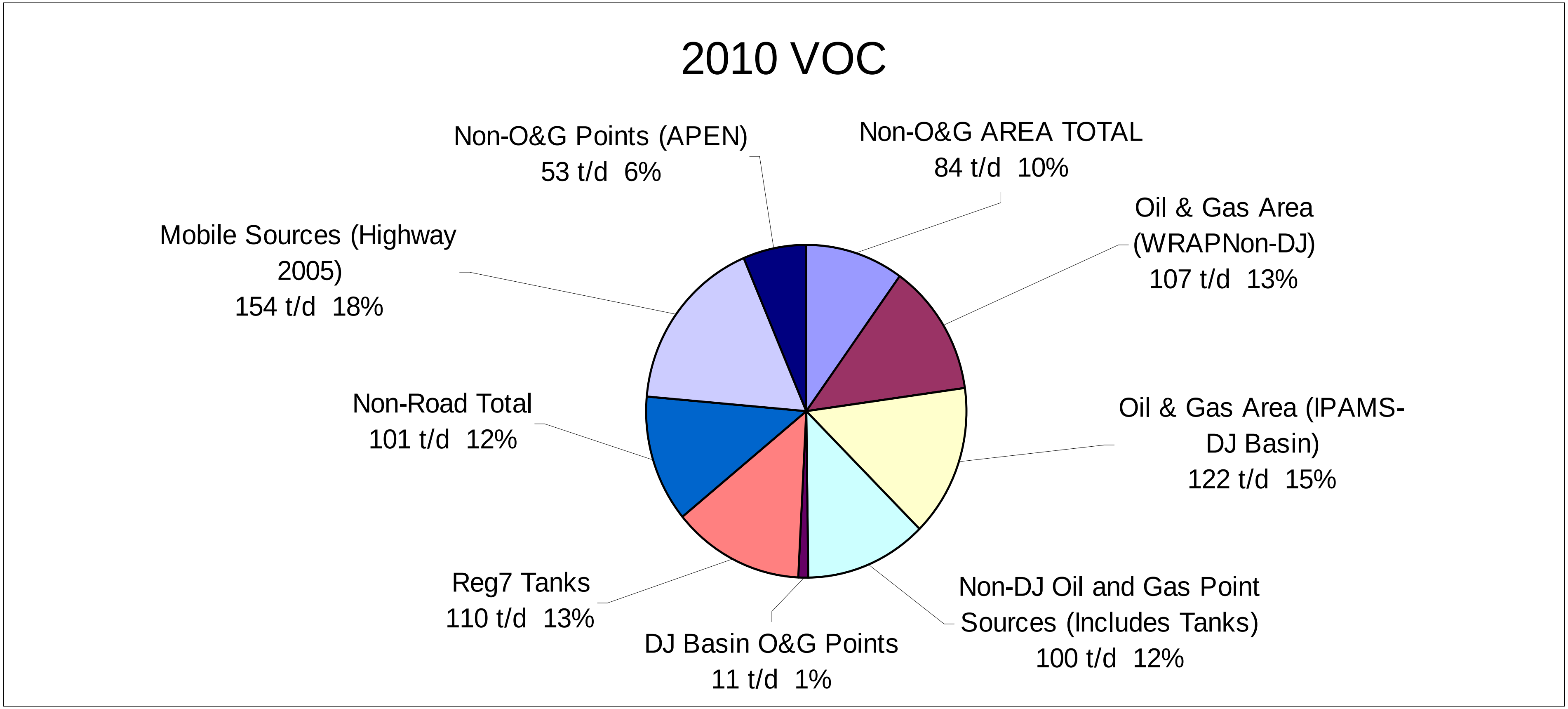
May 15, 2008

Air Pollution Control Division

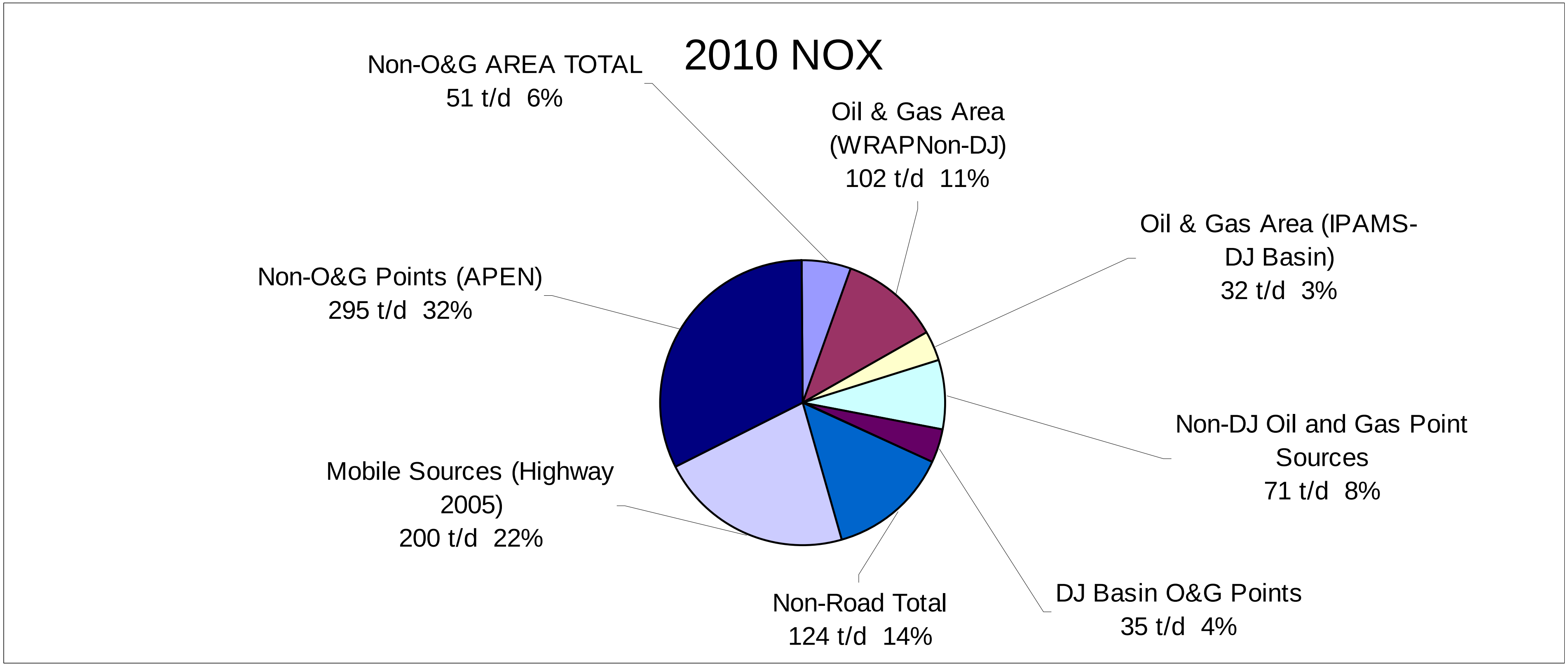
Approach to Statewide Oil and Gas Control Strategy Development

- Oil and gas is the largest VOC source category on the State
- Oil and gas development is rapid and projected to significantly expand – especially in western Colorado
- Strategies are being developed to control the growth in VOC and NOx emissions from O&G
  - Pre-emptive – “keep clean areas clean”
  - Help prevent ozone nonattainment
  - Improve visibility

Statewide
VOC Emissions – 2010
(4% increase since 2006)



Statewide
NOx Emissions – 2010
(8% increase since 2006)



Approach to Statewide Oil and Gas Control Strategy Development

- All current regulatory programs remain in place
- Categorical Exemptions - Eliminate for Significant Oil and Gas Categories - New Sources (VOCs)
- Pneumatics – New, Modified (VOCs)
- Condensate Tanks – New, Modified (VOCs)
- Drill Rigs – New and Existing (NOx, PM)
- Existing Engines – Retrofit (VOCs, CO, NOx

Elimination of Categorical Exemptions for Oil and Gas Sources

- Crude oil truck loading equipment
- Oil/gas production wastewater tanks
- Stationary Internal Combustion Engines meeting horsepower and hours of operation restrictions
- Condensate tanks with production 730 BBL/year or less
- Fuel burning equipment (includes heater treaters, separators, and dehydrator reboilers)
- Petroleum industry flares less than 5 tons per year (tpy) emissions
- Storage of butane, propane, LPG
- Crude oil storage tanks
- Surface water storage impoundment
- Internal combustion engines on drill rigs
- Venting of natural gas lines for safety purposes (for APEN purposes only)
- Oil and gas production activities including: well drilling, workovers and completions (for APEN purposes only)

CONSERVATION COMMISSION

COLORADO

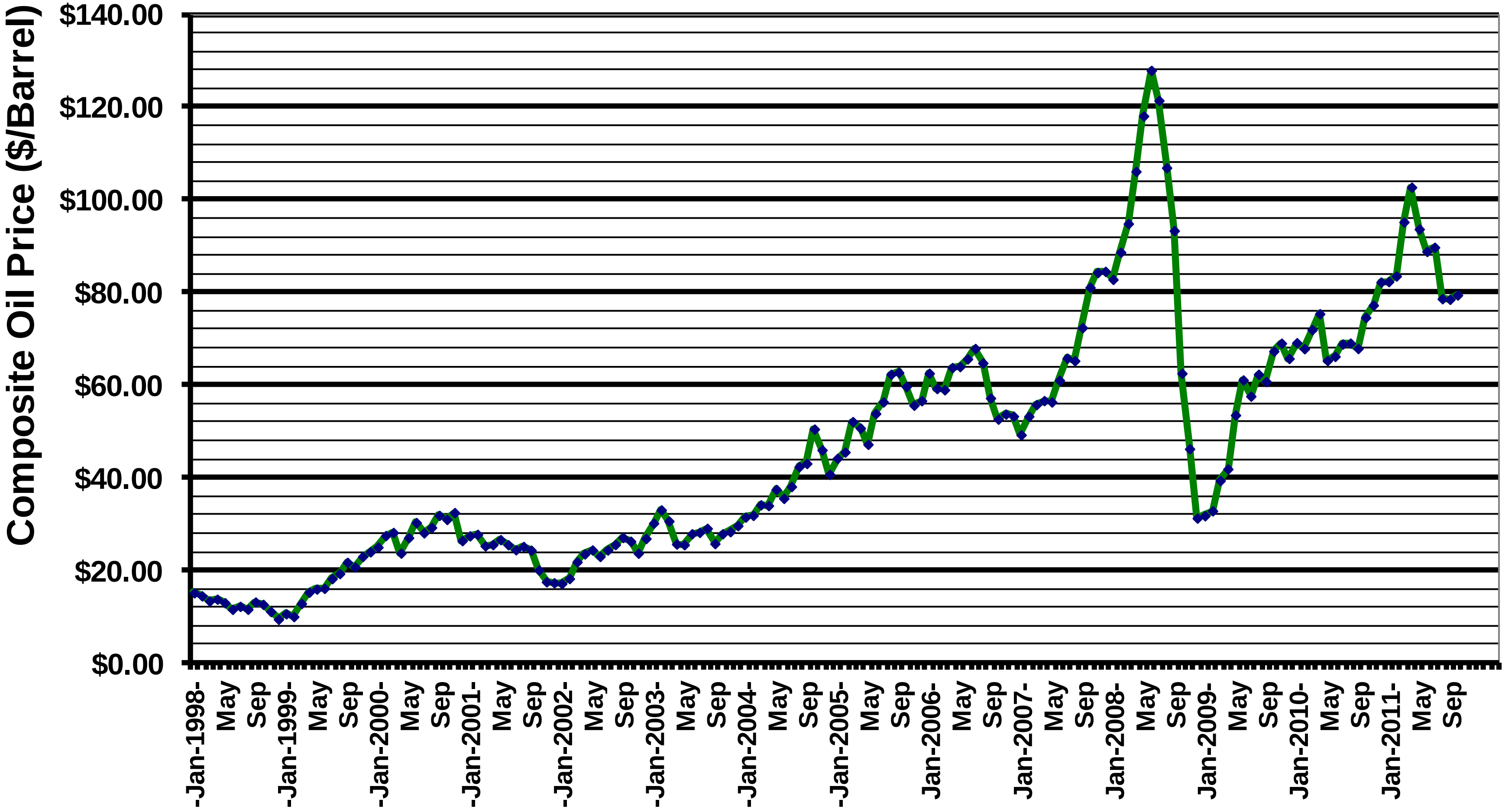
WEEKLY & MONTHLY

OIL & GAS STATISTICS

11-07-11 – visit our website: www.colorado.gov/cogcc

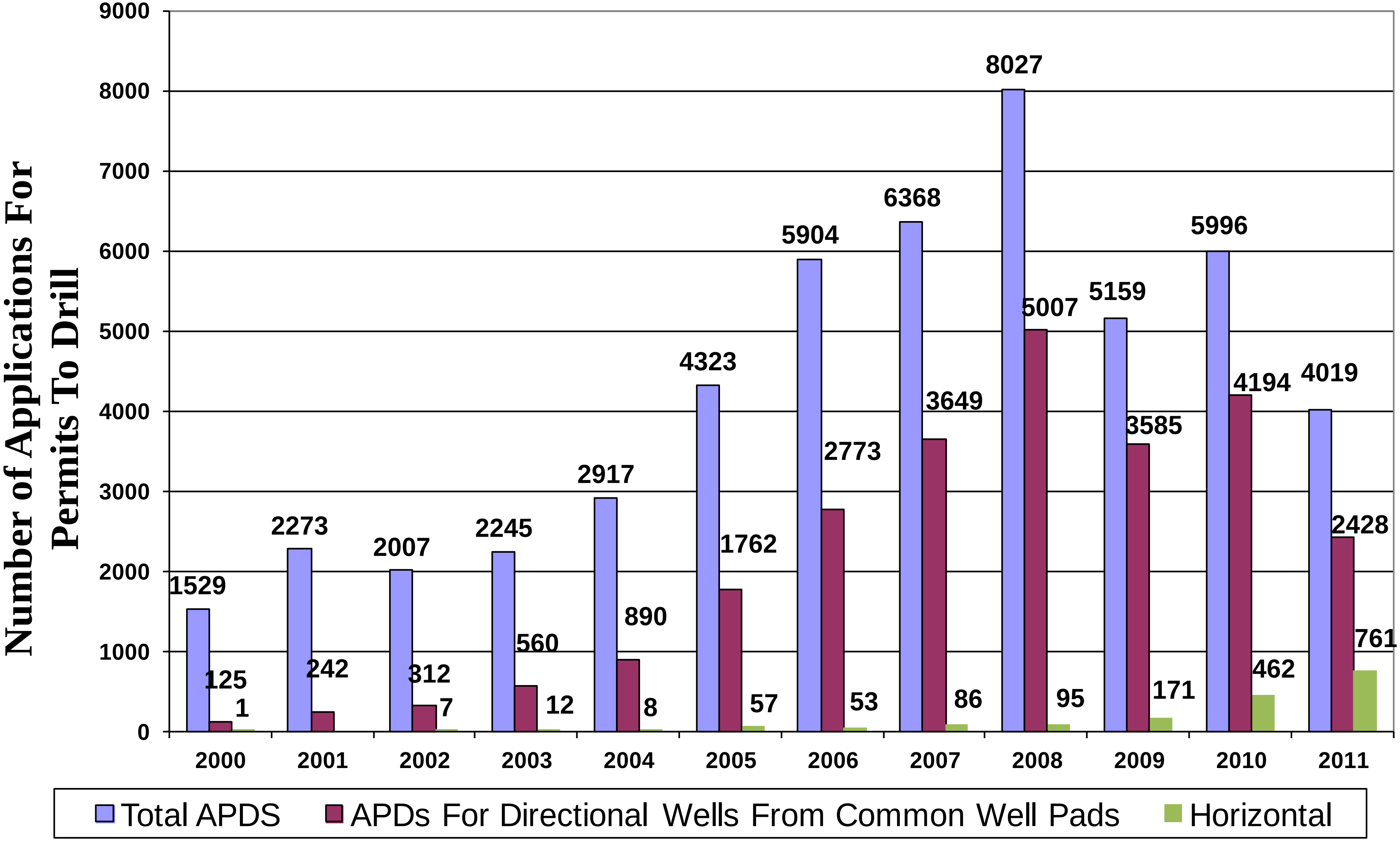
Colorado Monthly Composite Oil Price

(35% Chevron NW, 5% Equiva SW, 40% Valero NE, 20% Valero SE : ~= WTI+$0.70) 11-07-11

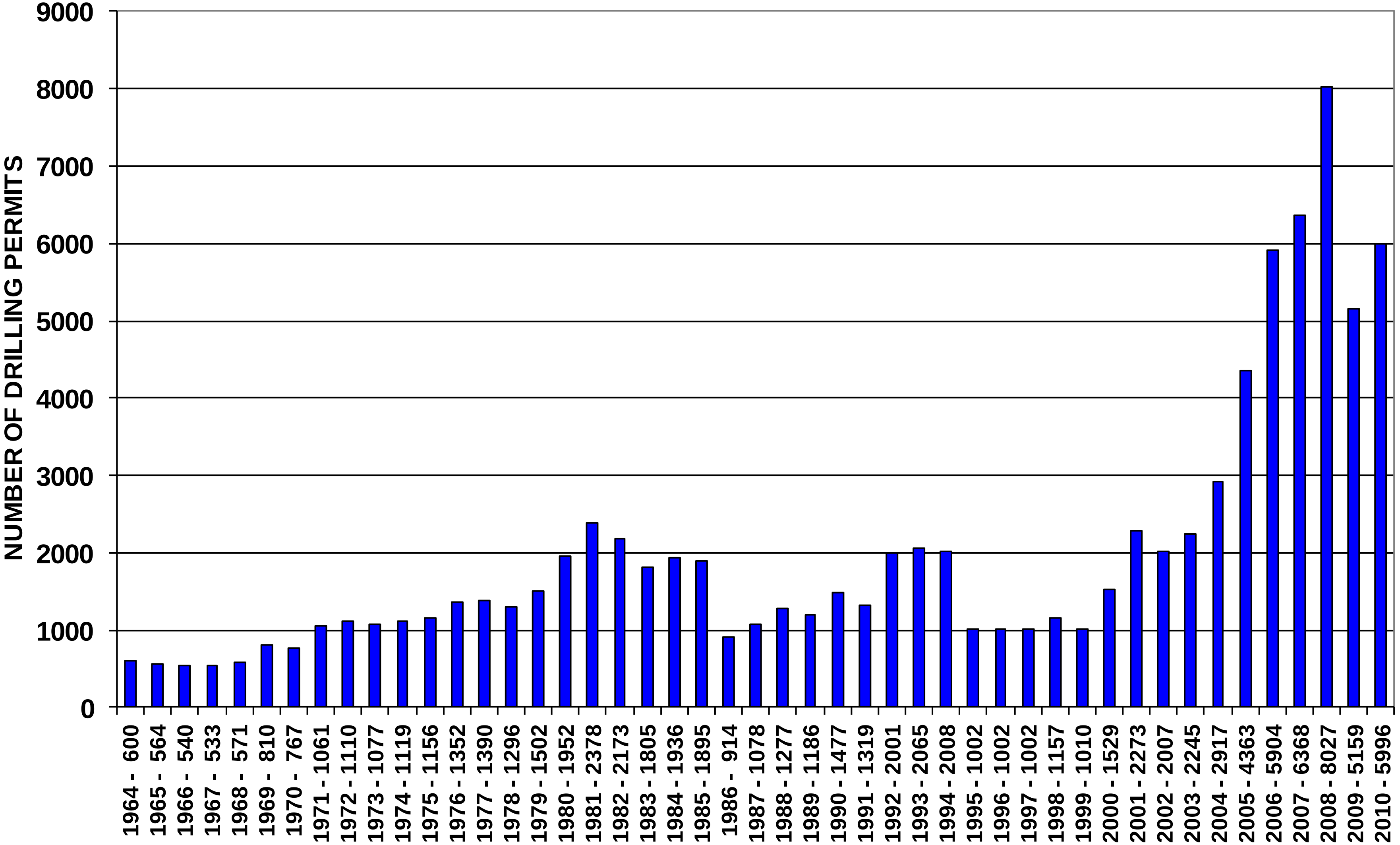


Number of Oil and Gas Well Permits For Wells Drilled Directionally & Horizontally From Common Well Pads in Colorado

11-07-11

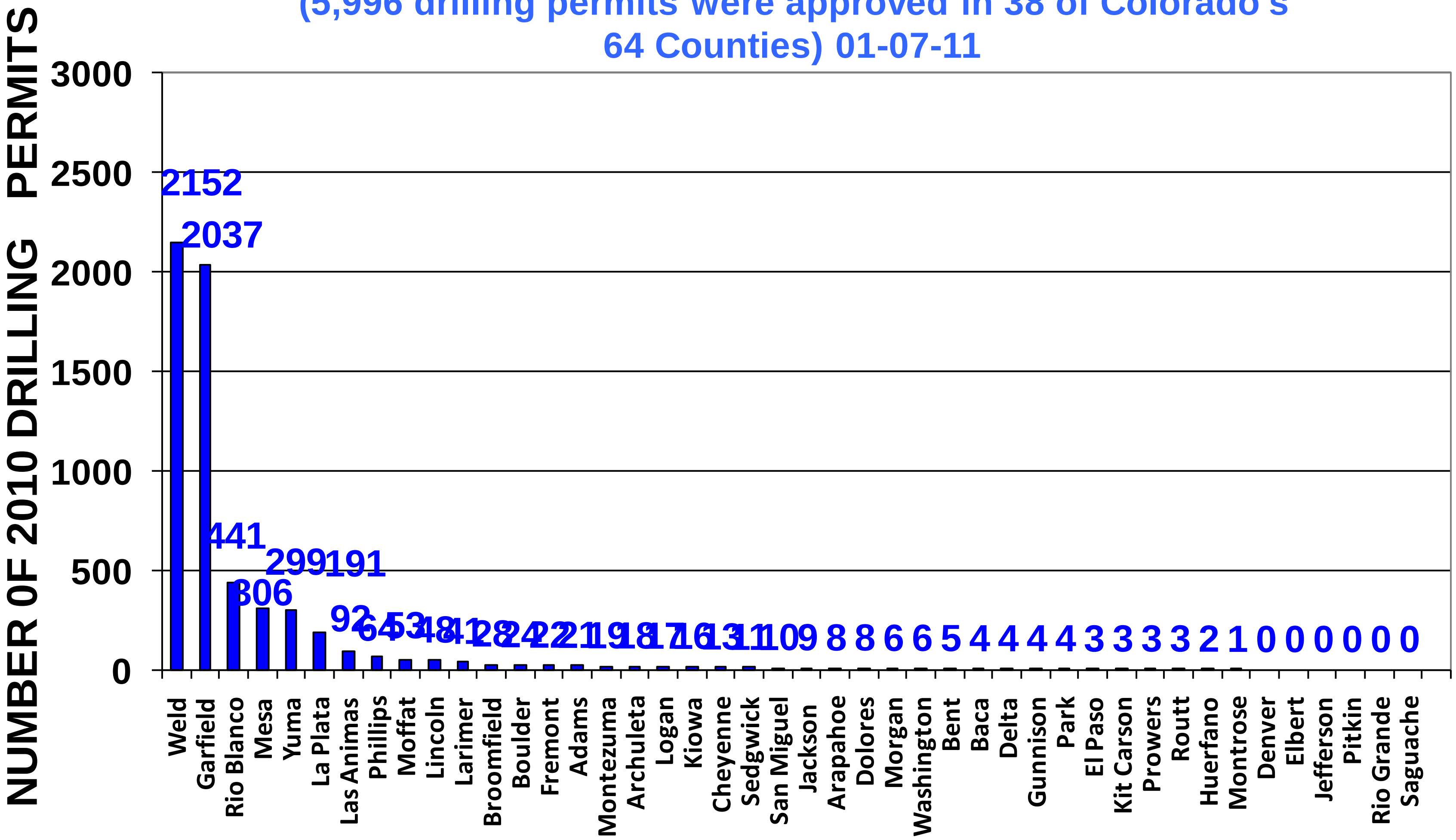


HISTORIC ANNUAL COLORADO DRILLING PERMITS 11-07-11



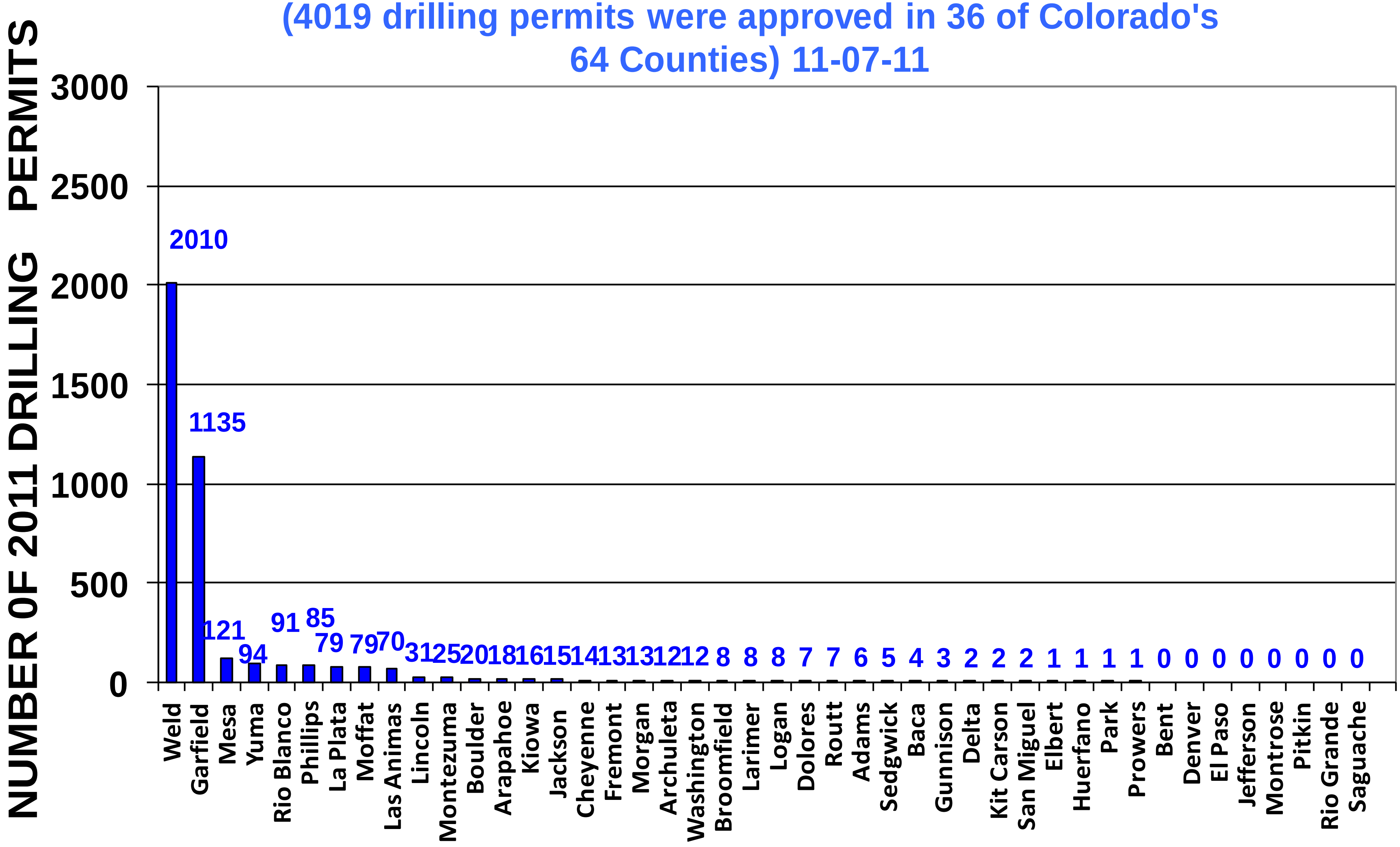
NUMBER OF 2010 DRILLING PERMITS, ALL COLORADO COUNTIES

(5,996 drilling permits were approved in 38 of Colorado's 64 Counties) 01-07-11



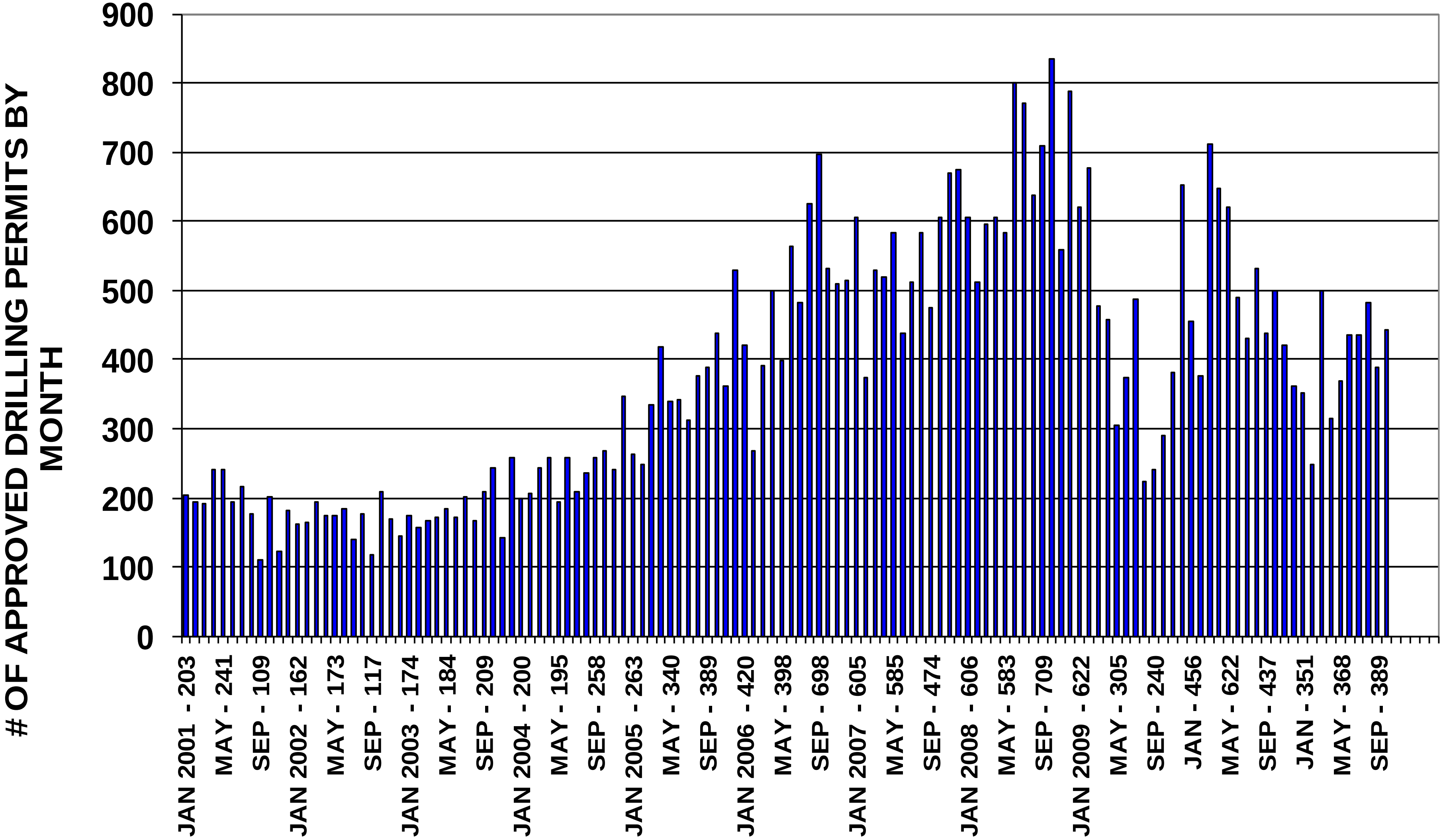
NUMBER OF 2011 DRILLING PERMITS, ALL COLORADO COUNTIES

(4019 drilling permits were approved in 36 of Colorado's 64 Counties) 11-07-11



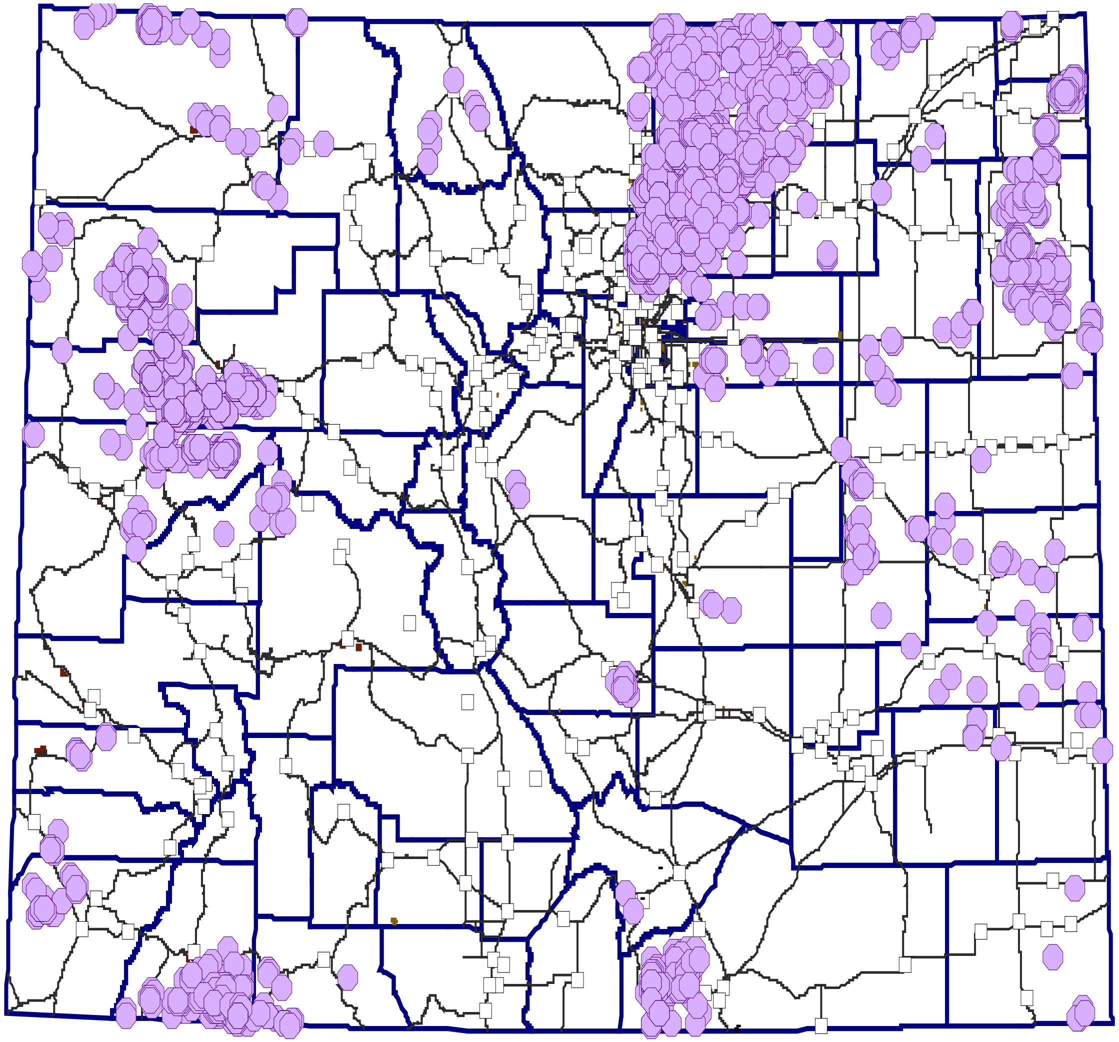
COLORADO MONTHLY APPROVED DRILLING PERMITS

as of 11-07-11



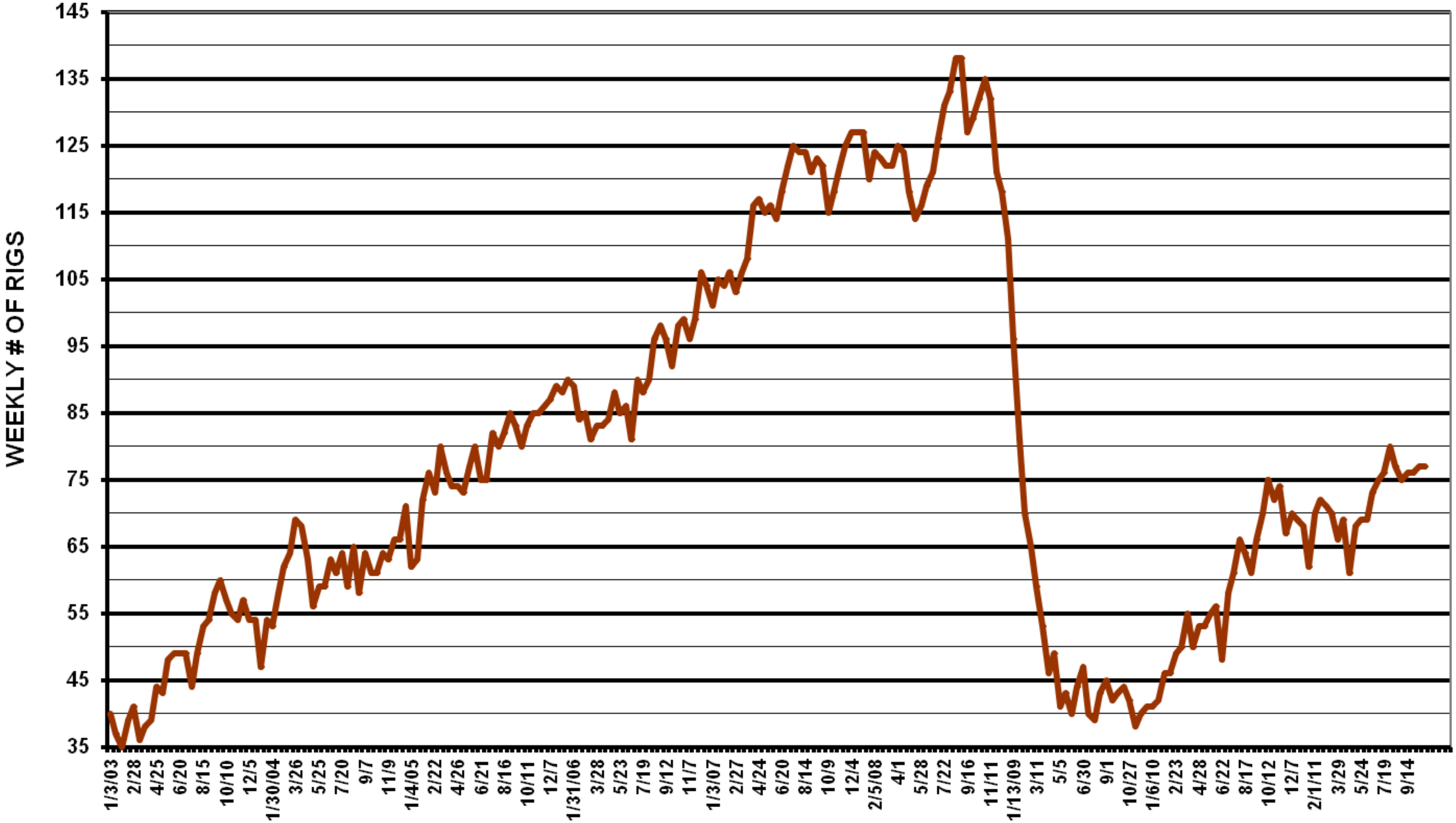
RECENT COLORADO OIL AND GAS WELL PERMITS

11-07-11



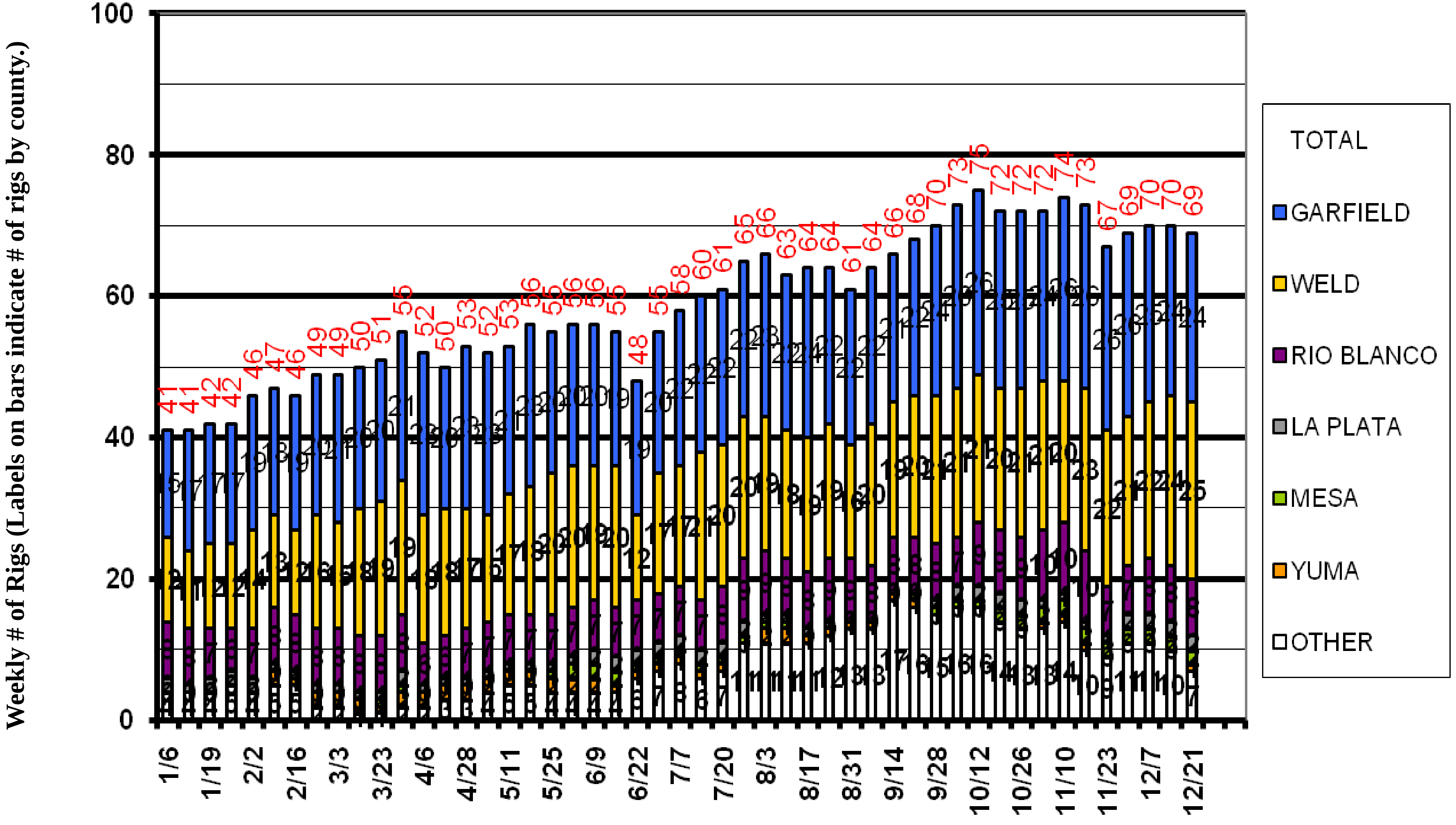
TOTAL DRILLING RIGS RUNNING IN COLORADO EVERY OTHER WEEK IN 2003-2011

(Based on Data in: through 4/30/03, PI/Dwights Drilling Wire -- after 4/30/03, Anderson Reports
Weekly Rig Status Report)



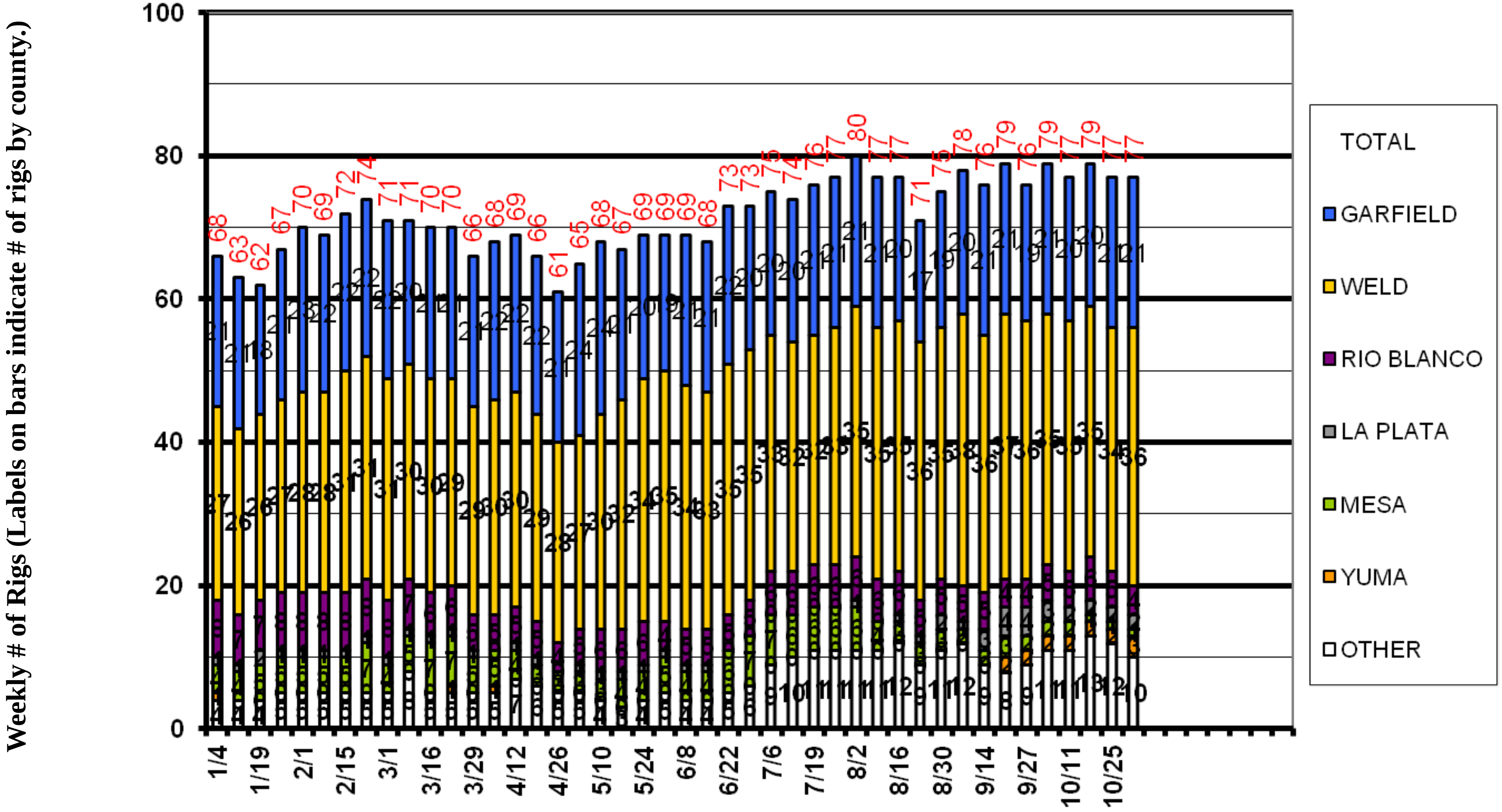
DRILLING RIGS RUNNING IN COLORADO BY COUNTY EACH WEEK IN 2010

(Based on Data in Anderson Reports Weekly Rig Status Report)



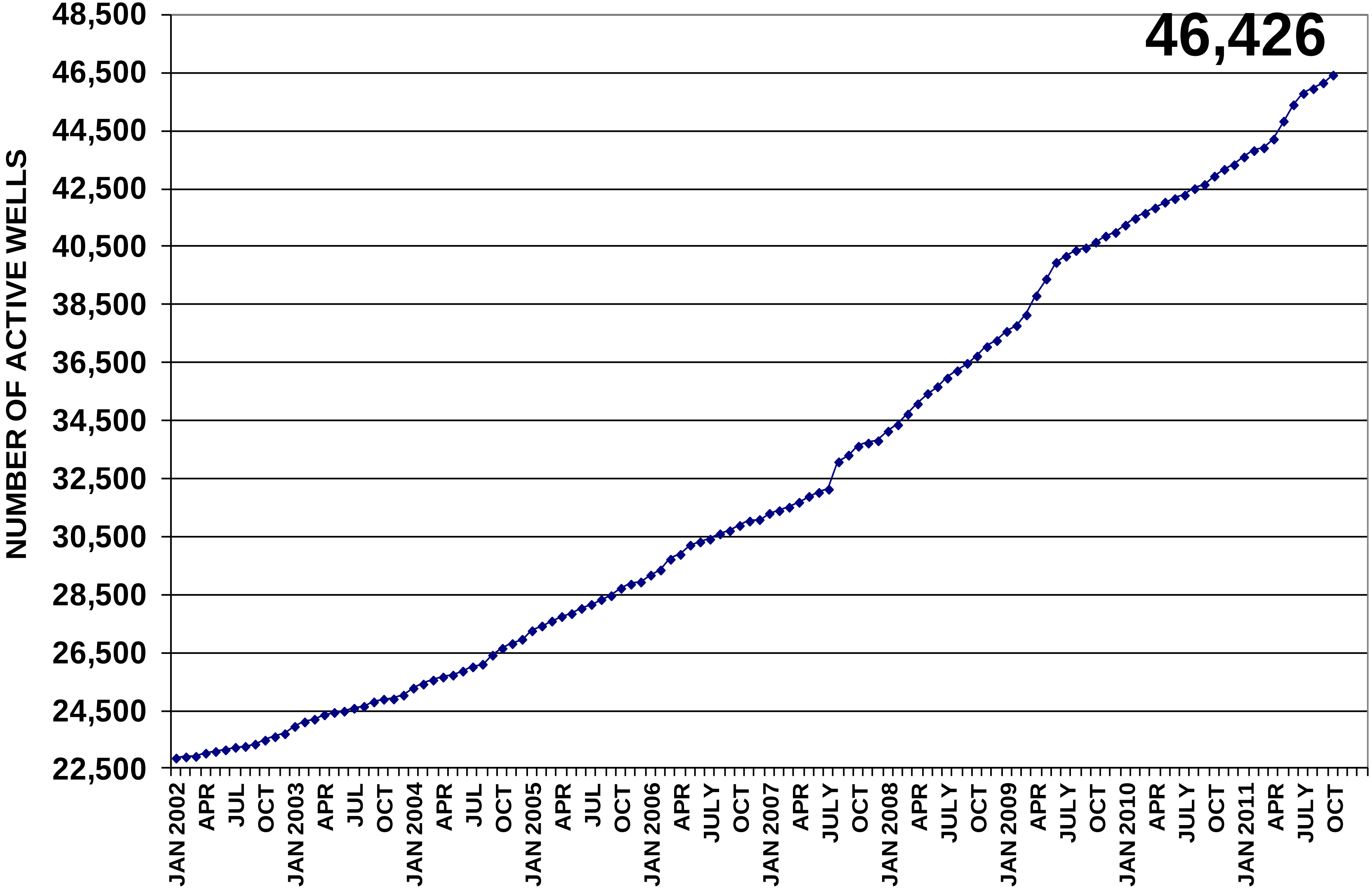
DRILLING RIGS RUNNING IN COLORADO BY COUNTY EACH WEEK IN 2011

(Based on Data in Anderson Reports Weekly Rig Status Report)



COLORADO MONTHLY ACTIVE WELL COUNT

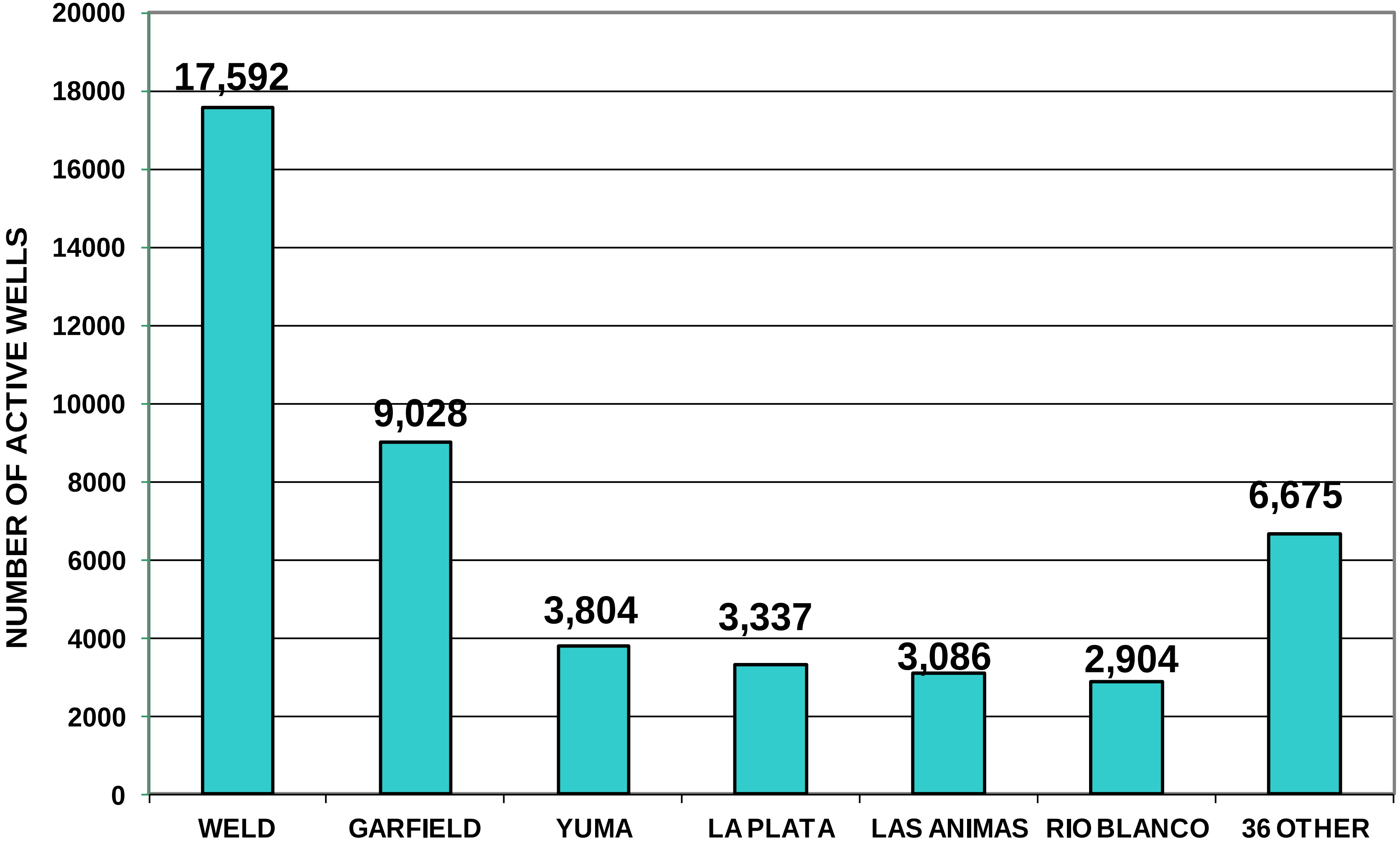
11-07-11



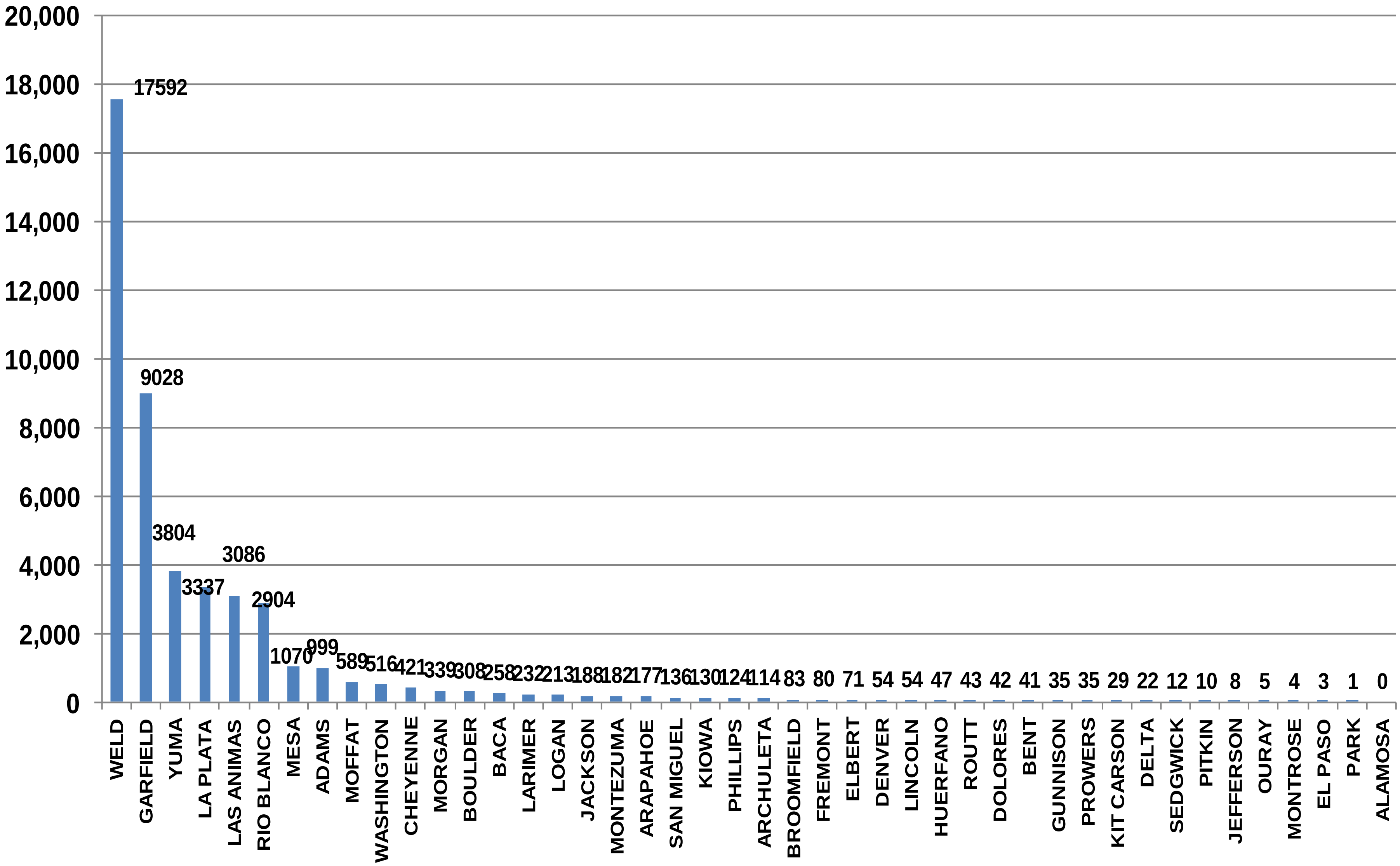
NUMBER OF ACTIVE COLORADO OIL & GAS WELLS BY COUNTY

86.0% of Colorado's 46,426 active wells are located in these 6 counties

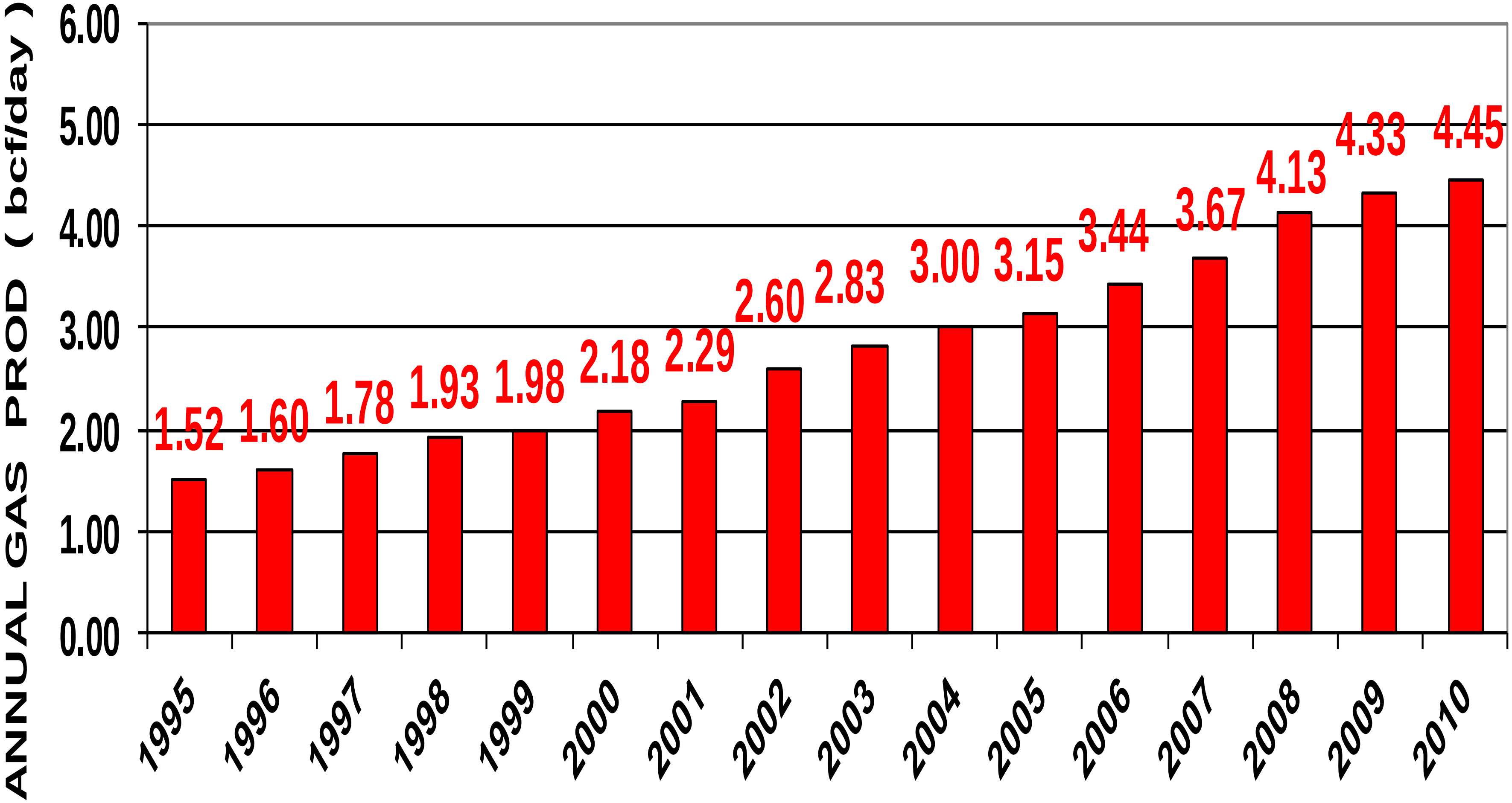
(11-07-11)



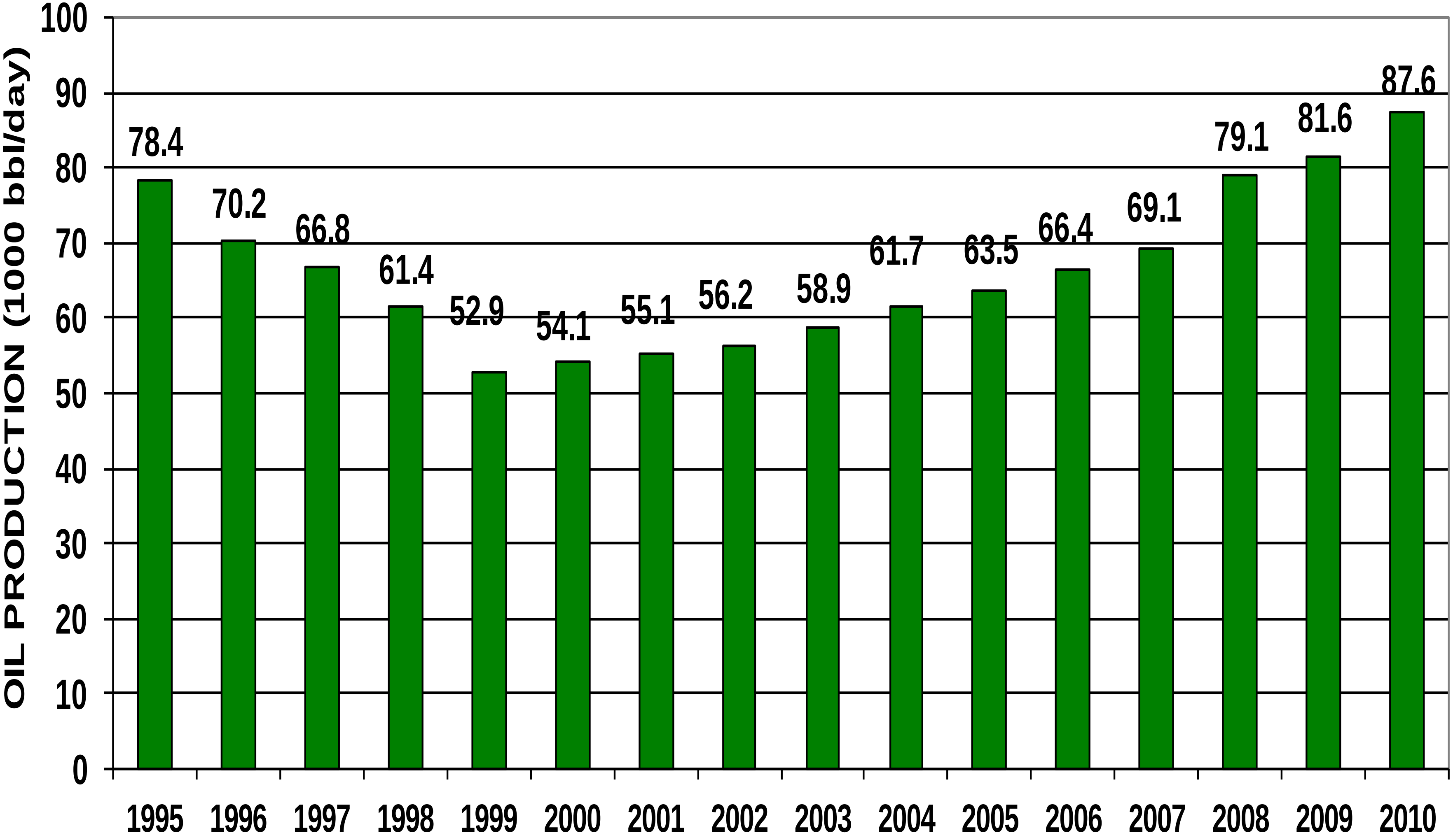
ACTIVE OIL & GAS WELLS – ALL COLORADO COUNTIES
11-07-11



COLORADO NATURAL GAS PRODUCTION
1995-2010
BILLION CUBIC FEET OF GAS PER DAY 11-07-11

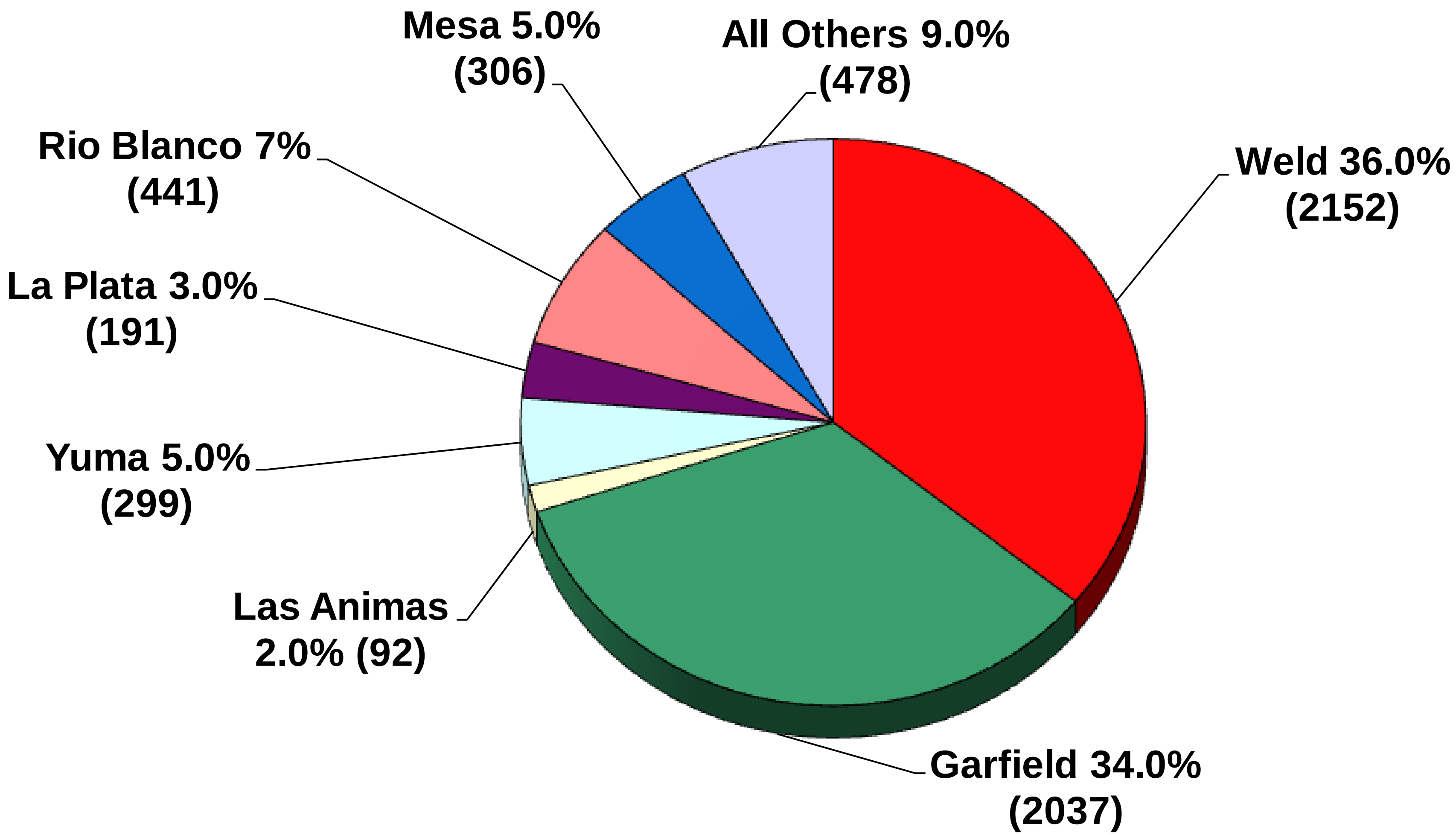


COLORADO OIL PRODUCTION 1995-2010
THOUSAND BARRELS PER DAY 11-07-11



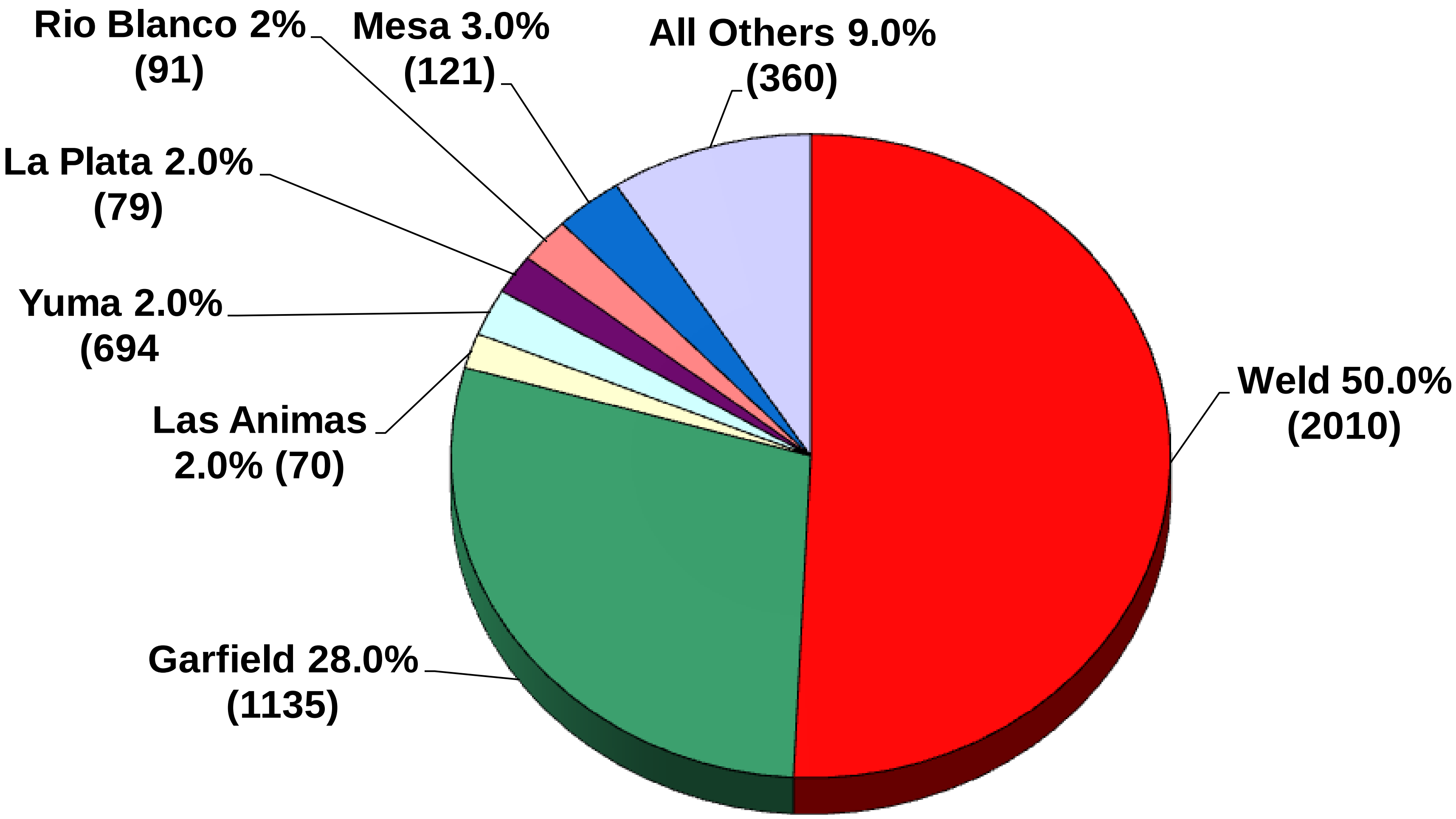
COLORADO OIL AND GAS 2010 DRILLING PERMITS BY COUNTY

as of 01-07-11

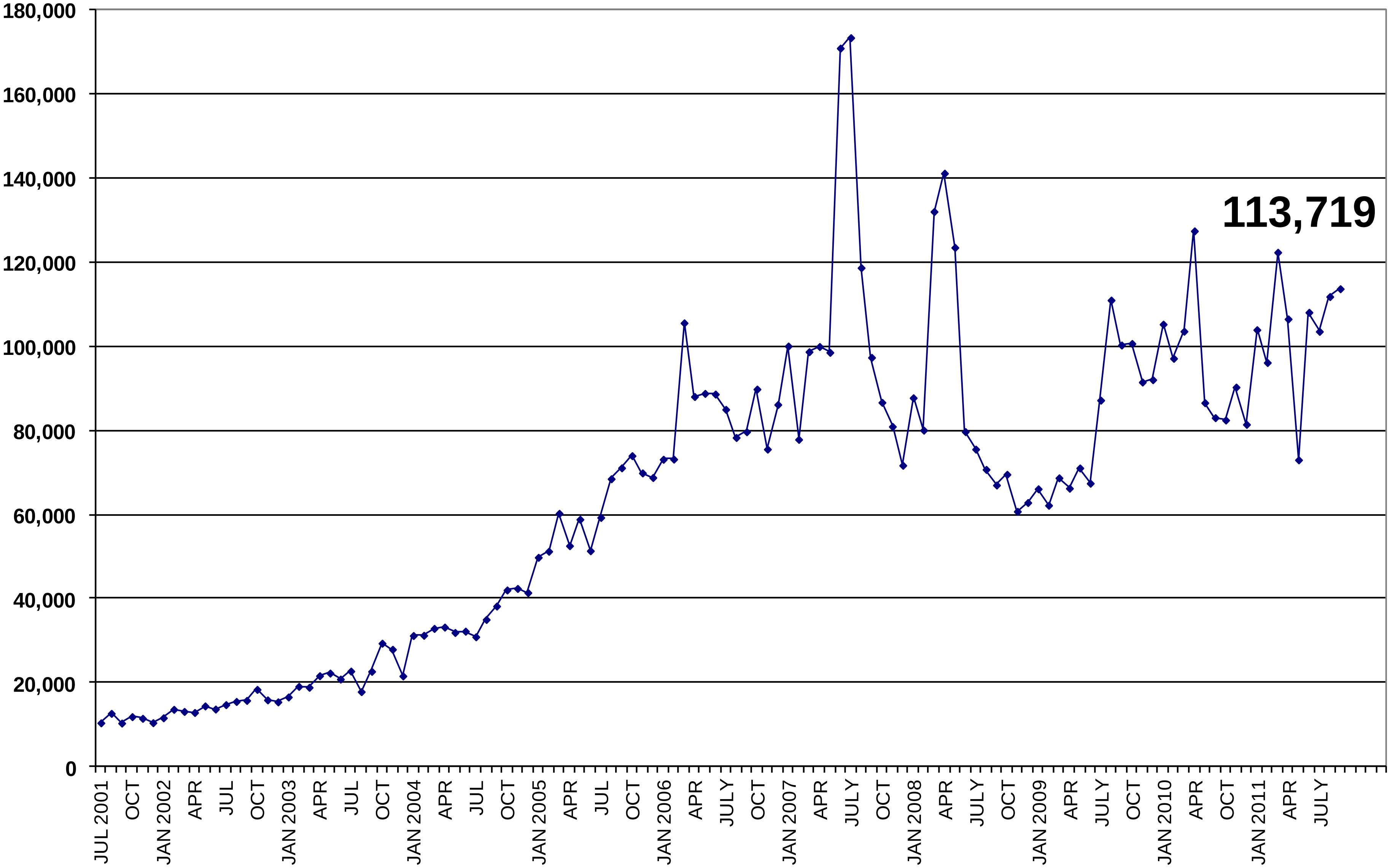


COLORADO OIL AND GAS 2011 DRILLING PERMITS BY COUNTY

as of 11-07-11



COLORADO MONTHLY COGCC WEBSITE VISITS
10-07-11



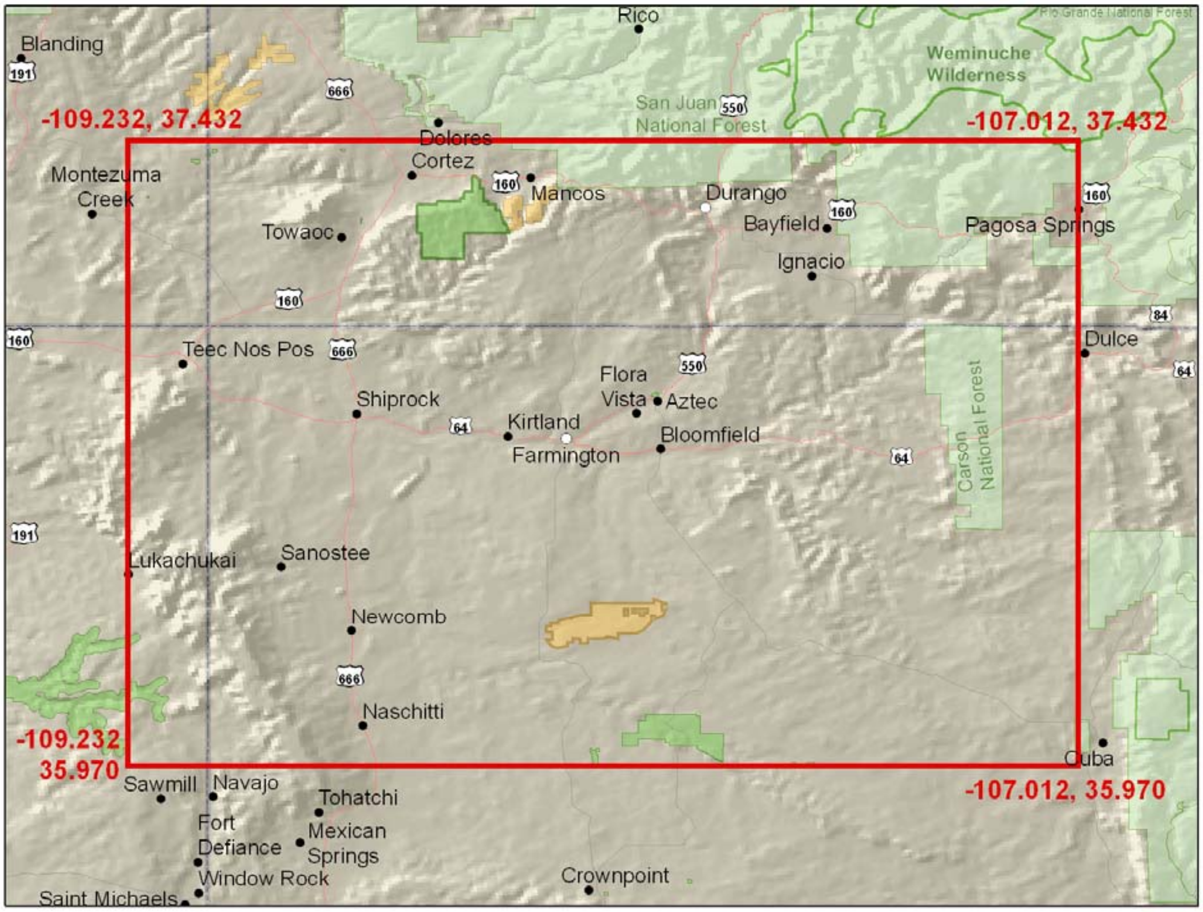
Colorado Oil & Gas Conservation Commission Statutory Requirements

*Please note that information within parentheses is additional background information and not a statutory requirement

Commissioner (Officer)	**2 Executive Directors (ex-officio voting members)** (Current Employment)	**2 West of Continental Divide** (Resident County)	**3 with Substantial Oil & Gas Experience** (Employed by Oil & Gas Industry) (Current Employment)	**2 Out of 3 Must Have a College Degree in Petroleum Geology or Petroleum Engineering**	**1 Local Government Official** (Current Employment)	**1 with Substantial Environmental or Wildlife Protection Experience** (Current Employment)	**1 with Substantial Soil Conservation or Reclamation Experience** (Current Employment)	**1 engaged in Agricultural Production and a Royalty Owner** (Current Employment)	**Maximum of 4 from Same Political Party (excluding Executive Directors)**	**Current Term Expires**
Richard Alward		**X** (Mesa)					**X** (Ecologist)		D	7/1/2015
Tom Compton Chairman		**X** (La Plata)						**X** (Rancher)	R	7/1/2015
Tommy Holton		(Fort Lupton)			**X**				R	7/1/2015
John Benton		(Littleton)	**X**	**X**					R	7/1/2015
W. Perry Pearce Vice Chair		(Denver)	**X**						D	7/1/2015
DeAnn Craig		(Denver)	**X**	**X**					R	7/1/2012
Andrew Spielman		(Denver)	**X**			**X**			D	7/1/2015
Mike King	**X** (Department of Natural Resources)	(Denver)								
Chris Urbina	**X** (Department of Public Health and Environment)	(Denver)								

Commissioner requrements are set by statute in the Oil and Gas Conservation Act at §34-60-104 (2) (a)(1), C.R.S. (Current as of 09-19-2011)

Four Corners Air Quality Task Force
Report of Mitigation Options



November 1, 2007

The report is a compilation of mitigation options
drafted by members of the Four Corners Air Quality Task Force.
This is not a document to be endorsed by the agencies involved,
but rather, a compendium of options for consideration
following completion of the Task Force's work in November 2007.

Four Corners Air Quality Task Force Members List

Task Force members were those individuals who regularly attended quarterly meetings, participated in one or more work groups, and who assisted in drafting and providing comments on the mitigation option papers and other sections of the Task Force Report.

Erik Aaboe	New Mexico Environment Department	Santa Fe, NM
Zachariah Adelman	Carolina Environmental Program	Chapel Hill, NC
Scott Archer	USDI Bureau of Land Management	Denver, CO
Roger Armstrong	Twin Stars Ltd.	Farmington, NM
Mary Lou Asbury	League of Women Voters (Cortez, Montezuma)	Cortez, CO
Cindy Beeler	US Environmental Protection Agency, Region 8	Denver, CO
Brittany Benko	BP America	Durango, CO
Andy Berger	New Mexico Environment Department	Santa Fe, NM
Bruce Beynon	Chevron	Houston, TX
Michael Brand	Cummins	Columbus, IN
Kevin Briggs	Colorado Dept. of Public Health & Environment	Denver, CO
David Brown	BP America	Denver, CO
Marilyn Brown	League of Women Voters of La Plata County	Durango, CO
Walt Brown	US Forest Service/BLM	Durango, CO
Fran King Brown	AKA Energy Group, LLC (SUIT)	Durango, CO
Greg Crabtree	Envirotech, Inc.	Farmington, NM
Jim Cue	Caterpillar, Inc.	Houston, TX
Mark Dalton	Samson Resources Company	Tulsa, OK
Carl Daly	US Environmental Protection Agency, Region 8	Denver, CO
Chris Dann	Colorado Dept. of Public Health & Environment	Denver, CO
Joseph Delwiche	US Environmental Protection Agency, Region 8	Denver, CO
Kris Dixon	Concerned Citizen	Farmington, NM
Ryan Dupnick	Compliance Controls, LLC	Houston, TX
Mike Eisenfeld	Tetra Tech Inc. / San Juan Citizens Alliance	Farmington, NM
Mike Farley	Public Service Company of New Mexico	Albuquerque, NM
Joel Farrell	USDI Bureau of Land Management	Farmington, NM
Kerri Fieldler	US Environmental Protection Agency, Region 8	Denver, CO
Patrick Flynn	Resolute Natural Resources Company	Denver, CO
Erich Fowler	Denver University	Denver, CO
Bruce Gantner	ConocoPhillips	Farmington, NM
Mike George	National Park Service	Austin, TX
Richard Goebel	Archuleta County	Pagosa Springs, CO
Kevin Golden	US Environmental Protection Agency, Region 8	Denver, CO
Bob Gonzalez	Caterpillar, Inc.	Houston, TX
Christi Gordon	USDA Forest Service, Region 3	Albuquerque, NM
Richard Grimes	Arizona Public Service Company	Fruitland, NM
Doug Henderer	Buys & Associates, Inc.	Littleton, CO
Terry Hertel	New Mexico Environment Department	Santa Fe, NM
Cheryl Heying	Utah Department of Environmental Quality	Salt Lake City, UT
Jeanne Hoadley	USDA Forest Service	Santa Fe, NM
Bill Hochheiser	US Department of Energy	Washington, DC
Katherine Holt	La Plata Vision 2030 - Environmental Stewardship	Durango, CO
Eric Janes	Retired Federal Employee, USDI	Mancos, CO
Susan Johnson	National Park Service	Denver, CO
Mark Jones	New Mexico Environment Department	Farmington, NM
Bob Jorgenson	Colorado Dept. of Public Health & Environment	Denver, CO
Josh Joswick	San Juan Citizens Alliance	Durango, CO
Kyle Kerr	Envirotech, Inc.	Farmington, NM
Chad King	Giant Bloomfield Refinery	Bloomfield, NM
Myke Lane	Williams	Aztec, NM

Doug Latimer	US Environmental Protection Agency, Region 8	Denver, CO
Wilson Laughter	Navajo Nation Environmental Protection Agency	Fort Defiance, AZ
Michael Lazaro	Argonne National Laboratory	Argonne, IL
Cindy Liverance	American Lung Association	Denver, CO
Kim Bruce Livo	Colorado Dept. of Public Health & Environment	Denver, CO
Ran Macdonald	Utah Department of Environmental Quality	Salt Lake City, UT
Jen Mattox	Colorado Dept. of Public Health & Environment	Denver, CO
Mark McMillan	Colorado Dept. of Public Health & Environment	Denver, CO
Shirley McNall	Concerned Citizen	Aztec, NM
Joe Miller	Southern Ute Indian Tribe (Consultant)	Arvada, CO
Ray Mohr	Colorado Dept. of Public Health & Environment	Denver, CO
Theodore Mueller	Retired Professor, Adams State University	Aztec, NM
Michael Nelson	ConocoPhillips	Houston, TX
Craig Nicholls	USDI Bureau of Land Management	Denver, CO
Jeremy Nichols	Rocky Mountain Clean Air Action	Denver, CO
Koren Nydick	Mountain Studies Institute	Durango, CO
Sylvia Oliva	National Park Service	Mesa Verde, CO
Ted Orf	Orf & Orf	Denver, CO
Casey Osborn	EMIT Technologies	Sheridan, WY
Kelly Palmer	US Forest Service / BLM, San Juan National Forest	Durango, CO
Bill Papich	USDI Bureau of Land Management	Farmington, NM
Margie Perkins	Colorado Dept. of Public Health & Environment	Denver, CO
Gordon Pierce	Colorado Dept. of Public Health & Environment	Denver, CO
Debby Potter	USDA Forest Service, Region 3	Albuquerque, NM
John Prather	Devon Energy Corporation	Navajo Dam, NM
Dan Randolph	San Juan Citizens Alliance	Durango, CO
Jan Rees	Concerned Citizen	Bloomfield, NM
Rebecca Reynolds	RRC Inc., Task Force Project Manager	Brighton, CO
Roxanne Roberts	Williams	Tulsa, OK
Bud Rolofson	USDA Forest Service, Region 4	Golden, CO
Curtis Rueter	Noble Energy, Inc.	Denver, CO
Dave Ruger	Honeywell	Farmington, NM
George San Miguel	Mesa Verde National Park	Mesa Verde, CO
Mark Sather	US Environmental Protection Agency, Region 6	Dallas, TX
Randy Schmaltz	Giant Bloomfield Refinery	Bloomfield, NM
David Schneck	San Miguel Co. Environmental Health Dept.	Telluride, CO
Ted Schooley	New Mexico Environment Department	Santa Fe, NM
Jack Schuenemeyer	Southwest Statistical Consulting, LLC	Cortez, CO
Michael Schum	Lovelace Clinic Foundation	Albuquerque, NM
Brett Sherman	La Plata County Government	Durango, CO
Lincoln Sherman	Air Resource Specialists, Inc.	Fort Collins, CO
Mike Silverstein	Colorado Dept. of Public Health and Environment	Denver, CO
Stacey Simms	American Lung Association / Clean Cities Coalition	Greenwood Village, CO
Kellie Skelton	Energen Resources, Inc.	Farmington, NM
Reid Smith	BP America	Houston, TX
Carla Sonntag	NM Utility Shareholders Association	Albuquerque, NM
Jeff Sorkin	US Forest Service, Region 4	Golden, CO
Lisa Sumi	Oil and Gas Accountability Project	Durango, CO
Zach Tibodeau	Beaver Creek Resorts / Vail Associates	Avon, CO
Ron Truelove	Devon Energy Corporation	Oklahoma, City, OK
Rita Trujillo	New Mexico Environment Department	Santa Fe, NM
Evan Tullos	EPCO, Inc.	Farmington, NM
Mary Uhl	New Mexico Environment Department	Santa Fe, NM
Wano Urbonas	San Juan Basin Health Department	Durango, CO
Callie Vanderbilt	San Juan College	Farmington, NM
Beverly Warburton	Concerned Citizen	Pagosa Springs, CO

Sarah Jane White	Diné CARE	Shiprock, NM.
Brady Winkleman	Caterpillar, Inc.	Lafayette, IN
Dale Wirth	USDI Bureau of Land Management	Farmington, NM

Four Corners Air Quality Task Force Interested Parties List

Interested Parties were those individuals who followed the progress of the Task Force, and who may have attended one or more quarterly meetings, may have participated in work groups and may have provided comments on sections of the Task Force Report.

Reid Allan	Souder, Miller & Associates	Farmington, NM
Cindy Allen	EnCana	Denver, CO
Lee Alter	Western Governors' Association	Denver, CO
Charlene Anderson	Creative Geckos	Farmington, NM
Donald Anderson	Concerned Citizen, VLUA	Bayfield, CO
Blair Armstrong	TEPPCO - Natural Gas Services	Bloomfield, NM
Mohan Asthana	Navajo Nation Environmental Protection Agency	Fort Defiance, AZ
Amon Bar-Ilan	ENVIRON International Corporation	Novato, CA
Richard Baughman	Southern Ute Department of Energy	Ignacio, CO
David Bays	Williams	Farmington, NM
Joe Becko	Cummins Rocky Mountain	Avondale, AZ
Steve Begay	Navajo Nation; Dine Power Authority	Window Rock, AZ
Erickson Bennally	Dine Power Authority	Window Rock, AZ
Carlos Betancourth	Farmington MPO	Farmington, NM
Gail Binkly	Four Corners Free Press	Cortez, CO
Robin Blanchard	San Juan Citizens Alliance	Aztec, NM
Doug Blewitt	Representing BP	Englewood, CO
Sheila Burns	Colorado Dept. of Public Health and Environment	Denver, CO
James Chivers	Concerned Citizen	Albuquerque, NM
Hugh Church	American Lung Association of NM	Albuquerque, NM
Roger Clark	Grand Canyon Trust	Flagstaff, AZ
Cynthia Cody	US Environmental Protection Agency, Region 8	Denver, CO
Leona Conger	League of Women Voters	Durango, CO
Joe Cotie	New Mexico Environment Department	Farmington, NM
Chris Crabtree	Science Applications International Corporation	Santa Barbara, CA
Orion Crawford	Concerned Citizen	Farmington, NM
Nicholas Cullander	Concerned Citizen	Farmington, NM
Pat Cummins	Western Governors' Association	Bayfield, CO
Michele Curtis	Caterpillar	Denver, CO
Mike D'Antonio	Public Service Company of New Mexico	Albuquerque, NM
Joseph Delwiche	US Environmental Protection Agency, Region 8	Denver, CO
Sam Duletsky	Transwestern Pipeline Co.	Houston, TX
Gus Eghneim	Wood Group	Farmington, NM
Joe Elliott	Industrial Maintenance Service	Lawndale, CA
Bob Estes	URS Corporation	Phoenix, AZ
Melissa Farmer	Stateside Associates	Arlington, VA
Don Fernald	Enterprise Products Operating LP	Santa Fe, NM
Karin Foster	Independent Petroleum Association	Arlington, VA
Erich Fowler	Denver University Student	Denver, CO
Brett Francois	San Juan Basin Health Department	Durango, CO
Susan Franzheim	Concerned Citizen	Durango, CO
Dan Frazer	Sierra Club	Santa Fe, NM
Virgil Frazier	Southern Ute Indian Tribe Growth Fund	Ignacio, CO
Steve Frey	US Environmental Protection Agency, Region 9	San Francisco, CA
Ron Friesen	ENVIRON International Corporation	Novato, CA
Maureen Gannon	Public Service Company of New Mexico	Albuquerque, NM

Gary Gates	Corporate Compliance, Inc.	Thornton, CO
Gordon Glass	Sierra Club / Democratic Party	Farmington, NM
Lori Goodman	Diné CARE	Durango, CO
Art Goodtimes	San Miguel County	Telluride, CO
Susan Gordon	Concerned Citizen	Farmington, NM
Bill Green	New Mexico Environment Department	Santa Fe, NM
Lee Gribovicz	Western Governors' Association / WRAP	Cheyenne, WY
Sherri Grona	Northwest New Mexico Council of Governments	Farmington, NM
Dick Grossman	Concerned Citizen	Durango, CO
Bill Hagler	NM Utility Shareholders Alliance	Albuquerque, NM
Jacob Hegeman	Stateside Associates	Arlington, VA
Daniel Herman	Wyoming Department of Environmental Quality	Cheyenne, WY
Robert Heyduck	New Mexico State University	Farmington, NM
Cheryl Heying	Utah Department of Environmental Quality	Salt Lake City, UT
Ethan Hinkley	Southern Ute Indian Tribe	Ignacio, CO
Suzanne Holland	Chevron North America	Houston, TX
Rima Idzelis	Stateside Associates	Arlington, VA
Sethuraman Jagadeesan	Whiting Petroleum	Denver, CO
Chris Jocks	Fort Lewis College	Durango, CO
Keith Johns	Sithe Global Power, LLC	New York, NY
Keith Johnson	San Juan County / City of Bloomfield	Bloomfield, NM
Isabella Johnson	Concerned Citizen	Farmington, NM
Matt KeeFauver	City of Cortez	Cortez, CO
Lisa Killion	New Mexico Environment Department	Santa Fe, NM
Aaron Kimple	Friends of the Animas River	Durango, CO
Richard Knox	URS Corporation	Phoenix, AZ
Judy Kuettel	Concerned Citizen	Durango, CO
Brian Larson	San Juan Basin Health Department	Durango, CO
Chris Lee	Southern Ute Indian Tribe EPD	Denver, CO
David LeMoine	Concerned Citizen	Farmington, NM
Kandy LeMoine	Concerned Citizen	Farmington, NM
Renee Lewis	Oil and Gas Accountability Project	Durango, CO
Doug Lorimier	Sierra Club	Santa Fe, NM
Charles Lundstrom	New Mexico Environment Department	Grants, NM
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Chandler Marechal	La Plata County	Durango, CO
Louise Martinez	NM Energy, Minerals and Natural Resources Dept.	Santa Fe, NM
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Ann McCoy-Harold	Representing Senator Allard	Durango, CO
Lisa Meerts	The Daily Times & Four Corners Business Journal	Durango, CO
Rachel Misra	Navajo Nation Environmental Protection Agency	Fort Defiance, AZ
Tom Moore	Western Governors' Association	Fort Collins, CO
Michelle Morris	Navajo Nation Environmental Protection Agency	Fort Defiance, AZ
Gary Napp	Environment, LLC	Paoli, PA
David Neleigh	US Environmental Protection Agency, Region 6	Dallas, TX
Jan Neleigh	Concerned Citizen	Bayfield, CO
Charlene Nelson	Navajo Nation Environmental Protection Agency	Fort Defiance, AZ
Dan Olsen	Colorado State University	Fort Collins, CO
Dianna Orf	Orf and Orf	Denver, CO
Roy Paul	Concerned Citizen	Mancos, CO
Mark Pearson	San Juan Citizens Alliance	Durango, CO
Nathan Plagens	Sithe Global Power, LLC	Farmington, NM
Roger Polisar	New Mexico Environment Department	Carlsbad, NM
Alison Pollack	ENVIRON International Corporation	Novato, CA
James Powers	USDA Forest Service	Durango, CO
Patricia Prather	Concerned Citizen	Farmington, NM

Jim Ramakka	USDI Bureau of Land Management	Farmington, NM
Brinda Ramanathan	Serafina Technical Consulting, LLC	Santa Fe, NM
Liana Reilly	National Park Service	Lakewood, CO
Jeff Robinson	US Environmental Protection Agency, Region 6	Dallas, TX
Dennis Roundtree	Onsite Power Inc.	Aurora, CO
Larry Rule	Montezuma County	Cortez, CO
Edward Rumbold	USDI Bureau of Land Management	Farmington, NM
James Russell	ENVIRON International Corporation	Novato, CA
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Ken Salazar	US Senator	Durango, CO
Robert Samaniego	New Mexico Environment Department	Santa Fe, NM
Martin Schluep	Kleinfelder, Inc.	Albuquerque, NM
Judy Schuenemeyer	League of Women Voters, Cortez	Cortez, CO
Runell Seale	Enterprise Products Operations, LLC	Farmington, NM
Pat Senecal	Town of Ignacio	Ignacio, CO
George Sharpe	City of Farmington	Farmington, NM
Chris Shaver	National Park Service	Denver, CO
Vic Sheldon	Caterpillar Inc., Global Petroleum Group	Houston, TX
George Sievers	Concerned Citizen	Durango, CO
Elaine Slade	Concerned Citizen	Hesperus, CO
Ken Spence	Concerned Citizen	Durango, CO
Bob Spillers	New Mexico Environment Department	Santa Fe, NM
Karen Spray	Colorado Oil & Gas Conservation Commission	Durango, CO
Jay Stimmel	New Mexico Environment Department	Santa Fe, NM
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Dirk Straussfeld	Sithe Global Power, LLC	New York, NY
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Lany Weaver	New Mexico Environment Department	Santa Fe, NM
Wally White	La Plata County	Durango, CO
John Whitney	Representing Congressman John Salazar	Durango, CO
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Leslie Witherspoon	Solar Turbines, Inc.	San Diego, CA
Bill Witt	Concerned Citizen	Brighton, CO
Aaron Worstell	URS Corporation Denver Tech Center	Denver, CO
Winfield Wright	Southwest Hydro-Logic	Durango, CO
Orion Yazzie	Diné CARE	Aztec, NM
Jim York	Sky Ute Sand & Gravel	Farmington, NM
Angela Zahniser	USDI Bureau of Land Management	Washington, DC
Jeanne Zamora	Indian Health Service	Rockville, MD
Christi Zeller	La Plata County	Durango, CO
Alan Zumwalt	Archuleta County Public Works Department	Pagosa Springs, CO

Background and Purpose

Overview

The states of Colorado and New Mexico convened the Four Corners Air Quality Task Force (Task Force) in November 2005 to address air quality issues in the Four Corners region and consider options for mitigation of air pollution. The Task Force is comprised of more than 100 members and 150 interested parties representing a wide range of perspectives on air quality in the Four Corners. Members include private citizens, representatives from public interest groups, universities, industry, and federal, state, tribal and local governments.

This report represents a two-year effort of the Task Force and is a compendium of options to address air quality concerns in the Four Corners. This report is the result of hundreds of hours of time volunteered by Task Force members. The report's contents should not be construed as the conclusive findings or consensus-based recommendations of all Task Force members, but rather as an expression of the range of possibilities developed by this diverse group. This report provides a unique and invaluable resource for the agencies responsible for air quality management in the Four Corners area.

Air Quality Background

The Four Corners area is home to more than 400,000 people in 10 counties. Beautiful landscapes, rich history and cultural heritage, and numerous outdoor activity opportunities drive a significant tourism industry. The area is also home to an extensive energy development sector that is experiencing unprecedented growth. Furthermore, population and urbanization is increasing in the area. Increases in industrial development and population generally bring increases in air pollution. Good air quality is important to both residents and visitors in the Four Corners area, and immediate attention to this resource is necessary to ensure its protection.

The Clean Air Act sets forth a variety of air quality standards and goals. For example, the U.S. Environmental Protection Agency (EPA) sets National Ambient Air Quality Standards for the most prevalent pollutants that are considered harmful to public health and the environment. The EPA, states, and some tribes are responsible for keeping clean areas clean under the Clean Air Act's Prevention of Significant Deterioration program. In fact, the Four Corners area air quality is potentially subject to the requirements of four states, numerous tribes, EPA and Federal Land Managers. This jurisdictional array was a primary driver for the need for this task force.

The Prevention of Significant Deterioration program requires regulatory agencies to determine whether air pollution is causing adverse impacts to water, vegetation, soils and visibility in our National Parks and Wilderness areas. The states are currently working on plans to improve visibility as required by the federal Regional Haze Rule.

One pollutant that has been decreasing across the west is sulfur dioxide. However, ozone, nitrates (formed from Oxides of Nitrogen) and particulate matter are of particular concern in the Four Corners region due to increased oil and gas operations, power plants, and general growth. This area has not exceeded the federal health standards for these pollutants, but air monitoring in the region has shown that concentrations are approaching federal ambient air quality standards for ozone. Regulatory agencies are working to ensure that pollutant levels in the Four Corners region remain below the federal air quality standards. These same pollutants also impair visibility—hindering the ability of an observer to see landscape features—and affect other sensitive resources such as water quality and ecosystems in the region. Views in the Four Corners area are routinely impaired by air pollution.

Another pollutant of concern in the Four Corners region is mercury. Mercury is a naturally occurring metal that is released into the environment from industrial operations and household waste, including coal-fired power plants, crematoria, disposal of common household products and equipment, and mining. Mercury builds up and remains in the ecosystem and can be found in toxic levels in fish in many areas. The EPA promulgated the Clean Air Mercury Rule in 2005 to permanently limit and reduce mercury emissions from coal-fired power plants through the year 2018. States are currently working to implement this program.

Four Corners Air Quality Task Force

The agencies responsible for managing air quality in the Four Corners include the four states (Arizona, Colorado, New Mexico and Utah), the federal agencies (EPA, the U.S. Department of the Interior's Bureau of Land Management and National Park Service; the U.S. Department of Agriculture's Forest Service), and the tribal governments (Navajo Nation Environmental Protection Agency, Ute Mountain Ute, Jicarilla Apache and the Southern Ute Indian Tribe's Air Quality Department). These agencies are addressing the air quality issues discussed above, and believe the input of the residents, representatives of industry and environmental groups is important in developing effective air management strategies. The EPA, BLM, state agencies and some tribes have authority to control sources of air pollution.

In 2004, these agencies decided to work together to explore collaborative ways to manage air quality in the Four Corners area. The agencies agreed that an organized and sustained public process would be beneficial to developing meaningful air quality management strategies for the area. In November 2005, the states of New Mexico and Colorado officially convened the Four Corners Air Quality Task Force (Task Force).

The purpose of the Task Force was to bring together a diverse group of interested parties from the area to learn about and discuss the range of air quality issues and options for improving air quality in the Four Corners area. It was decided at the outset that the Task Force would be a process completely open to anyone with an interest in air quality issues in the Four Corners area. This meant that member participation fluctuated from meeting to meeting, although no meeting had fewer than 65 attendees and Task Force participation in total reached some 250 individuals (Task Force members and interested parties combined).

Initial work of the Task Force has already resulted in the implementation of one "interim" recommendation: the Bureau of Land Management has required new and replacement internal combustion gas field engines of between 40 and 300 horsepower to emit no more than two grams of nitrogen oxides per horsepower-hour; and, in Colorado, all new and replacement engines greater than 300 horsepower must not emit more than one gram of NOx per horsepower-hour. In New Mexico, all new and replacement engines greater than 300 horsepower must not emit more than 1.5 grams of NOx per horsepower-hour. These requirements apply to oil and gas development within the Bureau of Land Management's jurisdiction.

The Task Force Process

A process was developed that would easily accommodate new members throughout the two-year time period, but provided enough continuity so that a work product could be developed. The Task Force was divided into five working teams: three "source" groups: Power Plants, Oil and Gas, and Other Sources; and two "technical" groups: Cumulative Effects and Monitoring. The purpose of the work groups was to exchange ideas and information, discuss mitigation options, receive input, and coordinate the development of the mitigation options relating to those sectors. The technical work groups coordinated existing data and analyses that could inform the work of the Task Force, as well as identified additional air quality analyses and monitoring that may be helpful to the responsible agencies in developing air quality management plans.

The Task Force met face-to-face on a quarterly basis from November 2005 through November 2007. These meetings took place in Farmington, New Mexico and Durango and Cortez, Colorado. Additional work was carried on between meetings via conference call, and some smaller group meetings were held as needed. The website developed for the Task Force was the primary vehicle of on-going communications with Task Force members, and was hosted by the State of New Mexico at: http://www.nmenv.state.nm.us/aqb/4C/index.html. The website aided in the Task Force being an open forum for the exchange of ideas, as well as an educative tool, resource and bulletin board for Task Force members, interested parties and others.

Participants in the Task Force drafted mitigation ideas throughout the process following a simple format to promote consistency. Participants could also provide written input at any time, which was incorporated into the document on an on-going basis. Since it was not the intention of the Task Force for all members to come to consensus, the convention of a "Differing Opinion" was used so that individual members could share views that contrasted with what the author(s) had written. These appear throughout the report with the words "Differing Opinion" in bold print followed by the commenter's language.

In addition to Task Force member on-going input, the process included a public review period that enabled any interested individual (including Task Force members) to review and comment on the document. These comments were then reviewed by Task Force members, and revisions were made as members deemed appropriate. The public review comments are appended to each work group section of this document.

The Four Corners Air Quality Task Force implementation was mainly funded by grants from the states of New Mexico and Colorado; the U.S. Department of Interior, Bureau of Land Management and National Park Service; the U.S. Department of Agriculture, Forest Service, and the U.S. Environmental Protection Agency. In addition, many citizens, private corporations, non-profit organizations and other agencies provided in-kind support as well as resources to advance the work of the Task Force.

The Task Force Report

The Task Force Report is comprised of more than 125 mitigation options written by Task Force members and is the product of their work together over the two year period. These options describe possible strategies for minimizing air pollution impacts in the Four Corners area. These options are organized by source sector: Oil and Gas, Power Plants, and Other Sources, with an additional section on Energy Efficiency, Renewable Energy and Conservation that addresses all sources. Each group first brainstormed a broad spectrum of possible mitigation options and then decided on which options would be drafted into mitigation option papers. Those options that were not drafted are included in the Table of Mitigation Options Not Written with the group's rationale for not including them as written papers in this document.

There are also two technical sections: one on monitoring that discusses analysis gaps and offers ideas for improved monitoring in the area, and one on cumulative effects that provides some quantified estimates of emission reductions for some of the options, as well as ideas for additional analysis. Ideally, each option would have included an analysis regarding quantified air quality and other environmental, economic and other costs and benefits, as well as the costs to implement. Such analyses can be extremely resource and time-intensive and as such, could not be included for all options, but was included in options as available.

The Path Forward

This report will be considered by the federal, state, tribal and local agencies as they develop air quality and land management strategies, which may include developing new and revising existing regulations, supporting new legislation, developing new outreach and information programs, and developing and/or expanding voluntary programs for emission reductions. For instance, states may pursue some mitigation strategies as they develop strategies to enact specific, mandatory programs such as Regional Haze. The Bureau of Land Management may use options such as permit requirements for energy production. Industries may voluntarily practice a mitigation strategy to avoid further regulation.

This work of implementation will be done cooperatively among all of the agencies when appropriate, and individually as needed. Some of this work will include additional analyses of incentives for voluntary programs, air quality modeling, economic analyses, feasibility studies, and review of additional monitoring data. To enact new regulations, every jurisdiction requires a different level of analysis be performed, so there may be varying levels of study on any given option that a regulatory agency decides to pursue. The analyses and recommendations of the Cumulative Effects and Monitoring work groups will inform these agency processes.

Conclusion

An initial goal expressed at the first Task Force meeting was for greater awareness and understanding of air quality issues among the residents of the Four Corners area. In the end, the Task Force provided a unique forum for learning, the exchange of ideas and information, and a venue for all people in the area with interest in air quality to get to know one another. The result is a better informed and cohesive group of individuals who can speak to and support air quality management in the Four Corners area. The group became so cohesive that it was decided to reconvene the Task Force in approximately six months time to review progress made from the date of the Task Force Report's completion.

The work of the Task Force represents an invaluable resource to the agencies responsible for air quality management in the Four Corners area, and also for the general public as air quality management planning moves forward. The Task Force Report and process provides a model for other areas with similar concerns.

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Oil and Gas

Oil and Gas: Preface

Overview

The Oil & Gas Work Group of the Four Corners Air Quality Task Force was tasked with analyzing emission mitigation strategies for this industrial sector. For each Mitigation Strategy, and to the extent practicable, the Work Group documented the description of each strategy as well as implementation and feasibility considerations.

Participation in the Oil and Gas Work Group involved state, local and tribal air quality agencies, federal land management agencies, industry representatives, public citizens, and representatives of environmental organizations. Over six working sessions and many monthly conference calls, the work group identified more than 75 potential mitigation strategies. These mitigation strategies were then discussed and either drafted as a mitigation option paper, or eliminated from further analysis where a rationale to do so existed (see Table at the end of this document). The vast majority of the options discussed are represented herein by mitigation option papers for a total of 51.

Organization

The Oil and Gas industry is generally divided into sub-sections according to process. The Work Group used this progression in process to address each stage of the industry, with the exception of exploring Mitigation Options for Engines as a unique section that applies across the processes in the industry. For the purposes of organization and analysis of available Mitigation Strategies, the Oil and Gas portion of the TF Draft Report follows the sequence of definitions as identified below:

1. **Engines:** The work group addressed engines as a separate category in its analysis attributable to all processes in the oil and gas industry. The mitigation strategies were created to address the subcategories of stationary or mobile/non-road engines, drill rig engines, and turbines.
2. **Exploration & Production (E & P):** the work group defined E & P as the upstream sector of the oil and gas industry, including all activities associated with drilling, completion, and putting the well on-line. The work group identified and developed mitigation strategies for specific equipment in E&P, including oil/condensate tanks, dehydrators/separators/heaters, fugitive emissions associated with pneumatic operations, completions, and wellhead considerations.
3. **Midstream:** the work group defined Midstream Operations as occurring after custody transfer, including facilities such as compressor stations, gas processing plants, and transmission or storage of natural gas. Where appropriate, the work group devised mitigation strategies that avoided general overlap with E & P options, and concentrated primarily on options unique to the “midstream operations” that were not otherwise examined in the context of E&P operations.

The Work Group also identified and developed mitigation strategies that address **Overarching** and **Energy Efficiency and Renewable Energy** appropriate for consideration of application to the oil and gas industry.

ENGINES: STATIONARY RICE

Mitigation Option: Industry Collaboration

I. Description of the mitigation option

Overview

- This option explores the possibility of industry collaboration with engine manufacturers to achieve and reliably maintain emissions at or below prescribed levels for upcoming emission standards (i.e., NSPS for engines) on new engines. Such technologies could include but are not limited to lean burn or non-selective catalytic converters (NSCR) with air-to-fuel ratio controllers. The focus on such an effort would be on natural gas fired engines site rated at less than 300 hp.

Air Quality and Environmental Benefits

- This option would result in air quality improvement since all new engines built would meet lowest achievable emission controls at that time for criteria pollutants.
- **Differing opinion**: Reasonably available control technology is the accepted term used by EPA, industry, and regulatory entities versus lowest achievable emission controls that have a different connotation.

Economic

New Engines:

- Depending on the final emission levels established through this effort, operators might have to spend resources ensuring that prescribed emissions limits are being maintained.
- If through this option emission levels are set at levels lower than upcoming federal standards, then detailed engineering/economic analyses should be conducted to examine the incremental cost to control (over the federal regulatory baseline) and to determine if such additional controls are consistent with other programs.

Existing Engines:

- If such a program were expanded to include the retrofitting of all existing engines with current emission control technology, this would require a large capital investment from companies to achieve this result. This would result in replacement of older compressor engines, particularly those less than 200 hp,
- **Differing Opinion:** new engines would be a significant cost to the oil and gas industry. The salvage value of older compressors is a fraction of the cost of a new compressor engine.
- It would require companies to commit to ordering new engines over a prescribed time, likely ahead of when older units would have been replaced.
- The manufacturers would need confirmed orders to justify re-tooling their plants to meet the demand.

Trade-offs

- The use of given emission control technology could result in other emissions. For example, the use of lean-burn technology on a large scale would result in incremental emissions of formaldehyde. If NSCR is used on a large scale, it is believed ammonia emissions would result. However, it is not known if these emissions would be significant.
- Some engine manufacturers that cannot meet the demand and/or re-tool their factories could lose their market share in the San Juan Basin. Need to ensure this does not create any restraint of trade concerns.

II. Description of how to implement

A. Mandatory or voluntary: It could be both. The companies could begin a process of placing new orders voluntarily or the agencies, through regulatory/rules, could require emission levels that necessitate ordering new compressor engines.
Differing opinion: If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies.
Differing opinion: Not appropriate. If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

III. Feasibility of the option

A. Technical: None identified although some field trials and bench scale tests are probably necessary to assess actual emissions on the new engines.
Differing opinion*:* EPA has assessed the technological feasibility of controlling these types of engines (See NSPS Mitigation Option Paper below.)

B. Environmental: Yes, from the Cumulative Effects group depending upon what type of emission control technology is preferred. The control technology that will be used will be based on the emission level selected, the lowest cost method of achieving the desired level of emission reduction and the reliability of maintaining emissions at the desired level. Ultimate decisions regarding control options should be based on measurable improvements in ambient air quality.

C. Economic: Economic burdens associated with engine replacement and manufacturer re-tooling are likely to be substantial.

IV. Background data and assumptions used

Emission inventories compiled for the Farmington, NM BLM Resource Management Plan (2003) and Southern Ute Indian Reservation Oil and Gas Environmental Impact Statement (2002).

- Preliminary discussions with companies and engine manufacturer representatives.
- Will need to integrate any more recent emissions inventory data from the Cumulative Effects Group.

V. Any uncertainty associated with the option (Low, Medium, High)

High, especially pertaining to economic feasibility and availability of field proven engines. High due to economics of replacing a large fleet of existing compressor engines and the timing that would be required to begin manufacturing a number of small horsepower engines.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

May need to verify with other work groups if manufacturing a large number of new compressor engines, particularly in the smaller horsepower range, could conflict with other new engine initiatives such as building Tier II and Tier III diesel engines and meeting requirements for additional NSPS general regulations.

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Driven Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. Retrofit of internal combustion engines with electric drivers is not generally feasible. Not all compressors can be fitted with an electric motor. This normally requires either a complete package change or, at very least, gear modifications. Electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the electric grid capacity in any given area may limit the size/number of electric engines potentially supportable. The reliability of the grid and the easements also must be considered.

Air Quality/Environmental

- Elimination of local emissions of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities) primarily from coal fired power plants (with higher emissions than natural gas fired engines) or natural gas fired peaking units.
- The "emissions balance" for switching to 4-corners grid electricity is illustrated in the table directly below. As apparent, the switch is not necessarily positive when compared with "modern" gas-fired reciprocating engines. The actual "balance" would depend on the particular engine model being compared to an electrical option.

4 Corners Grid Average Emissions lbs/MWh (From NRDC Database) (Average of PNM, Xcel, and Tri-State)	
SO_2	3.4
NO_x	3.8
CO_2	2,473
Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)	
SO_2	0
NO_x	2.9
CO_2	1,138
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NO_x - 1 g/hp-hr 1 cu ft gas = 1,000 btu	

See also Cumulative Effects Analysis for this option for further emissions analysis.

Economics

- The costs to replace natural gas fired compressor *engines* with electric motors would be costly. Not all natural gas fired compressors can be fitted directly with an electric motor. This normally requires a complete package change or at very least, gear modifications.

- The costs of getting electrical power to the sites would be extremely high in most cases. It could require a grid pattern upgrade, which could costs millions of dollars for a given area. Maintenance and repair costs associated with the electrical power source are not included.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal-fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities. Co-generation produces both power and steam; as there is not a market for the steam, this might just be a need for additional power plants or combined cycle plants. Lead time and cost for permitting and new base load generating facilities could be substantial.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.
- When comparing emissions from electric generating facilities used to power electric compressors versus natural gas fired compressors, differences in emission rates as well as overall energy efficiency must be examined.

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. Extensive capital investments could be required if new generating facilities are needed to meet the electrical demand of this option.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary based on economics of meeting emission reduction requirements and/or initiatives and feasibility of implementation.

B. Indicate the most appropriate agency(ies) to implement: No agency action needed to implement a voluntary program.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area and overall available electrical power for large-scale conversion in a given geographic area.

B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).

C. Economic: The economics of implementing this option are much larger than stated above. Considerations such as (but not limited to): 1) cost of energy; 2) electrical demand; 3)reliability; and 4) efficiency need to be included in such an analysis. Costs to control calculations are needed to determine if they are consistent with other options being considered. Modeling needs to be conducted to evaluate if potentially shifting emissions from natural gas to coal would result in ambient air quality benefits.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option (Low, Medium, High):

HIGH to MEDIUM based on land accessibility (easements), electric source availability and reliability of uninterrupted supply, advancing GHG legislation/regulation, and economics.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups:

Possibly the Cumulative Effects Group due to indirect emission increases from coal-fired plants. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Electric Compression (Alternative - Onsite Generators)

I. Description of the mitigation option

Overview

As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers."

The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc.

Air Quality/Environmental Benefits

The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx at 900 rpm, which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines.

The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation.

The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region.

Economics

The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $ 1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost.

The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines.

The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines.

Tradeoffs

In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible.

The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated.

Burdens

The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option.
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

Gas electrical generator information was obtained from Caterpillar's Website.

V. Any uncertainty associated with the option (Low, Medium, High):

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups

Mitigation Option: Optimization/Centralization

I. Description of the mitigation option

Overview

- This option outlines the deployment of internal combustion engines used as the source to power various oil and gas related operations with the appropriate horsepower rated to the need of the activity being conducted. The advantages of this approach would be reducing the cumulative amount of horsepower deployed, which may reduce emissions through elimination of compression and optimization of compressor fleets. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.
- Overall fleets of engines in the San Juan basin are currently believed to be loaded at about 50% available hp. This is determined by looking at installed hp, volume of gas being moved, and pressure differentials in the field. These load factors are dynamic and constantly changing.
- **Differing opinion:** Emissions from compressor engines are based on the amount of fuel used (a function of capacity and load). Assuming that emission factors do not change with load (this may or may not be true), as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions. The assumption that all engines have the same emissions is not true and thus this option is based on a flawed premise. In reality, analysis of engine utilization in the region indicates that larger engines have lower emissions than smaller engines.

Air Quality and Environmental Benefits

- The benefits could be lower emissions calculated against horsepower assuming smaller horsepower engines would be deployed to replace larger engines. This would be accomplished by either design or as field conditions changed at individual sites or by centralizing compression horsepower at central site. While efficiency may improve, application of smaller engines working at or near full load may increase NOx emissions relative to an oversized unit operating at reduced load.
- **Differing opinion**: Needs to be framed for applicability to engine type, size, etc.

Economics

- Optimization:
  - The economics of replacing individual site compression with properly sized horsepower could be difficult. Some companies bought individual site compression based upon technical considerations at that time. Unfortunately, due to changing field conditions, which could not be contemplated when the original engine was bought, the existing engine may not be sized properly. To require the purchase of new compressors for changing field conditions over the life of a natural gas field will be an economic strain on the operators.
  - The salvage value of the compressor being replaced is a fraction of a new one.
  - Replacing engine compression several times during the life of well would not be economic. Purchasing new compression with operating conditions in a given field could jeopardize the economics of a well(s).
  - If the engines are rentals, the situation is much more flexible depending upon the lease/contract with the vendor. In the San Juan Basin most smaller well site

    compression is a combination of purchased and leased, both of which depend upon the individual operator's preferences.

- Centralization
    - As with optimization, field conditions change and to size equipment properly on a horsepower basis may require numerous iterations of replacement.
    - As above with optimization, the economics of replacing units to fit ever changing field conditions in the cases where the equipment has been purchased will create economic challenges for the operators.
    - For leased units, flexibility would be greater, but would depend upon the lease/contract with the vendor.
    - Use of larger centralized engines increases the opportunity to use low emission lean burn engines.
- Lines and gathering system would probably need to be redesigned and replaced for efficiency, otherwise line losses and bottlenecking could create operation issues. Besides causing increased surface disturbance the economics of line redesign and replacement are probably beyond the economic feasibility limits of the fields in the area.

Tradeoffs

- The tradeoffs for centralization appear to have the most concern.
- There could be an air quality benefit by centralizing, but there would be more long-term surface disturbance involved and dust generation from construction. For instance, a central compressor serving multiple sites would likely need to be built at a new site making it more equitable from an operational perspective to serve its purpose. A new central site would then require surface disturbance for a new site and, whether an existing site could be used or not, underground piping from the central site to multiple sites would be necessary. This could result in permanent new disturbance (if a new site had to be built) and short-term disturbance for the pipeline to multiple sites until this was reclaimed.
- While above ground pipelines are a possibility, for safety reasons these have not been generally used in the San Juan Basin.
- Emissions tradeoffs based on relative operating loads would need to be considered.
- There is potential for increased noise for those living close to these centralized facilities.
- Potential for increased permitting.
- It is possible that centralized compressor stations would become Part 70 or 71 facilities (Title V under the CAA) and would require substantial testing and record keeping on the part of operators and agencies.

Burdens

- The burden for optimization and/or centralization would fall to industry. The cost of pursuing this approach should be carefully considered due to the impact it could have on the economic viability of a given well.
- Increased permitting places burden on regulatory agencies and industry.

II. Description of how to implement

A. Mandatory or voluntary. This option should be voluntary given the economic impacts.

B. Indicate the most appropriate agency(ies) to implement. NA; would be voluntary by the companies since they must assess the technical and economic feasibility.

III. Feasibility of the option

A. Technical: Technical concerns would include trying to size compression properly either with optimization or centralization considering the unknowns associated with changing field conditions.

B. Environmental: Potential environmental benefit would need to be more closely reviewed depending upon the specific scenario. At best, little or marginal benefits are likely to be realized.
C. Economic: While some centralized options could be considered, well-level optimization is not economically feasible considering all the variables that exist with field operations. .

IV. Background data and assumptions used

Discussions with company field and engineering staff

- Input from engine manufacturers and engine consultants

V. Any uncertainty associated with the option (Low, Medium, High)

High. For optimization: The sizing of engines is based on the maximum flow from a well. As wells decline through time the initial hp needs are no longer appropriate. Replacement of this existing hp would be cost prohibitive. For centralization: collection systems are already in place and centralizing would require retrofitting, which is cost prohibitive. Further, in NM, well sites and gathering systems have different owners. Competitors would need to collaborate to centralize, which would be unlikely.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None identified at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

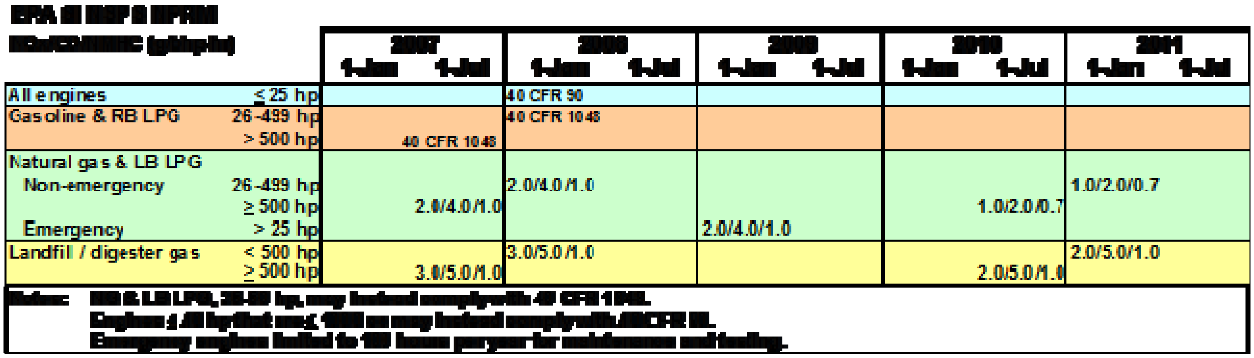
Mitigation Option: Follow EPA New Source Performance Standards (NSPS)

I. Description of the mitigation option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:



EPA SI NSPS NPRM
NOx/CO/NMHC (g/bhp-hr)

		2007		2008		2009		2010		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	> 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	≥ 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

Notes: [illegible]
[illegible]
Emergency engines limited to 100 hours per year for maintenance and testing.

All new stationary engines in the Four Corners region will have to meet the new EPA requirements. Deferring to the EPA NSPS will provide the most cost-effective emissions control because manufacturers will have compliant products for sale across much of the country. Compliance with the EPA NSPS will provide a level of emissions control that is federally mandated and will impose a certain financial burden that is not elective. The premise for this mitigation option is that additional control beyond the EPA NSPS would not be needed for new engines.

II. Description of how to implement

A. Mandatory: Compliance with the EPA NSPS will be mandatory. This would apply to all newly manufactured, modified and reconstructed engines after the NSPS effective dates. 'Modified' engines are those undergoing a change that would result in an increase in emissions, while 'reconstructed' engines are those undergoing rebuild work that costs at least 50% of the cost of a new unit. See 40 CFR 60.2 for further definitional details.

Differing Opinion: Voluntary: Applicability of the NSPS requirements could be considered for existing engines. Because a large number of existing engines would require extensive rework or replacement to achieve the NSPS levels, any such approach should be a voluntary, incentive-based program.

B. Indicate the most appropriate agency(ies) to implement**:** No additional work would be needed other than what EPA is mandating. Any permitting would continue to be at the State's discretion. The appropriate agencies for any incentive based applicability to existing engines would need to be determined.

III. Feasibility of the option

A. Technical: EPA has spent the past year working with engine manufacturers during its development of the CI and SI NSPS. The requirements have been shown to be technologically feasible.

B. Environmental: EPA's regulatory documents do/will provide details of the expected environmental benefits and the conclusion that this level of control is appropriate for areas not in advanced levels of non-attainment.

C. Economic: EPA's Regulatory Impact Analyses (RIA) for the two rulemakings will provide explanations of the expected costs of compliance.

IV. Background data and assumptions used

None beyond material in EPA's rulemakings.

V. Any uncertainty associated with the option (Low, Medium, High)

Essentially no uncertainty that the NSPS will soon provide new, emissions-controlled stationary engines in the Four Corners region.

VI. Level of agreement within the work group for this mitigation option

The RICE subgroup anticipates Oil & Gas Workgroup consensus that EPA's mandatory compliance with its new NSPS will provide appropriate short- and long-term emissions control that is commensurate with the needs of the Four Corners region.

VII. Cross-over issues to the other source groups

Assistance from Cumulative Effects Work Group needed to assess air quality benefits in the Four Corners area. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Adherence to Manufacturers' Operation and Maintenance Requirements

I. Description of the mitigation option

Engine manufacturers provide to end-users recommended procedures for the initial installation and adjustment of spark-ignition (SI) engines, in addition to on-going preventative maintenance recommendations. Adherence to these recommendations provides long-term, intended performance, emission levels, durability, etc. Please see EPA SI NSPS proposal update below under Section V.

II. Description of how to implement

A. Mandatory or voluntary: While adherence to engine manufacturers' 'recommended' procedures is generally voluntary from a regulatory perspective, this mitigation option instead proposes that such adherence be mandatory. This could be considered for existing engines as well as for new engines. Please see Section V below for further discussion.

B. Indicate the most appropriate agency(ies) to implement: EPA's proposed New Source Performance Standards (NSPS) for, in particular, SI engines, includes several related aspects that will likely be mandatory. Those aspects of engine manufacturers' recommended procedures that are not included in the NSPS could be implemented by the states.

1. 40 CFR 60.4234: **"Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in 60.4233 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine."**

2. 40 CFR 60.4241(f): "Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in 60.4231(d) when operating on that fuel. **The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition.** The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on particular fuels to which the engine is not certified."

3. 60.4243: "**If you are an owner or operator, you must operate and maintain the stationary SI internal combustion engine and control device according to the manufacturer's written instructions** or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators of certified engines may only change those settings that are allowed by the manufacturer to ensure compliance with the applicable emission standards. ...The engine must be installed and configured according to the manufacturer's specifications to ensure compliance with the applicable standards."

4. 60.4245(a): **"Owners and operators of all stationary SI ICE must keep records of...maintenance conducted on the engine."**

III. Feasibility of the option

A. Technical: Prudent operators follow manufacturers' recommended procedures. Properly maintained engines operate more efficiently and at lower total cost. Ignition maintenance, in particular, can have significant impact on the performance and life of catalysts.

B. Environmental: Properly maintained engines produce lower emissions. Instead of a fix-as-fail mentality, proper maintenance can avoid or detect failed O_2 sensors or spark plugs, thus avoiding an increase in HC and CO.
C. Economic: The overall, long-term cost of a properly maintained engine is lower than that of a neglected engine.

IV. Background data and assumptions used

V. Any uncertainty associated with the option Medium. EPA NSPS Update: Mandatory requirement to follow engine manufacturers' recommendations is included in the proposal for optionally certified engines. For engines not certified by engine manufacturers, the owner/operator would have compliance responsibility and would not be required to follow the engine manufacturers' recommendations. Owner/operators are raising concern with EPA over the proposed requirement to follow engine manufacturer recommendations for certified engines or follow the proposed option to seek engine manufacturer approval for alternative operational procedures. Many owner/operators believe their own time-proven procedures are appropriate. Because EPA's final rule will have carefully considered the implications of operational and maintenance practices, the Agency's final outcome should be appropriate for new engines used in the Four Corners area. Any consideration of those requirements for existing engines would need to assess the potential benefits achievable through altering current field practices.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups

Mitigation Option: Use of SCR for NOx control on lean burn engines

I. Description of the mitigation option

NOx emissions from lean burn engines (natural gas and diesel fueled) can be reduced by chemically converting NOx into inert compounds. The most effective equipment to achieve NOx reductions is an SCR (selective catalytic reduction) system.
Differing opinion: SCR is one effective equipment option to achieve NOx reductions.
Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. The overall catalyst reaction is as follows:

$$NH3 + NO + NO2 > N2 + H2O$$

The SCR systems utilize programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements. Sampling cells are utilized for closed loop feedback of dosing requirements depending on the amount of NO measured downstream of the catalyst bed.

SCR system components include catalyst housing, housing insulation, control/dosing panel, exhaust dosing/mixing section, and reactant injector. Depending on the reactant medium, a storage tank will be required with a potential minimum temperature requirement of 40°F. **Differing opinion:** Heated reactant storage may drive limited applicability. Description should be expanded to address handling, associated regulations with monitoring and testing for the system slip and RMPs if applicable. Electrical supply to run the SCR system and instrumentation is required.

SCR systems can be constructed with the addition of oxidation catalysts, for the added conversion requirements of CO, VOCs and Formaldehyde. This oxidation catalyst is a dry reaction and is not dependant on injection of a reactant. See the mitigation option on the use of oxidation catalysts for reduction levels achieved for the pollutants.
Differing opinion: Mitigation Option is 'Use of SCR for NOx control on lean burn engines'; therefore, this paragraph may be out of context.

II. Description of how to implement

A. Mandatory or voluntary
Voluntary: May be enhanced by the state supplementing a percentage of the cost.
B. Indicate the most appropriate agency(ies) to implement

III. Feasibility of the option

A. Technical: Dependent on site readiness, installation and start-up would require 7-10 days. **Differing opinion:** Heated reactant storage may drive limited applicability, especially if power is unavailable. Concerns include security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip. There have been no known applications of this technology for remote unattended oil and gas operations. At the present time there is insufficient information to quantify achievable emission reductions in unattended facilities. The incremental cost to control on lean burn technology is likely to be very high because of the small incremental additional mass reductions as a result of tertiary add on controls. Because SCR uses a dilute aqueous solution, RMP hazards are typically not a concern.
Excessive ammonia slip within a coherent NOx plume may lead to increased NO3 formation. This could result in degradation of visibility even though NOx emissions are reduced.

B. Environmental: Post catalyst NOx levels of <0.15g/bhp-hr.
Differing opinion: <0.15 g/bhp-hr depends on the start point but could imply 95% or greater control. Catalysts optimally start at 90-95% capability but drop over time. Control is sensitive and if it moves off

set point, result is ‘no’ control (vs. reduced control). What is the origin of the stated NOx levels? On what type of engine in what type of service? This appears to be simply an assertion with no backup or verification.

C. Economic: Cost of SCR system and maintenance are an increased cost to the packager and end user. The five-year cost for SCR on a 3-engine rig in the Jonah/Pinedale area of Wyoming was estimated at $5 MM in a demonstration pilot conducted by Shell. This information is available from the Wyoming DEQ.
Differing opinion: Costs of heated storage, additional regulatory compliance, added manpower and increased site security would be the burden of the operator. In addition, the engine must be highly stable for this control to be effective (see environmental note).
See also Cumulative Effects Analysis for this option for further emissions analysis.

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Negative perception of reactant handling and injection, though the technology has proven itself to be very user friendly.
Differing opinion: HIGH: The assertion that this is “user friendly” technology is not aligned with the experiences documented as part of the pilots noted above. In these pilots, the systems required both a vendor representative and consultant on site to keep them operating correctly. Concerns include heating reactant, security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip.
Modeling needs to be conducted to evaluate the potential improvement in ambient air quality (ozone, deposition and visibility).

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups) None.

Differing opinion: The CE group needs to offer an opinion on the effect of additional ammonia emissions at plume height.

See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines

I. Description of the mitigation option, including benefits (air quality, environmental, economic, other) and burdens (on whom, what)

NO_X, CO, HC, and Formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds of nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule. The general catalyst reactions are as follows:

$$NO + CO = N_2 + CO_2$$
$$NO_X + CH_4 = N_2 + CO_2 + H_2O$$
$$NO_X + H_2 = N_2 + H_2O$$

These reactions are reducing the NO_X to nitrogen and oxidizing the fuel and CO molecules. These reactions oxidize some of the CO and NMHC molecules, however further conversion is accomplished with and oxidizing catalyst. The oxidizing reactions are shown below:

$$CO + O_2 = CO_2$$
$$CH_4 + O_2 = CO_2 + H_20$$
$$CnHm + O_2 = CO_2 + H_20$$
$$H_2 + O_2 = H_2O$$

A 3-way catalyst contains both reduction and oxidation catalyst materials and will convert NO_X, CO, and NMHCs to N_2, CO_2, and H_2O. A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR). NSCR is applicable only on stoichiometric engines. A very narrow air/fuel ratio operating range is necessary to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls.

Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an air/fuel ratio controller, emission reduction efficiencies vary through the catalyst. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today. AFRCs are available from both the engine manufacture or can be purchased from an after-market supplier. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: This mitigation option is distinct from the mitigation option on using oxidation catalysts on lean burn engines because NSCR controllers are applied only to rich burn engines. Only applies to true rich burn engines, not effective for 1-2% rated rich-burns. 3-way catalysts are only applicable to stoichiometric (true rich burn) engines, potential is to drive the exhaust temperature up. Oxygen, oil slip past engine rings, and poor fuel quality may destroy the catalysts.

II. Description of how to implement

A. Mandatory or voluntary:

Voluntary: May be enhanced by state funding a percentage of the cost.

Mandatory: Mandatory enforcement would give the state the power to eliminate, at the minimum, 90% of NO_X, CO, HC, and Formaldehyde emissions from stationary elements.
Differing Opinion: This option should be mandatory, implemented and enforced by the states.
Differing Opinion: 90% is a <u>reasonable</u> not minimum control for NOx and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NOx is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction.

<u>B. Indicate the most appropriate agency(ies) to implement</u>: States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.
Differing opinion: Mandatory implementation of this requirement would only be feasible in a well-crafted permit program administered by the agency having jurisdiction for air quality. BLM does not have regulatory authority for air quality. Although Tribes may have air quality administration authority, very few functional Tribal programs currently exist.

<u>III. Feasibility of the option</u>

<u>A. Technical</u>**:** Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance. Fuel quality limitations are notable, i.e. field gas, biofuel, etc. may damage catalysts.
Differing Opinion: The previous statement is inaccurate; <u>if</u> an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Retrofit installation of catalyst housings and units typically require additional support structure.

<u>B. Environmental</u>**:** Minimum of 90% NO_X, CO, HC, and Formaldehyde emission reduction. Some increase in ammonia emissions would result, however, it is not known if this increase would be significant.
Differing opinion: 90% is a <u>reasonable</u> not minimum control for NOx and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NOx is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction. Issues Associated With the Use of NSCR on Existing Small Engines:

- Engines Operate at Reduced Loads and There is a Problem Maintaining Sufficient Stack Temperature for Catalyst to Work
- On Engines with Carburetors, Difficulty Having the AFR Maintain a Proper Setting
- On Older Engines the Linkage and Fuel Control May not Provide "Fine Enough" Control
- If the AFR Drifts Low, NH_3 Will be Formed in Roughly Equal Amounts to NOx Reduced

<u>C. Economic</u>**:** The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough

engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance. Caterpillar recommends monthly testing with portable analyzer. See approximate control cost analysis as of January 2007 for an example of the cost of NSCR control.

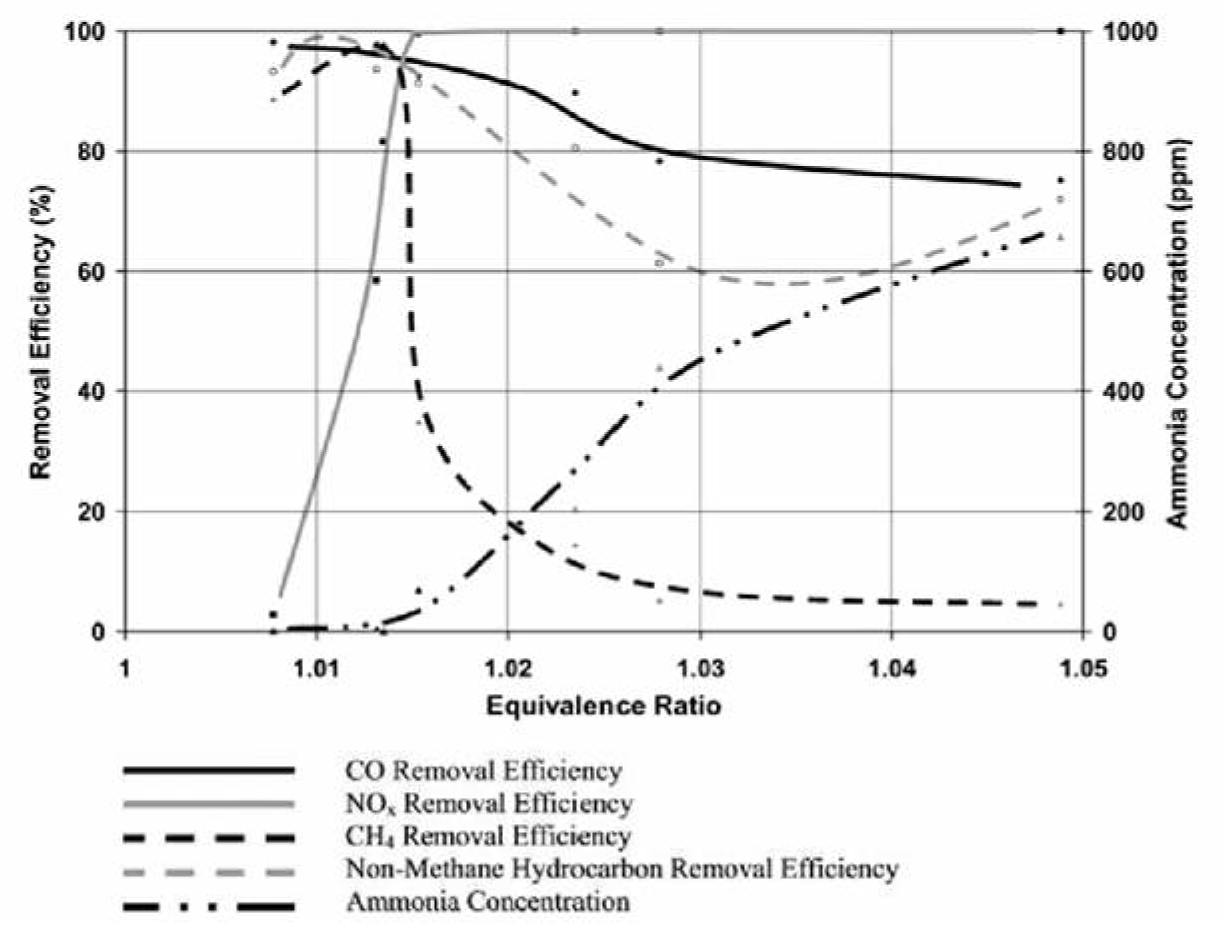
	NSCR Retrofit Costs		
	Compressco Ford 460	*Wauk. 220/330*	*Comments*
Catalyst Housing Purchase	*$2,120*	*$1,600*	
Catalyst Housing Purchase w/Silencer	*$2,650*	*$1,950*	
Average Housing Purchase	*$2,385*	*$1,775*	
Catalyst Element Purchase	*$1,000*	*$800*	
Air Fuel Ratio Controller Purchase	*$2,950*	*$2,950*	
"Rebuild" of Fuel and Air Control System on Older Engines			
Electricity for Air Fuel Ratio Controller - Purchase of solar power unit	*$350*	*$350*	*Alternator and Battery or Solar and Battery*
Installation of Housing and Catalyst	*$1,080*	*$1,080*	*Assumes one welder and one helper for one full day*
Installation/Modification of Support for Housing and Exhaust	*$300*	*$300*	*Estimate of materials - Labor in item above*
Installation of Electricity	*$540*	*$540*	*Electrician or Mechanic for 1/2 day - includes travel to and from*
Installation and Set-up of Air Fuel Ratio Controller	*$2,160*	*$2,160*	*Electrician or Mechanic and Instrument Technician for one day - includes travel time to and from*
Incremental Skid Cost for New Engine	*$1,000*	*$1,000*	
Taxes, Freight, Etc. (From EPA Manual)	*$1,077*	*$1,077*	
Total Purchase and Installation - Retrofit	*$11,842*	*$11,032*	
Total Purchase and Installation - New	*$8,225*	*$7,415*	
Maintenance Cost			
Quarterly Change of O2 Sensor + Emissions Monitoring - annual cost	*$320*	*$320*	
Labor/Travel for Above	*$540*	*$540*	*Technician for 1/2 day - includes travel to and from*
Annualized Catalyst Replacement (5 yr life)	*$160*	*$160*	
Total Annual Cost	*$1,020*	*$1,020*	

<u>IV. Background data and assumptions used</u>
1. G. Sorge "Update on Emissions"
Differing opinion: Insufficient information to locate reference.

<u>V. Any uncertainty associated with the option</u> (Low, Medium, High)

LOW, this is a proven technology with years of results. One issue of merit is the production of ammonia through a 3-way catalyst. This issue has been thoroughly researched and the following are the generalized results:
Differing Opinion: MEDIUM: HC is difficult to measure. Drift of control and narrow applicability to only 'true' rich burn engines are significant issues.

The problem of NH3 formation across catalyst equipped rich burn CNG engines is associated with problems of the A/F controllers. If the A/F ratio is allowed to drift rich, considerable NH3 can be formed. This is shown in the following graph:



Differing opinion: Reference is needed for the Graph credentials.

For a variety of reasons the A/F controllers have failed to control at the desired set point, 0_2 sensors failing, a not particularly sophisticated controller, etc. Today's AFRCs are very exact machines with the ability to easily maintain a precise set point. If a rich burn engine is operated with a properly functioning air/fuel ratio controller plus 3-way catalyst, it will meet emissions requirements without producing a noticeable amount of ammonia.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups None at this time.

Differing Opinion: The CE group needs to offer an opinion regarding the impact of increased ammonia emissions in the region. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines

I. Description of the mitigation option

CO, HC, and Formaldehyde emissions from a lean burn engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds, such as carbon dioxide and water vapor. Lean Burn Engines already have low uncontrolled NO_X emission values (Lean burn engines are a form of NOx control and therefore do not have uncontrolled emissions). The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the oxidation catalyst will oxidize (oxidation catalyst) a CO or fuel molecule. The most common method for achieving CO, HC and formaldehyde control this is through the use of an oxidation catalytic converter. The general oxidizing reactions are shown below:

$$CO + O_2 = CO_2$$
$$CH_4 + O_2 = CO_2 + H_20$$
$$CnHm + O_2 = CO_2 + H_20$$
$$H_2 + O_2 = H_2O$$

Air/fuel ratio control helps to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls. However, most air/fuel ratio controllers are utilized to maintain engine performance due to ambient conditions. While it is true that lean burn engines perform better with AFRC units they are not needed for oxidation catalyst performance – the exhaust stream in a lean burn engine has sufficient oxygen under all conditions where the engine will run.
Differing opinion: An electronic air/fuel ratio controller is recommended to help maintain the catalyst efficiency.

Maintaining low emissions in a lean combustion engine using exhaust gas treatment is enhanced by the use of an Air/Fuel Ratio Controller, however, not necessary. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today, from both the engine manufacture in certain cases and after-market suppliers. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: The preceding two paragraphs seem out of place in the context of oxidation catalyst.

II. Description of how to implement

A. Mandatory or voluntary**:**

Voluntary: May be enhanced by state funding a percentage of the cost.
Mandatory: Mandatory enforcement would require give the state the power to eliminate, at the minimum, 90% of CO, HC, and Formaldehyde emissions from stationary elements. Lean Burn Engines already have low uncontrolled NO_X emission values.
Differing Opinion: This option should be mandatory, implemented and enforced by the states.
Differing Opinion: 80% CO destruction is a more likely/sustainable reduction for CO and HC’s. Formaldehyde destruction/control is less certain but is lower than CO or HC’s.
Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

B. Indicate the most appropriate agency(ies) to implement**:** States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.
Differing Opinion: BLM is not appropriate since they are not charged with air quality management. This is the role and responsibility of the States or Tribes.

III. Feasibility of the option
A. Technical**:** Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance.
Differing Opinion: The previous sentence should be deleted – it is not applicable to oxidation catalyst.
Differing Opinion: The previous statement is inaccurate; if an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add-on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Typically, retrofit will require additional support structure for the
B. Environmental**:** Minimum of 90% CO, HC, and Formaldehyde emission reduction.
Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

According to the EPA speciate database, the majority of HC emissions from RICE are methane (C1), which is not a regulated pollutant under the Clean Air Act. Methane is unregulated because it does not enter into photochemical reactions that form ozone. Therefore, from a THC or more importantly a VOC perspective, such controls will do little to improve ambient air quality. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. 80% CO and HC reduction is more likely in an operational mode. HCHO destruction is not completely understood but is lower than CO or HC.
C. Economic**:** The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance.

IV. Background data and assumptions used 1. G. Sorge "Update on Emissions"
Differing opinion: Insufficient information to locate reference

V. Any uncertainty associated with the option (Low, Medium, High) LOW, this is a proven technology with years of results.
Differing Opinion: The uncertainty is not in the emission reduction technology. The uncertainty is in the ambient air quality benefits that would be achieved as a result of implementation of this option.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups None at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Lean Burn Engines

I. Description of the mitigation option

Using gas fueled (reciprocating) **Lean Burn Engines** as the main prime mover in gas compression and generator set applications in the Four Corners area.

Gas engines are the predominant prime mover used to power gas compressor packages. Gas engines are classified as either Rich Burn or Lean Burn. The industry acknowledges a lean burn engine to have an oxygen level measured at the exhaust outlet of about 7-8%. This typically translates into a NOx emissions rating of 2 g/bhp-hr or less. This will be federally mandated through NSPS regulations requiring performance at this rating for both Lean Burn and Rich Burn engines. Currently, a large percentage of engines operating in the Four Corners Area that have a capacity of greater than 500 hp use lean burn technology and achieve, on average, a NOx emission rating of less than 2 g/hp-hr.

Lean burn engines have this lower NOx rating without using a catalyst or any other form of emissions after-treatment. Some lean burn engine incorporate an Air Fuel Ratio Control installed at the engine manufacturing plant.

Typically lean burn engines have a HP rating above 300 HP. This reflects today's manufacturing emphasis.

The main advantage of using a lean burn is in its capability to offer low emissions without after-treatment. In addition, lean burn engines operate at cooler temperatures and may offer longer life between major repairs.

II. Description of how to implement

A. Voluntary – lower emissions should be the goal. How the operator gets there is his selection and responsibility. In other words, allow an operator to either use a lean burn engine without emissions after-treatment or a rich burn engine with emissions after-treatment to achieve the emissions level needed. It is important to note that the majority of engines greater than 500 hp located on the Southern Ute Reservation where there is no minor source permitting program are lean burn or are low emitting engines as a result of post catalyst treatment. This has been a voluntary effort from the operators.
B. Most appropriate agency to implement: EPA and state air boards.

III. Feasibility of the option

A. Technical: Some states have shown preference to accept engines with lean burn technology over rich burn engines using after-treatment. But as of mid-2006 no engine manufacturers offer the lean burn engine at less than 300 HP. So manufacturers would have to develop a new engine to meet this requirement.
B. Environmental: Study the effect of HAPs formation in lean burn emission and whether further reduction is necessary. There has been extensive testing on HAP emissions from lean burn engines and EPA has established MACT standards for major HAP sources that pertain to RICE. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. The consolidated engine rule for SI engines will require HCHO control.
C. Economic: This is the best economic solution when the power rating is available and the total emissions for all pollutants meet the requirement. Typically this is a more economically viable solution than having a rich burn engine with added controls, catalysts and air to fuel ratio.

IV. Background data and assumptions used

Since there are no known lean burn engines under 300 hp, engine manufacturers may be interested in developing them. The development of these engines may be the most acceptable solution to users, EPA, and states. The forthcoming NSPS will encourage engine manufacturers to develop lean burn engines under 300 hp.

V. Any uncertainty associated with the option (Low, Medium, High)

The uncertainty is not in the lean burn technology but in the ability to meet the air emission requirement across all hp ratings (from 25 - 425 hp) and the acceptance of the final composition of the exhaust gases (including HAPs).

Manufacturers are not unwilling to create new technologies but there is a risk associated with the types of investment returns on technologies developed for small engines.

VI. Level of agreement within the work group for this mitigation option

Some believe that after-treatment is the best option. This is acceptable to an engine manufacturer but this option adds cost related to the additional equipment needed, permitting and monitoring process. In addition, there is the suspicion that engines with after-treatment may be working out of compliance at any one point.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

A study should be conducted on what would achieve the lowest emissions:

- lean burns with no after-treatment
- lean burns with oxidation catalysts and AFRs
- or rich burns with catalysts and AFRs.

From the results, select the option that produces the lowest emissions.

Mitigation Option: Interim Emissions Recommendations for Stationary RICE

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Require a 2 g/bhp-hr limit on engines less than 300 HP:

- May lead to 60 to 80 percent reduction in NOx.
- Help with visibility impairment in Class I areas in four corners region. Monitoring data at Mesa Verde and Weminuche Class I Areas clearly shows that NOx (NO3) is responsible for a very small fraction of visibility impairment. Modeling studies using the EPA CALPUFF model suggest that NO3 is responsible for visibility impairment in the Class I Areas. There are numerous examples that demonstrate that CALPUFF significantly over estimates NO3 visibility impairment compared to monitoring data.
- Several manufacturers offer engines that meet this specification, commercially available in two stroke engines only. Four stroke Lean burn engines capable of meeting 2 g/bhp-hr are not yet commercially available in sizes < 300hp.
- NSCR catalytic reduction can be added at reasonable cost. Potential engine durability concerns associated with elevated exhaust temperatures must be addressed when considering reasonable costs of installation of NSCR.
- Ammonia emissions may increase from use of NSCR catalyst.
- Increased ammonia may or may not affect visibility in the region.
- Without implementation, air quality standards may be exceeded.

Require a 1 g/bhp-hr limit on engines larger than 300 HP:

- Lean burn technology is widely available from manufacturers.
- The lean burn technology will help protect visibility in the region.
- The NAAQS and PSD increments will be less affected.
- Deposition of NOx and related compounds would be reduced
  Differing Opinion: Analysis of engine quarterly flue gas testing results indicates that, on average, it is possible to achieve an emission limit of 1 g/hp-hr, however, it may not be possible to achieve this emission level on a continuous basis.

II. Description of how to implement

These limits should be mandatory for all new and relocated engines and potentially for existing engines as well. The most appropriate agencies to implement this would be the FLMs and the New Mexico, Colorado and Southern Ute environment departments.

Existing fleet has limited compressors that meet these performance criteria. Based on NMAQ Letter of Instruction dated August 2005, <300 hp compressors must meet 2g/hp-hr. It should be noted that BLM does not have air quality authority to require any particular emissions performance from engines. This should be implemented through a well crafted minor source permit program administered by the air quality agencies.

Implementation Status for this Mitigation Option
BLM in New Mexico is currently requiring compressor engines 300 horsepower or less to have NOx emissions limited to 2 grams per horsepower hour as a Condition of Approval for their Applications for Permit to Drill. Effective August 1, 2005, BLM New Mexico, Farmington Field Office (FFO) started adding to each APD issued on and after this date a Condition of Approval (COA) requiring a limit on NOx emissions if operator placed a compressor on the location. The specific condition language states the following:

> This permit is contingent on compliance with the New Mexico Environmental Department, Air Quality Bureau's directive that compressor engines 300 horsepower or less have NOx emissions limited to 2 grams per horsepower hour.

This was based on correspondence received by the NM Air Quality Bureau dated June 3, 2005 and June 5, 2005. The FFO developed the language for the COA, which was reviewed by the NM Air Quality Bureau. The operators are required to comply with this COA regardless of whether it is a newly built compressor or a compressor that they bring in from another location or their ware yard and regardless of when the operators places the compressor on the location (i.e. six months later or two years later etc.).

BLM and USFS permits in the Northern San Juan Basin in Colorado involving new and replacement stationary internal combustion gas field engines require the following emission limits, on an interim basis:

- Emission Control (small gas field engines): All new and replacement internal combustion gas field engines of less than or equal to 300 design-rated horsepower must not emit more than 2 grams of nitrogen oxides (NOx) per horsepower-hour. This requirement does not apply to gas field engines of less than or equal to 40 design-rated horsepower.

- Emission Control (large gas field engines): All new and replacement internal combustion gas field engines greater than 300 design-rated horsepower must not emit more than 1.5 gram of NOx per horsepower-hour.

Interim NOx emission requirements for permits on other BLM and USFS lands in southwestern Colorado have not been established at this time. It is expected that NOx emission requirements will be implemented for these areas in the near future, either as a result of several ongoing planning efforts, or on an interim basis until these planning documents are completed.

Interim NOx emission requirements have not been established for gas field engines on the Southern Ute Indian Reservation at this time. Discussions between the Southern Ute Indian Tribe, State of Colorado Environmental Commission, US EPA Region 8, BLM and BIA are ongoing, and it is expected that NOx emission requirements will be implemented for this area in the near future.

III. Feasibility of the Option

The feasibility of a 2 g/bhp-hr limit has been demonstrated and equipment is commercially available. The economic feasibility is acceptable for new engines since the equipment is somewhat more expensive. Economic feasibility is acceptable for many new engines since the equipment is somewhat more expensive.

Differing Opinion: A number of new and existing engines cannot accept NSCR due to potential durability concerns associated with elevated exhaust temperatures during the needed stoichiometric operation, especially at low or varying loads.

The technical feasibility of a 1 g/bhp-hr limit has been demonstrated in commercial applications. The environmental benefits are significant. New lean burn engines can achieve this emission limit with no add-on controls, and rich burn engines can utilize add-on controls to achieve this limit. The cost is acceptable given the large amounts of gas being compressed by these engines. **Differing Opinion:** The previous statement is subjective and unsubstantiated without supporting data. Need cost benefit analysis to determine acceptable levels. Only the new generation of lean burn engines are capable of meeting a 1 gram performance and then only with AFRC units and near full load.

IV. Background data and assumptions used

The 2 g/bhp-hr limit is based on existing engine technology in conjunction with an NSCR catalyst. The assumptions are that these engines are more than 40 HP and less than 300 HP and that they are natural gas fueled. Further, these engines would be operated with an air fuel ratio controller. The technology for the 1 g/bhp-hr engines larger than 300 HP in natural gas is well established. Although the technology is well established, it will not be commercially available for all engines until 2010. There are large engines available that have a vendor guarantee of emissions approaching 1 g/hp-hr, however, the issue is maintaining emissions at this level on a continuous basis. The new generation lean burn engines in larger sizes will meet 1 g/bhp-hr performance if equipped with AFRC units and operated near full load.

V. Any uncertainty associated with the option

The uncertainty associated with this option is the potential formation of ammonia emissions as a result of add-on controls. Ammonia emissions could worsen the air quality in the region. (See ammonia monitoring mitigation option paper.]

VI. Level of agreement within the work group for this mitigation option TBD.

Differing Opinion: EPA has proposed a 1.0 g/bhp-hr NOx limit for new SI engines, ≥ 500 hp, built on or after July 1, 2010, and for new SI engines, 26-499 hp, built on or after January 1, 2011. While these potential requirements are not expected to be finalized until December 20, 2007, engine manufacturers have already had to initiate engineering work in anticipation of this 1.0 gram requirement. Although a number of lean-burn engines can meet this requirement now, EPA chose the effective dates based upon the fact that other lean-burn engines need the additional time to meet the standards. Cummins has initiated significant work requiring significant resources to modify those engines to achieve the forthcoming 2.0 g/bhp-hr NOx standard. Cummins believes that the incremental benefit offered by a potential pull-ahead of the 1.0 gram standard for larger engines versus the EPA requirement for 2.0 grams NOx soon to be effective followed by the 1.0 gram standard three years later would likely be difficult to justify. Such a pull-ahead, without sound justification, would undermine the substantial work being done by EPA and engine manufacturers in moving toward a national requirement that is to avoid similar, yet different, requirements.

VII. Cross-over issues to the other source groups

The cumulative effects and monitoring groups need to address the concerns with ammonia emissions.

Mitigation Option: Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

This option paper investigates the status of five (1-5) new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

Rich-burn engines with three-way catalysts borrow from the well-developed automobile industry. It is applicable to smaller engines for which lean-burn technology is not available.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

1. Laser Ignition

I. Description of the mitigation option

Overview

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Compared to rich-burn engines, lean burn engines, which are significantly more efficient, require much higher ignition voltage with spark plugs, whereas it takes lower ignition energy with laser system.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air - air at higher pressure requires a higher voltage to make the spark jump the gap, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Air Quality and Environmental Benefits

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Air quality and environmental benefits are difficult to quantify at the current state of development. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure is expected to decrease emissions of NOx because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be virtually eliminated. It is estimated that with laser ignited lean burn engines, the regulated levels of California Air Resources Board NOx levels can be met.

Economic

The primary advantage of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Trade-offs

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

II. Description of how to implement

A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.
B. Indicate the most appropriate agency(ies) to implement: At the current state of development, a research organization is the best agency to develop laser ignition. After its feasibility is shown, an engine manufacturer, working with an ignition system supplier, is best equipped to carry the development through from product research to a commercial product.

III. Feasibility of the option

A. Technical: The primary technical risks are whether sufficiently high light flux can be carried through the fiber optic and whether the fiber optic is sufficiently durable. Laser ignition can be retrofitted to engines that use 18-mm spark plugs.
B. Environmental: If the technical barriers can be overcome, there is little environmental risk to laser ignition.
C. Economic: If the technical barriers can be overcome, the economic incentive for its adoption will depend on whether the engine must operate continuously or whether downtime can be scheduled to change spark plugs. The requirement for continuous operation favors laser ignition, which is expected to have a higher initial cost than spark ignition, but which can eliminate most of the

downtime for changing spark plugs.

IV. Background data and assumptions used TBD.

V. Any uncertainty associated with the option (Low, Medium, High) Medium to High

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

2. Air-Separation Membranes

I. Description of the mitigation option

Overview

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions. However, Poola [***ref Poola paper***] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small, so it will not be considered further.

Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases while particulate emissions increase. Unlike diesel exhaust, the nitrogen enriched air does not contain particulate matter. Manufacturers of heavy-duty diesel engines are concerned that introducing particulate matter from EGR into the engine may cause excessive wear of the piston rings and cylinder liner. Thus, nitrogen enriched air is seen as an alternative to EGR. The published data in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air. [Biruduganti, et al.]

Air Quality and Environmental Benefits

Oxygen-enriched air has only been demonstrated in the laboratory to be beneficial with one type of engine that is considered obsolete. Although the results are encouraging, further testing with a more modern engine would be necessary to confirm the decrease in both NOx and particulate emissions.

The development of oxygen-depleted air is further along and has been demonstrated as an effective alternative to EGR.

Economic

Use of oxygen-depletion membranes might have a higher initial cost than EGR, but would facilitate a longer interval between overhauls. It will have no adverse impact on engine wear or durability; however, EGR at high levels will have reduced engine durability.

Trade-offs

Engine manufacturers are concerned about the abrasive effects of particulate matter on piston rings and cylinder liners and other deleterious effects of EGR [830.pdf]. For the manufacturer the tradeoff is between the initial cost of an oxygen depletion membrane versus the higher frequency of overhauls required with EGR.

II. Description of how to implement

A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.

B. Indicate the most appropriate agency(ies) to implement: The engine manufacturer is the appropriate agency to implement air separation membranes because the primary issue is initial cost versus frequency of overhauls.

III. Feasibility of the option

A. Technical: The technical feasibility of oxygen-depletion membranes has been demonstrated as an alternative to EGR. The technical feasibility of oxygen-enrichment membranes has only been shown in the laboratory for one type of engine. The technical advantages of nitrogen enrichment with membranes have been demonstrated in the laboratory for natural gas and diesel engines.

B. Environmental: The environmental benefits of oxygen-depletion membranes are the same as EGR.

C. Economic: Membrane manufacturers are presently unable to produce enough membranes for widespread implementation of the technology in truck engines. However, the oil and gas industry is a smaller market, which might allow the membrane manufacturers to ramp up their production levels. Because of this situation, the economic feasibility of air-separation membranes is difficult to assess.

IV. Background data and assumptions used

www.enginemanufacturers.org/admin/library/upload/830.pdf

Published technical papers by Argonne National Laboratory and others.

V. Any uncertainty associated with the option (Low, Medium, High)

Low to medium. The technology would receive a "low" uncertainty rating if the availability issue were more settled.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

3. Rich-Burn Engine with Three-Way Catalyst

I. Description of the mitigation option

Overview

Rich-burn engines with a three-way catalyst borrow from the well developed automobile technology using the same type of catalyst. Key to efficient operation of the catalyst is maintenance of slightly lean of stoichiometric operation of the engine. Typically the exhaust oxygen content is maintained in a narrow range not exceeding 0.5% by means of an oxygen sensor in the exhaust stream and closed-loop feedback control of the fuel flow. The oxygen content is enough to catalytically oxidize carbon monoxide and unburned hydrocarbons as it chemically reduces NOx to molecular nitrogen and water. If the engine is operated lean of its desired operating point, NOx reduction efficiency drops off dramatically. If operation is rich, emissions of carbon monoxide and unburned hydrocarbons increase.

It is commercially available as a retrofit for smaller engines. Larger engines are usually operated in the lean-burn mode.

Air Quality and Environmental Benefits

Air quality benefits would be similar to automobiles, where catalytic converters are universally used with rich burn engines.

Economic

Cost of three-way catalyst systems is considered high, but less than that of SCR with a lean-burn engine.

Trade-offs

For small engines (that is, less than 200 BHP) lean burn technology may not be available. Where there is a choice of rich-burn or lean-burn engines, the lean-burn engines offer better fuel economy and more effective, albeit more expensive, overall emissions control via SCR and oxidation catalysts.

II. Description of how to implement

A. Mandatory or voluntary: The use of three-way catalysts will be dictated by the stringency of emissions regulations. Three-way catalysts are sufficiently expensive that they are not likely to be adopted voluntarily.

B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies

III. Feasibility of the option

A. Technical: The technology is commercially available and has been proven effective. Rich-burn engines have higher engine-out NOx emissions, typically about 10-20 g/BHP-hr [830.pdf and reportoct31.doc], than lean-burn engine have. This requires the removal of at least 95% of the NOx if overall emissions are to be reliably reduced to less than 1 g/BHP-hr.

B. Environmental: The State of Colorado estimates that a 3-way catalyst can remove 75% of the NOx, unburned hydrocarbons, and carbon monoxide [reportoct31.doc, although manufacturers of equipment claim that 98-99% of these pollutants are removed.

C. Economic: The State of Colorado estimates that the cost of retrofitting a three-way catalyst system to a rich-burn engine over 250 BHP is $35,000 with annual operating costs of $6,000 [reportoct31.doc].

IV. Background data and assumptions used

http://apcd.state.co.us/documents/eac/cd2/reportoct31.doc

www.enginemanufacturers.org/admin/library/upload/830.pdf

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups TBD

4. Lean-Burn NOx Catalyst, Including NOx Trap

I. Description of the mitigation option

Overview

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical [park.doc.

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published [park.doc and icengine.pdf]. Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel [aardahl.pdf, 2003_deer_aardahl.pdf, and 80905199.htm].

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published [parks01.pdf. A sophisticated engine control is required to make this system work.

Air Quality and Environmental Benefits

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Economic

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm], $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks. Estimates are $10-$20/BHP for stationary engines [icengine.pdf].

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Trade-offs
NOx-trap systems compete with SCR systems. For methane-burning engines, a fuel reformer is required for NOx-trap systems. Fuel reformers are less well developed.

If emissions regulations can tolerate higher NOx emissions, an active lean-burn NOx catalyst might be considered.

I. Description of how to implement

- A. Mandatory or voluntary: The costs of lean-burn NOx catalysts and NOx traps are such than voluntary compliance is unlikely. However, depending on the strictness of the regulations, the user may have a choice of systems.
- B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies.

II. Feasibility of the option

- A. Technical: NOx-trap systems are proven and commercially available for diesel engines. However, they require low-sulfur diesel fuel (less than 15 ppm) to minimize sulfur poisoning of the catalyst. Active lean-burn catalysts are available, but they have a lower NOx reduction efficiency than NOx-trap systems have. Both the lean-burn NOx catalyst and the NOx trap requires a fuel reformer (which can be a catalyst stage upstream of the NOx catalyst) to operate at full efficiency with natural-gas fueled engine.
- B. Environmental: Lean-burn NOx catalysts and NOx-trap catalysts do not have the ammonia slip issue that SCR systems have, but lean-burn NOx catalysts may only partially reduce some of the NOx to nitrous oxide (N2O). The NOx reduction efficiency of NOx traps is similar to that of SCR systems (>90%), but active lean-burn NOx catalysts have a lower efficiency (40-80%).
- C. Economic: Lean-burn NOx catalysts and NOx traps have lower costs than SCR and they avoid the need to purchase and maintain a separate reductant. However, both lean-burn NOx catalysts and NOx traps impose a fuel consumption penalty of 3-7%.

III. Background data and assumptions used

Abstract of Caterpillar paper found at www.emsl.pnl.gov/new/emsl2002/abstracts/park.doc.

www.meca.org.galleries/default-file/icengine.pdf

www.energetics.com/meetings/recip05/pdfs/presentations/aardahl.pdf

www.eere.energy.gov/vehiclesandfuels/pdfs/deer_2003/session10/2003_deer_aardahl.pdf

www.swri.org/epubs/IRD1999/08905199.htm

www.feerc.ornl.gov/publications/parks01.shtml

www.epa.gov/oms/retrofit/retropotentialtech.htm

www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/V2-S4_Final_11-18-05.pdf

IV. Background data and assumptions used None

V. Any uncertainty associated with the option (Low, Medium, High)

NOx traps have a low uncertainty if they are used with low sulfur diesel fuel. They have a medium uncertainty when used with natural gas because of the need to reform the fuel.

Lean-burn NOx catalysts have a medium uncertainty because they may not be able to meet future emissions regulations.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

To be determined. The issue of incomplete NOx reduction that leaves some nitrous oxide (N2O) may be moot if active lean-burn NOx catalysts cannot meet future emissions regulations.

5. Homogeneous-Charge Compression-Ignition (HCCI) Engine

I. Description of the mitigation option

Overview

Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1]

Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option.

II. Description of how to implement

A. Mandatory or voluntary: It is too early to determine whether implementation of this technology will be voluntary or mandatory.
B. Indicate the most appropriate agencies to implement

III. Feasibility of the option

A. Technical: HCCI is in the laboratory stage of development.

B. Environmental: HCCI has the potential of extremely low NOx levels.

C. Economic: HCCI is not sufficiently developed to have proven economic feasibility.

IV. Background data and assumptions used

1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript.

2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc.

3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.

V. Any uncertainty associated with the option (Low, Medium, or High)

HCCI has high uncertainty.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (Please describe the issue and which group.)

Summary
Five technologies are reported: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes have not been tested with lean-burn natural-gas engines.

A rich-burn engine with a three-way catalyst is a mature technology that is borrowed from automobile engines. The three-way catalyst effectively control NOx, unburned hydrocarbon, and carbon monoxide emissions. It requires an exhaust oxygen sensor with a closed-loop control of the fuel so that exhaust oxygen is maintained in a narrow range not exceeding 0.5%. It can be retrofitted to existing engines and is primarily applicable to small engines for which lean-burn combustion is not available. Its primary disadvantages are cost and the inherently lower efficiency of rich-burn engines compared to lean-burn engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

ENGINES: MOBILE/NON-ROAD

Mitigation Option: Fugitive Dust Control Plans for Dirt/Gravel Road and Land Clearing

I. Description of the mitigation option

Fugitive dust emissions from traffic on dirt roads and construction sites are a nuisance and cause frequent complaints. Health concerns related to PM 10 (particulate matter less than 10 microns in size) exposure to high concentrations are breathing, aggravated existing respiratory and cardiovascular disease, lung damage, asthma, chronic bronchitis, and other health problems. Adequate measures could include wind breaks and barriers, water or chemical applications, control of vehicle access, vehicle speed restrictions, gravel or surfacing material use, and work stoppage when winds exceed 20 miles per hour. Activities occurring near sensitive and/or populated areas should receive a higher level of preventive planning. Sensitive receptors would include schools, housing, and business areas.

Economic burdens include increase business costs associated with increased road maintenance, loss of time and productivity associated with work stoppage during high wind days, and increased travel times due to speed restrictions. However, reduced wear on roads and vehicles may be recognized through vehicle speed restrictions.

II. Description of how to implement

A. Mandatory or voluntary: Speed restrictions, regular road maintenance, and construction activity restrictions during high wind days would be mandatory. Road surfacing, wind breaks and barriers and vehicle access control would be voluntary.
B. Indicate the most appropriate agency (ies) to implement: The states, tribal governments, BLM, FS, County, and Industry.

III. Feasibility of the option

A. Technical: The current BLM Road committee is a functional working group with 13 road maintenance units. An industry representative is assigned to each unit to oversee road construction and maintenance activities through a cost-sharing program. BLM law enforcement along with county and state law enforcement could enforce speed restrictions. Industry could make observing speed limits a company policy. Conditions of approval could be added to permitted activities to restrict surface disturbing activities during high wind days. However, industry would prefer the use of other mitigation measures such as road surface treatments (e.g. fresh water or special emulsion) during high wind days.

B. Environmental: The environmental benefits from regular and proper road maintenance, speed restrictions, and surface disturbing activities during high wind days are well documented.

C. Economic: Cost sharing is an important purpose of the current roads committee that is very active and functional work group with regularly scheduled meetings. Funding for speed enforcement is an intricate part and regularly funded operation of BLM, county and state law enforcement.

IV. Background data and assumptions used

1. BLM Gold Book-Surface Operating Standards for Oil and Gas Exploration and Development.
2. Numerous studies on road related erosion issues and standards exist.
3. Studies on excessive road speed and dust development.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option

Four member drafting team support this option

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Use Produced Water for Dust Reduction

I. Description of the mitigation option

This option involves using produced water on roads for dust suppression. Large volumes of water are often produced in conjunction with natural gas production, especially coal bed methane (CBM) production. Wells often produce up to 100-400 barrels/day. CBM produced water quality ranges from nearly fresh water to well above 10,000 ppm total dissolved solids (TDS) and is readily available as an option for road dust suppression. The produced water used for dust mitigation would have to have low TDS and low sodium levels that meet BLM and county standards. Some CBM water meets these standards but not all of it.

Economic benefits could be realized by oil and gas operators in reduced trucking and disposal costs. Likewise, there are associated environmental benefits to this reduced trucking as is outlined in another mitigation strategy. However, the use would be as needed and seasonal (during prolonged dry periods or drought).

Environmental concerns and issues would arise concerning 1) salt build up along roadways, 2) migration of water and associated pollutants off the roadway, 3) impacts to vegetations, 4) salt loading to river systems.

Differing Opinion: Produced water in the Four Corners region contains toxins and therefore should not be used for dust mitigation. The potential environmental concerns include more than just salt-related impacts. Produced waters are of variable quality. Depending on the source, the water may contain high concentrations of constituents other than salts. Data on produced water quality is not widely available to the public. One example of produced water quality, however, was published in a recent report prepared with support from the U.S. Department of Energy. The data show that in the New Mexico portion of the San Juan Basin, there can be elevated concentrations of various metals and other constituents in produced water (in addition to elevated salts – those data not shown).[1]

	McGrath SWD[2]		**Four CBM injection wells[3]**	
All values in mg/L	**Max**	**Min**	**Max**	**Min**
Barium	8.0	0.72	23.9	1.86
Boron	3.0	1.0	2.87	1.6
Bromium	21.8	7.1	15.2	2.4
Copper	0.019	ND		
Chromium	0.035	ND	0.005	
Iron (dissolved)[4]	187	1.1	0.843	0
Selenium	0.080	ND	0.0171	ND

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[1] DiFilippo, Michael N. August, 2004. Use of Produced Water in Recirculating Cooling Systems at Power Generating Facilities. Semi-Annual Technical Progress Report October 1, 2003 to March 31, 2004. Report produced with support from U.S. Department of Energy, Award No. DE-FC26-03NT41906. pp. 12-3.

[2] McGrath Saltwater Disposal Well (SWD): data were from a 30 day random sampling of the SWD well), which was operated by Burlington (now, presumably Conoco).

[3] CBM SWD wells operated by Dugan (Salty Dog 2 and 3 Injection Wells) and Richardson (Turk's Toast and Locke Taber Injection Wells).

[4] According to DiFilippo (page 10), most of the iron comes from aboveground carbon steel pipe used to convey produced water. So, presumably, if water were applied from trucks getting water from the well site, itself, this would not be a concern. If it were water being loaded at the SWD facility, then the iron would be present.

Silver			0.20	ND
Strontium	55	7.2	34.5	1.73
Lead	0.031	ND	0.1	
Total Petroleum Hydrocarbons (TPH)	520	23	17	ND
Zinc			0.298	ND

* ND is non-detected

Produced water may also contain chemical additives put downhole during the drilling, stimulation or workover of the wells. Some of these treatment chemicals, such as biocides, can be lethal to aquatic life at levels as low as 0.1 part per million.[5] It is very difficult to obtain information on the concentrations of treatment chemicals and additives in produced water.

Environmental Justice Issues: Only with the permission of surface owners, municipalities, counties, etc. should produced water be applied to roads. And these entities should be provided with produced water quality information prior to road spreading.

Wyoming requires landowner consent prior to road spreading, which is an important provision to ensure that surface owners have a say in the application of large quantities of water that could affect their property. In Pennsylvania, other jurisdictions, such as municipalities, also have a say with respect to whether or not road spreading is allowed.[6]

II. Description of how to implement

A. Mandatory or voluntary: The use of produced water would be voluntary; however, ultimate approval to do so would be up to the state authority that has primacy over the disposal and use of produced water.
B. Indicate the most appropriate agency(ies) to implement: OCD, BLM, FS.

It may also be necessary to include the states in the implementation of any permitting process related to road spreading since these agencies have the expertise and develop the environmental standards related to surface and groundwater pollution. There is a precedent for involving environment departments. In Wyoming, although the Oil Conservation Commission is responsible for permitting road spreading applications, the operations must also be approved by their Department of Environmental Quality.[7]

III. Feasibility of option

A. Technical: This option is technically feasible, but would require strict controls and monitoring. "Because of the potential for contaminants from the brine to leach into surface or ground waters, the Department of Environmental Protection (DEP) has developed guidelines that must be followed when spreading brine on unpaved roads."[8] It would be advisable for the responsible agencies to develop their

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[5] Argonne National Laboratory. January, 2004. A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas and Coalbed Methane. Prepared for U.S. Department of Energy. Contract No. W-31-109-Eng-38.

[6] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm

[7] Rules and Regulations of the Wyoming Oil and Gas Conservation Commission
Chapter 4, Section 1 http://www.cbmcc.vcn.com/dust.htm
"(nn) Landfarming and landspreading must be approved by the DEQ. Jurisdiction over roadspreading or road application is shared by DEQ and the Commission. . ."

[8] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm

own guidelines or policies to ensure that road spreading practices are carried out in an environmentally sound manner.

<u>B. Environmental:</u> Would require constraints on the allowable TDS and/or SAR content of the water and volumes applied. Baseline field testing for migration/movement would be required to determine if salt build-up is occurring. The use of boom type sprayer (i.e. spreader bars) to prevent pooling and washing off of roadway needs to be highly considered. A responsible party on site during application would be necessary and signage indicating road maintenance being conducted.

Most jurisdictions that allow road spreading do not require chemical data on anything but the salts or dissolved solids (TDS). While TDS includes constituents such as dissolved metals, it does not provide any specific information as to the concentrations of the various metals. Basing the acceptability of using produced water for road spreading on salt content or TDS overlooks the potential impacts from other produced water constituents like metals, hydrocarbons, treatment chemicals and radionuclides (e.g., strontium).

Prior to application of produced water for road spreading purposes, it would be prudent to analyze the water for all potentially harmful constituents. In 2000, there was a case in Garfield County, CO, where a company illegally spread flowback fluids from a workover operation. Samples of the produced water subsequently showed that TDS levels and BTEX were above state drinking water standards.[9]

Prohibit spreading of flowback water. In Pennsylvania, operators are not allowed to spread produced water that main contain treatment chemicals. “Only production or treated brines may be used. The use of drilling, fracing, or plugging fluids or production brines mixed with well servicing or treatment fluids, except surfactants, is prohibited. Free oil must be separated from the brine before spreading.” Essentially, this would mean that the operator would have to wait a certain period of time to allow the majority of the treatment chemicals to flow out of the well before using the produced water for road spreading purposes.

<u>C. Economic:</u> Some operators may see a reduction in hauling and trucking cost associated using produced water for dust control.

IV. Background data and assumptions used

1. Currently produced water is used in some areas for road reconstruction and maintenance, but not for dust reduction. Current levels allowed are 5,000 TDS for maintenance and 18,000 TDS for reconstruction.
2. Could consider higher TDS levels of use with tight restriction on applications methods and timing.
3. Assume applications would be seasonal (during summer dry months)
4. Restricted to main collector road or on all roads with high traffic flow.
5. Need to protect operator’s investment for roadwork already completed.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium uncertainty to environment (water quality and vegetation).

VI. Level of agreement within the work group for this mitigation option.

All members of drafting team support this option.

<u>VII. Cross-over issues to other source groups</u> None at this time.

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[9] Colorado Oil and Gas Information System. 7/6/2000. Notice of Alleged Violation Report. Barrett Resourced Corp. Document No. 850224. http://oil-gas.state.co.us/cogis/NOAVReport.asp?doc_num=850224

Mitigation Option: Pave Roads to Mitigate Dust

I. Description of the mitigation option

This option involves paving roads that service the vast amounts of oil and gas locations in the four corners region. The benefits to air quality would be a significant reduction in dust generated by traffic in the San Juan Basin. Consideration should be given to paving only those collector roads that are located near populated areas and those that received heavy traffic and excessive dust because of high cost of paving. Currently a pilot project is being proposed to use hot emulsified asphalt on reconstructed collector roads. The hot asphalt would be incorporating it into the sandstone caps material using a road re-claimer or blade in an effort to create a durable driving surface.

Economic burdens would be extreme costs to oil and gas operators, federal, state and local governments associated with paving and maintaining a vast network of roads in the San Juan Basin. There would be an immediate increase in traffic accidents associated with an eminent increase in speed associated with paved roads.

II. Description of how to implement

A. Mandatory or voluntary: The construction and road base preparation necessary to properly pave a road would be voluntary
B. Indicate the most appropriate agency(ies) to implement: Industry, OCD, BLM, FS, County, State.

III. Feasibility of option

A. Technical: This option is technically feasible but not practical to pave all roads. Consideration needs to be given to highly travel collector roads and road near heavily populated areas. Portions of heavily travel roads could be considered for paving.
B. Environmental: Would reduce long term dust emissions from vehicle traffic throughout the San Juan Basin but there would be some shorter term increases in emissions associated with asphalt production, paving, and the construction equipment paving the road itself. However, increase accidents and speeding could be drawbacks. Additional law enforcement would be required or re-prioritized workload to curtail speeding.
C. Economic: The cost to prepare, pave, and maintain roads throughout the San Juan Basin are not practical on all roads. Furthermore, the cost to reclaim “paved roads” as part of the restoration process upon well abandonment would be substantial. Consideration could be give to paving only portions of main collector roads, especially in populated areas with heavy traffic.

IV. Background data and assumptions used

1. Pilot project currently proposed. Need to evaluate the effectiveness of using hot emulsified asphalt. Not practical to pave all roads in the San Juan Basin.
2. Restricted to main collector road with heavy traffic, dust problems, and populated areas.
3. Would require addition capital outlay and cost sharing.

V. Any uncertainty associated with the option (Low, Medium, High)

High, due to cost and feasibility.

VI. Level of agreement within the work group for this mitigation option.

Members agree that this option has some merit but in limited areas. Not practical to consider the entire San Juan Basin.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

I. Description of the mitigation option

This mitigation option would involve equipping wells with a variety of technology for the ultimate purpose of being able to decrease traffic to well sites when everything is operating normally. The potential air quality benefits include reduced dust and tailpipe emissions from vehicle traffic. Other potential environmental benefits include reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, the energy companies could benefit by reducing their workforces and the expenses paid for contractors. As this automation may require the electrification of the equipment, the air quality benefits may be offset by emissions elsewhere and of a different nature. Costs for implementing this option may entail the installation of massive electrification systems to power the sensors, radios, and automated valves (vista issues). Additionally, should every well not be checked on a daily basis, there is believed to be a high likelihood that leaks small enough to be undetectable by the automation sensors could go on unabated until the next time the well was visited. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Significant burden would fall on the operator in such a situation. An additional benefit of this option is that once electricity is available at the site, it would increase the feasibility of the electric compressor option included under Stationary RICE.

II. Description of how to implement

The oil & gas industry already uses automation technology where technically and economically feasible. Therefore, this mitigation option would best be implemented in a voluntary manner. As such, agency involvement would not be required.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.

B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions at the well site but increasing emissions during electrification and offsite power generation. (Cumulative Effects Work Group task?)

C. Economic: In some cases the implementation of this technology is economically feasible. In many others it is not. Forced implementation could very well hasten the uneconomic status of a well resulting in the premature abandonment of the well and its hydrocarbon products.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations, hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option

High. The feasibility of implementing this option is very situation specific. It is believed that widespread implementation (75% of wells) is probably not feasible.

VI. Level of agreement within the work group for this mitigation option

Subgroup is in agreement with this option.

Cross-over issues to the other source groups

None at this time.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

I. Description of the mitigation option

This mitigation option would involve enforcing speed limits on unpaved roads in an attempt to reduce dust emissions. The potential air quality benefits include reduced dust emissions from slowed vehicle traffic. Another potential environmental benefit (albeit marginal) is reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, although theoretically less work would be accomplished in the same time period, this impact would be insignificant since the degree of excess over the speed limit is probably not such that implementation of this mitigation strategy would make a significant difference.

A. Public Roads: Enforcement on public roads would be most easily accomplished using local law enforcement agencies. Costs for stepping up enforcement of the speed limits on public roads might include additional funds for increased staff for the local law enforcement agencies.

B. Private Roads: To the extent the unpaved roads are private, the setting and enforcing of speed limits would have to take place in a cooperative agreement between local landowners and energy companies. Since energy companies are not staffed, trained or equipped to be law enforcement agents, this would represent a significant cost shift to the energy companies. Costs for implementing this option on private roads would entail legal review to understand on what basis such" private law enforcement" could take place, the negotiating of agreements with landowners, the posting of signs, and the staffing, training, and equipping of workers to fulfill this function.

C. Assistance: Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production.

II. Description of how to implement

A. On public unpaved roads, enforcement of existing speed limits could be seen as mandatory. The most appropriate agencies to implement are the existing local law enforcement agencies.

B. On private roads, implementation would have to be voluntary as no agency can force a landowner to undertake such a proposition. It is not appropriate for any agencies to get involved in the implementation of this mitigation option. It would be most appropriate for the environmental agencies to simply recognize this as a bona fide emission reduction strategy, and then let the energy company determine where and when to implement such a strategy.

III. Feasibility of the option

A. Technical – Greater enforcement of speed limits on public unpaved roads would be feasible. Establishing and enforcing speed limits on private unpaved roads is feasible but less so.

B. Environmental **-** Assistance from the Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production (how much reduction in speed is needed to have a significant reduction of dust?).

C. Economic **-** Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production.

D. Public Perception – This could be an issue based on the assumption that most people would want any additional funding for police activities to go toward safety/crime issues.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis in this option paper. The governing equations do however include speed as a component.

V. Any uncertainty associated with the option

High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

It is believed that this issue will cross-over to the Other Sources group.
Could the issue described in IV above be addressed by the Cumulative Effects work group?

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

I. Description of the mitigation option

This mitigation option would involve reducing vehicular traffic on unpaved roads (and hence dust production) by centralizing produced water storage facilities and pumping water to them. Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to reduce water hauler traffic. However, unless the produced water could be piped directly to the disposal (injection well) location, the same volume of truck traffic would exist. Therefore, to reap the benefits from this strategy, it would be necessary to either pipe the water directly to the disposal location, or to site the centralized produced water storage facility along a paved road such that the water transporters would not be driving on unpaved roads and creating dust.

Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction (potential), reduced road maintenance, and marginally safer roads. Burdens would fall exclusively on the energy companies. These burdens would include obtaining rights-of-way to lay the needed pipelines, securing the pipe, securing trenching and installation services, and paying crews to make the necessary tie-ins. As much of the produced water in southern Colorado is essentially fresh in nature, heat tracing may be needed to prevent the freezing and bursting of pipes.

Tradeoffs would include the pollutants emitted at the source of the power used to drive the transfer pumps. This power production could be either at the well location (natural gas fired) or at the power plant (electric). Additionally, the dust emissions are currently dispersed over a large area. Centralizing storage would greatly increase tailpipe emissions locally and potentially produce local air quality, noise, and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Additional tradeoffs include the emissions produced at the point of pipe manufacture and the emissions from the trenching operations. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.
B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.
B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).
C. Economic: In some cases the implementation of this technology will be economically feasible. In many others it will not be.

IV. Background data and assumptions used:

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High):

High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced truck traffic vs. laying miles of pipelines and setting many pumps. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

V. Cross-over issues to the other source groups

It is believed that this issue will not cross-over to any other source work group. Assistance from the Cumulative Effects work group on the issue in V. above would be helpful.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

I. Description of the mitigation option

This mitigation option would involve reducing vehicular dust production by covering unpaved roads with rock or gravel. Benefits from this strategy include only dust reduction. Burdens would fall exclusively on the energy companies. These burdens would include obtaining the road material and paying crews to install it. Additionally, the presence of rock on the roads makes snow removal more difficult, and is hard on snow removal equipment. Therefore, road maintenance costs may increase during the winter months. Tradeoffs would include the pollutants emitted during the trucking and installation of the road material. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.

B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative environmental benefit of covering roads with rock (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative emission reductions due to covering the roads with rock (Cumulative Effects Work Group task).

Economic – In some cases the implementation of this technology will be economically feasible. In others it will not be.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option (Low, Medium, High)

High. Assistance from the Cumulative Effects work group would be needed to understand the relative emission reduction benefit from covering lease roads with rock. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue may cross-over to the Other Sources work group.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

I. Description of the mitigation option
This mitigation option would involve setting up a produced water hauler coordinating / dispatch service to route water haulers as efficiently as possible in order to reducing vehicular traffic on unpaved roads (and hence dust production). Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to minimize water hauler traffic. To accomplish this goal, it would be necessary institute a central dispatch concept among all of the water haulers in the area such that (a) only full truckloads are hauled from a given area and (b) the water is hauled to the closest disposal facility possible. Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction, and reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Burdens would fall both on the water hauling service companies and on the water disposal companies. These burdens would include agreements to cooperate (which would include the setting of prices), the purchase of compatible radio equipment, and the implementation of a central dispatch facility. There would be no tradeoffs associated with this strategy. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from optimizing produced water hauling routes.

II. Description of how to implement
This mitigation option could be implemented on a mandatory basis. In order to set fair prices on water hauling and disposal (like taxi cabs), it would be necessary to involve other agencies and potentially special legislation.

The most appropriate agency to implement would be the states' regulatory entity for the oil and gas industry. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

III. Feasibility of the option
Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

Economic – Implementation of this technology should be economically feasible.

IV. Background data and assumptions used
No input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. Assistance from the Cumulative Effects work group would be needed to understand the relative environmental benefit of optimized truck traffic. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups
It is believed that this issue will not cross-over to any other source work group.

Mitigation Option: Use Alternative Fuels and Maximize Fuel Efficiency to Control Combustion Engine Emissions

I. Description of the mitigation option

This option involves the implementation of alternative fuels, ultra low sulfur diesel (15 ppm) and improved fuel efficiency for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001). The air quality benefits include potential reduction of sulfur, greenhouse gases and aromatic compounds throughout the region. Other environmental impacts include a reduction in petroleum consumption and conservation of natural resources.

Economic burdens include the cost of the new alternative fuel/fuel efficient vehicle and cost and availability of the fuel.

There would not be adverse environmental justice issues associated with the implementation of alternative fuels. There is potential for air quality improvements from travels through socio-economically disadvantaged communities with improved fuel efficiency.

Low sulfur diesel can continue to be used in 2006 and older highway vehicles until 2010. Any new 2007 model year highway diesel vehicle will be required to use ultra low sulfur diesel (ULSD). ULSD must be available at retail by October 15, 2006. Terminals should be turned over to ULSD by the end of July. They could consider using ULSD for the non-road equipment too and get even more reductions in PM as well.

II. Description of how to implement

A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to alternative fuel vehicles should be a voluntary program and could be incorporated into the San Juan Vistas or similar program. Likewise the states could adopt tax advantaged strategies under a voluntary program to encourage the adoption of alternative fuels.
B. Indicate the most appropriate agency(ies) to implement**:** NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option

A. Technical: Oil and gas industry have developed a diesel fuel made from natural gas through the Fischer-Tropsch (F-T) process, there are other synthetic liquid fuels and major heavy-duty diesel engine companies are working on engines with reduced NOx and particulate emissions.
B. Environmental: The environmental benefits would primarily be associated with reduced consumption of petroleum resources.
C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Utilize Exhaust Emission Control Devices for Combustion Engine Emission Controls

I. Description of the mitigation option
This option involves the implementation of exhaust emission control devices for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001) such as diesel oxidation catalysts (DOC), diesel particulate filters and/or traps. The air quality benefits include potential reduction of particulate matter and NOx throughout the region.

Economic burdens include the cost associated with the installation and maintenance of the exhaust emission control devices.

There would not be environmental justice issues associated with the implementation of emission controls.

II. Description of how to implement
A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to emission controls should be a voluntary program and could be incorporated into the San Juan Vistas or similar program.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: Technology exists.
B. Environmental: The environmental benefits would primarily be associated with reduced particulates and NOx.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used
1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Exhaust Engine Testing for Combustion Engine Emission Controls

I. Description of the mitigation option

This option involves the implementation of an inspection and maintenance program to determine if emission controls and engines are functioning properly resulting in reduced emissions. Compliance with the standards set in the 2000 Heavy Duty Highway Clean Diesel Trucks and Buses Rule can be tested with an inspections and maintenance testing program. Environmental benefits include potential reduction of sulfur, NOx and particulates throughout the region.

Economic burdens include the cost of the inspection program, equipment, inspectors, and mobile or stationary inspection facilities.

There would not be environmental justice issues associated with the implementation of exhaust engine testing.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory participation would be required.
B. Indicate the most appropriate agency(ies) to implement**:** NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option

A. Technical: Numerous states currently use exhaust emission testing. Details on mobile inspection programs are widely available.
B. Environmental: The environmental benefits would primarily be associated with reduced sulfur, particulates and compliance with Clean Diesel Trucks Rule.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Reduce Trucking Traffic in the Four Corners Region

I. Description of the mitigation option

This option involves implementing various measures to reduce the mileage required to truck fluids or equipment for oil and gas exploration, production, or treating operations. The air quality benefits include increased operating efficiency by 10% which will equate to 10% reduced fuel usage, which results in a net reduction of emissions of NOx by [ ] tons per day, SOx by [ ] tons per day, a reduction in greenhouse gas emissions of [ ] and PM2.5 emissions by [ ] tons per day. Other environmental impacts include reduced dust and noise from the trucks and roads at nearby residences, and reduced unintentional killing of wildlife and livestock that may be killed truck traffic.

Economic burdens include the cost of centralized facilities and systems designed to maximize routing efficiency, which may be partially offset by the benefits to human health of improved air quality and reduction of highway traffic (and traffic accidents) in the region.

There should not be any environmental justice issues associated with the placement of the centralized tank batteries (including produced water tanks, condensate tanks and/or crude oil tanks) in socio-economically disadvantaged communities.
Differing opinion: There are potential health hazards associated with crude oil and condensate tank emissions. Concentrating these facilities in socio-economically disadvantaged communities is an example of environmental injustice.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to maximize routing efficiency and reduce truck trips are envisioned as a "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAs program. Furthermore, the state could adopt tax advantages strategies to allow companies to reduce their taxes by showing reduced emissions from adopting improved routing or operating efficiency. There are currently no mechanisms or rules to require mandatory efficiency standards and this seems implausible as a mandatory approach.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The use of centralized facilities is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced vehicle mileage are well documented.
C. Economic: These options need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used

1. Water hauling is necessary in NM due to the lack of pipeline infrastructure to pipe the fluids directly to SWD facilities; Colorado has a greater use of pipelines.
2. Trucking companies will not react adversely to reduced economics from less vehicle miles.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option General agreement among drafting team members that this is viable and probable.

VII. Cross-over issues to other source groups None at this time.
Differing opinion: Some indication by the Cumulative Effects group of the potential emissions reduced would be helpful.

ENGINES: RIG ENGINES

Mitigation Option: Diesel Fuel Emulsions

I. Description of the mitigation option

Diesel Fuel Emulsions:

- This option, which is an EPA verified retrofit technology, reduces peak engine combustion temperatures and increases fuel atomization and combustion efficiency.
  Differing opinion: The EPA study only looked at the "summer" blend of diesel emulsion. There is no data available to evaluate neither the compatibility with winter temperatures nor the emissions effects at winter temperatures.
- It is accomplished by using surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture while ensuring that the water does not contact metal engine parts.
- Air quality benefit:

	% Reductions[2, 3]			
Non-Road [1]	PM	CO	NOx	HC
0-100 hp	23	(35)	19	(99)
100-175 hp	17	13	17	(80)
175-300 hp	17	13	19	(73)
>300 hp	17	13	20	(30)

1. Estimate using 2D fuel, <500 ppm sulfur.
2. (##) indicates an increase
3. Based on verification results supplied to EPA by Lubrizol for PuriNOx emulsion.
   Differing Opinion: CARB's verified NOx reductions were lower (14%) than EPA's as shown in the above table. This suggests a need for a more extensive review prior to finalizing this option.

- Can be used in conjunction with a diesel oxidation catalyst to reduce HC and CO emissions and further reduce PM.
- Emission control performance is better in lower load/lower speed applications.
- Emulsions have about a 12-month shelf life.
- Typically experience a 20% power loss when operating at maximum engine horsepower. The power loss is potentially a fatal flaw in this method. Most rig engines are sized for the maximum load expected and would have to be refitted with larger engines to handle the equivalent maximum loads.
- Will expect a 15% increase in fuel consumption for equipment operating on fuel with emulsion additive. [This will increase SO2 emissions by 15%. The mass will depend on the sulfur content of the fuel. It will also increase fuel delivery truck emissions by 15% along with road dust emissions due to fuel hauling by 15%.
- Not compatible with optical or conductivity-type fuel sensors, water absorbing water separators, water absorbing fuel filters, or centrifugal style water separators.
- Engine must be run for at least 15 minutes every 30 days.
- Incremental cost increase of $0.10 to 0.20 per gallon.
  Differing opinion: The increased fuel cost on top of the 15% increase in fuel consumption makes this a very expensive option. For a "typical" 16 day Wyoming Green River Basin well using 19,816 gallons of diesel, the 15% fuel penalty would represent about $6,000 additional fuel cost and the average premium ($0.15/gal) would represent about $3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about $9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system. The incremental cost per gallon needs to be updated and verified – the cost quoted dates

to the original study date. Installation of oxidation catalyst to control hydrocarbon and CO emissions would add additional cost and complexity to an already cost prohibitive option.

- Requires mixing of fuel with emulsion and a storage unit for the emulsion and or mixed fuel. Some burden on technicians to properly operate and mix some simple equipment.

II. Description of how to implement

This voluntary option would be relatively simple using EPA verified retrofit technology. Some analysis is required to ensure that duty cycle (how long will engine and fuel be idle) and ambient temperatures are compatible with the emulsion product. Storage tanks and some training and capable technicians will be required to put into operation the relatively simple mixing equipment.
Differing opinion: The power penalties, incremental mixing and storage equipment, and increased technical knowledge necessary make this option do-able, but not necessarily simple.

III. Feasibility of the option

A. Technical: Technically this is one of the simplest options available.
B. Environmental: Fuel emulsion has potential for increased carbon monoxide and hydrocarbon emissions, but this downside could be overcome by use of a diesel oxidation catalyst. One additional issue with the emulsion option is that if the emulsion is no longer purchased or used the emission benefit goes away, in comparison to permanent exhaust treatments or improved engines or hardware.
C. Economic: There would be capital cost for emulsion and/or mixture storage and ongoing incremental cost per gallon.
Differing opinion: This option should be characterized as an expensive one. Using a “typical” 16 day Wyoming Green River Basin well using 19,816 gallons of diesel the 15% fuel penalty would represent about $6,000 additional fuel cost and the average premium ($0.15/gal) would represent about $3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about $9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system.

IV. Background data and assumptions used

As an EPA verified retrofit, the data and assumptions associated with this option have been well evaluated and considered.
Differing opinion: The evaluation of applicability in cold weather needs to be done.

V. Any uncertainty associated with the option (Low, Medium, High)

Low uncertainty as this is a verified, simple retrofit.
Differing opinion: Given the high apparent cost, no evaluation in cold weather, different reduction percentages from separate evaluations, and complexity, this option should not be considered low uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None at this time.

Mitigation Option: Natural Gas Fired Rig Engines

I. Description of the mitigation option

Install natural gas fired engines on rigs in the Four Corners region.

Benefits

- Air Quality - Natural gas engines emit less and NOx,
  - ~ 85% reduction of NOx vs. Tier I engines.
    Differing opinion: Given the variable load (and often low load) on drilling rig engines, the "best" lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
  - ~ 91% reduction of NOx vs. Tier 0 engines
    Differing opinion: Given the variable load (and often low load) on drilling rig engines, the "best" lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
  - Natural gas engines emit less particulate matter (PM) on a larger percent reduction basis than the NOx percentages above.
- Cost Savings?
  - If the natural gas fuel source is in close proximity and little piping is required, its use may be less expensive than diesel, which is currently hauled to the rig.
    Differing opinion: On a purely fuel basis this may be true without considering the retrofit costs.
  - Savings in fuel cost is dependent on product price.

Tradeoffs

- CO levels increase with natural gas usage, ~ 175%

Burdens

- Fuel Source
  - A natural gas fuel source sufficient to power the rig engines may not be readily available at every site.
  - Installation of piping to transport the natural gas may increase safety risks for workers and may potentially require right-of-way that can significantly delay projects (months to years).
  - Natural gas usage may require mineral owner approval, metering and appropriate allocation potentially resulting in permitting delays and increased administrative support
  - Fuel supply needs careful tuning and monitoring due to varying amounts of produced water that may be present. Also impacted by variations in fuel quality in the different areas and formations of a field. Could also require the installation of a dehydrator if gas is wet and the field uses a central dehydration system.
  - Engine size must increase to achieve an equivalent horsepower yield. For example a Cat 3512 diesel would have to be replaced with a Cat 3516 natural gas engine to get approximately the same horsepower.
- Rig Operations
  - Slower power response and less torque requires learning curve on rigs
  - Not well suited for Mechanical Rigs – Electric rigs are preferred. Information from natural gas fueled engine rigs in Wyoming indicates that a "load bank" is required due to the slower response of the engines to power demand.
- Cost
  - Initial Capital Investment – up to 1.2 MM$ / Rig for retrofit

  - If the natural gas fuel source is distant or not available for other reasons, the associated piping or use of LNG may be significantly more expensive than diesel.
    Differing opinion: LNG is not a viable fuel – it is not readily available, requires refrigerated storage, and requires "re-gas" equipment. Conversion to natural gas fuels essentially limits the utility of a particular rig to just those instances where gas is available.
- Availability
  - Engine availability is limited

II. Description of how to implement

A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement**:** None

III. Feasibility of the option

A. Technical: A natural gas fired rig engine is currently being utilized in Wyoming in the Jonah Field indicating that the technology works. However, the Jonah field is significantly different from the San Juan Basin enabling easier access to natural gas as a fuel source. The wells in the Jonah Field are more closely spaced (10 acre vs. 80 acre) and deeper allowing for the directional drilling of several wells from a single well pad and close proximity to currently producing wells.

B. Environmental: Installation of natural gas fired engines on new rigs will significantly reduce NOx emissions for those rigs, but may result in other environmental impacts, including an increase in CO emissions and potential land disturbance related to installation of natural gas pipelines to deliver the fuel.

C. Economic: In some cases where a natural gas fuel source is nearby, fuel costs may be lower than for diesel. In other cases, where access to natural gas can only be obtained by installing a large amount of pipe that potentially requires a right-of-way or by using LNG, the costs may be significantly higher. Conversion to natural gas fired engines essentially limits the use of a rig to only those instances where gas is available. The conversion/retrofit costs are high.
Differing opinion: See LNG comments above.

IV. Background data and assumptions used

Utilized Encana data obtained from Ensign 88 – Natural Gas Rig (2 3516 LE Natural Gas Engines on 1200 KW Generators)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Selective Catalytic Reduction (SCR)

I. Description of the mitigation option

Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) is the process where a reductant (typically ammonia or urea) is added to the flue gas stream and is absorbed onto the catalyst (typically vanadium or zeolite) enabling the chemical reduction of NOx to molecular nitrogen and water. Diesel engines typically have unconsumed oxygen in the exhaust, which inhibits removal of oxygen from the NOx molecules. To remove the unconsumed oxygen, the catalyst decomposes the reductant causing the release of hydrogen, which reacts with the oxygen. This creates local oxygen depletion near the catalyst allowing the hydrogen to also react with the NOx molecules to form nitrogen and water.

Benefits

- NOx emission reductions of 80-90% are achieved. NOx emission reductions of up to 80-90% are achievable.
- Potential to reduce hydrocarbon, hazardous air pollutant, and condensable particulate matter (PM) emissions based on emissions tests.
- Technology is available currently.
- SCR systems designed primarily to reduce NOx have been designed with PM filtering capabilities.

Tradeoffs

- Ammonia Slip

The SCR process requires precise control of the ammonia injection rate. An insufficient injection may result in unacceptably low NO_x conversions. An injection rate that is too high results in release of undesirable ammonia to the atmosphere. These ammonia emissions from SCR systems are known as *ammonia slip*. Ammonia slip will also occur when exhaust gas temperatures are too cold for the SCR Reaction to occur. Ammonia slip can potentially be controlled by an oxidation catalyst installed downstream of the SCR catalyst. Diesel oxidation catalysts are often used downstream of NOx catalysts for ammonia reduction.

Burdens

- Minimum and maximum temperature ranges limit the effectiveness of the SCR system.
  - The SCR system requires a minimum exhaust temperature of 572°F (300°C) and maximum of 986°F (530°C) for NOx reduction to occur (optimal range).
- The SCR systems had faults and system errors that can shut the urea injection system off.
  - ENSR testing had problems with the NO2 measuring cells that had multiple high and low pressure and measurement alarms.
- The SCR system needs operator attention.
  - The SCR system needs to be tuned to the engine operating cycle. This requires running the engine through a simulation of the operating cycle of the machine it will be fitted to (engine mapping).
  - Typically SCR catalysts require frequent cleaning even with pure reductants, as the reductant can cake the inlet surface of the catalyst while the exhaust gas stream temperature is too low for the SCR reaction to take place.
- Potential for ammonia slip
- Cost (Retrofit)
  - Capital Expenditure Costs - ~$130,000 / new SCR unit

- Operating Expenditure Costs - ~$143,000 / year / unit 1
- Costs extrapolated out over a 10-year period would equate to **$1.56 MM / engine equipped.**
- Need for reductant (NH3) adds to the engine operating cost (in the range of 4% of the equipment operating fuel cost).

Non-Selective Catalytic Reduction (NSCR)
NSCR is not applicable to diesel engines.

II. Description of how to implement

A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.
.
B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The technology is available and effective in reducing NOx emissions.
B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.
C. Economic: Capital costs associated with a new engine with SCR or installation of retrofit SCR are feasible. Additional costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used

Utilized information from ENSR Presentation - *Technology Demonstration – Selective Catalytic Reduction (SCR) and Bi-Fuels Implementation on Drill Rig Engines*

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – It is clear that SCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option

The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.
EPA has SCR listed as a Potential Retrofit Technology for diesel engines.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Selective Non-Catalytic Reduction (SNCR)

I. Description of the mitigation option

Selective Non-Catalytic Reduction (SNCR) is a post-combustion treatment in which ammonia is injected into the flue gas stream. The ammonia reacts with the NOx compounds, forming nitrogen and water. In order for this technique to be effective, the ammonia must be injected at a proper temperature range within the stack and must be in the proper ratio to the amount of NOx present. The reduction reaction at temperatures ranging from 925 – 1125ºC does not require catalysis and can achieve 40% NOx control. More modest NOx reductions are reported in the 725 - 925ºC range.
Differing Opinion: These are very high temperatures and much greater than the temperatures in diesel engine exhaust. For example, the data sheet for a Cat 3512 diesel rig engine shows a “highest” exhaust temperature of ~792 degrees F. Based on the degradation in performance reported in the 725 – 925 degrees C it probably would have very little effect at the exhaust temperatures from rig engines. This technology is really tested for very high temperature boilers only – not engines.

Benefits

- NOx emission reductions of ~40% (range 20-55%) are achieved in optimal temperature range.
- Avoids the expense of a catalyst.
- Technology is available currently.

Tradeoffs

- Ammonia Slip – 10 ppm ammonia slip is considered reasonable for SNCR. 10 ppm represents about 16 tons/yr of ammonia from a single fully loaded Cat 3512 engine. Given that most rigs have two or more engines it is not much of a stretch to have very significant ammonia emissions with the number of rigs running in the basin. This amount of ammonia may enhance secondary particulate formation with consequent effects on PM 2.5 (health based) and visibility (perception based).

Burdens

SNCR tends to have high operating costs - cost is estimated at $600 - $1300/ton
Mobile source engines (rig engines) are usually not a good candidate for SNCR because typical operating temperatures are below the levels needed for effective operation.

II. Description of how to implement

A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.
B. Indicate the most appropriate agency(ies) to implement: Colorado Department of Public Health and Environment (CDPHE), New Mexico Environment Department (NMED).

III. Feasibility of the option

A. Technical: The technology is available and effective in reducing NOx emissions.
Differing Opinion: There is no available data indicating applicability to engines or much lower temp operation. This option should be considered as non-feasible.
B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.
C. Economic: Costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used

State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines – State of New Jersey, Department of Environmental Protection, Division of Air Quality

V. Any uncertainty associated with the option

Medium – SNCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option

The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.

VII. Cross-over issues to the other source groups

Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards

I. Description of the mitigation option

In short this option would require the use of engines that at minimum meet EPA Tier 2 non-road on a fleet average basis and that all newly installed engines would meet the most current EPA standard (Tier 2 through 4).

In 1998, EPA adopted more stringent emission standards ("Tier 2" and "Tier 3") for NOx, hydrocarbons (HC), and PM from new nonroad diesel engines. This program includes the first set of standards for nonroad diesel engines less than 50 hp (phasing in between 1999 and 2000), phases in more stringent "Tier 2" emission standards from 2001 to 2006 for all engine sizes, and adds more stringent "Tier 3" standards for engines between 50 hp and 750 hp from 2006 to 2008.

In June 2004, EPA adopted additional nonroad diesel engines emission standards. These standards are known as "Tier 4." This comprehensive national program regulates nonroad diesel engines and diesel fuel as a system. New engine standards will begin to take effect in the 2008 model year, phasing in over a number of years.

The pertinent regulations are as follows:

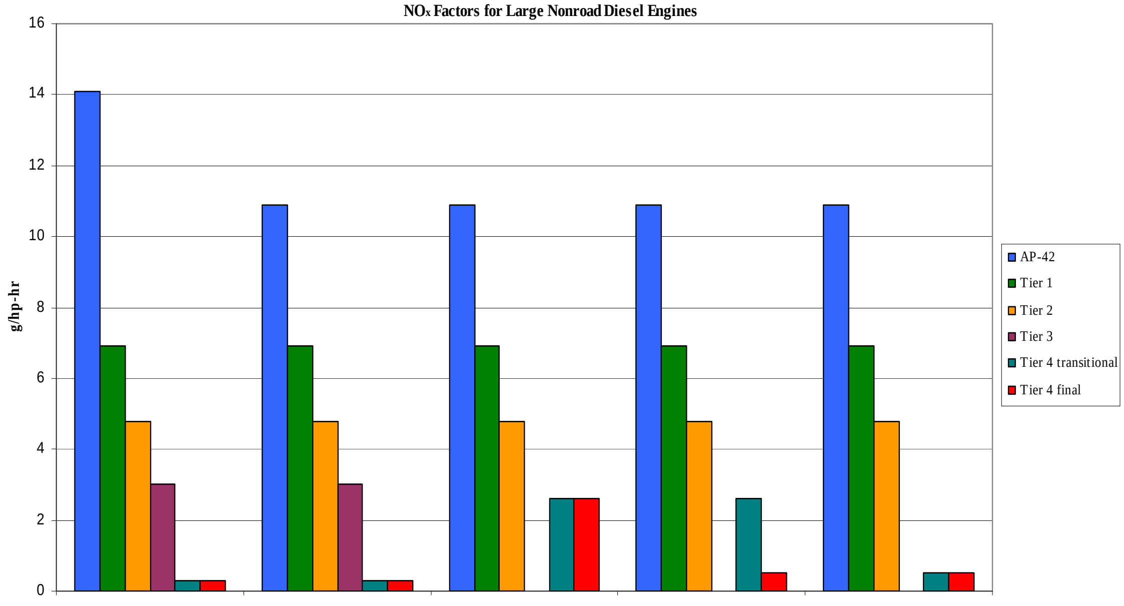
Clean Air Nonroad Diesel - Tier 4 Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, 69 FR 38957, June 29, 2004

Tier 2 and Tier 3 Emission Standards - Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines, 63 FR 56967, October 23, 1998

Drill rig engines would be considered "non-road engines" because of the definition of non-road engine in 40 CFR 1068.30 (1)(iii) and (2)(iii) – assuming the rig moves more often than every 12 months.

These non-road diesel standards do not apply to existing non-road equipment. Only equipment built after the start date for an engine category (1999- 2006, depending on the category) is affected by the rule.

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]



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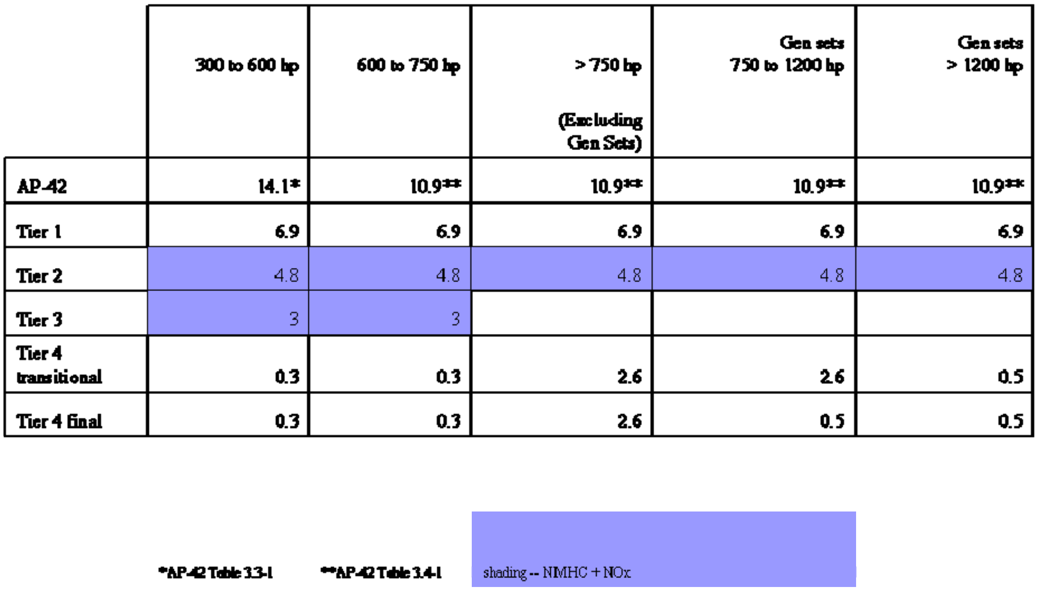
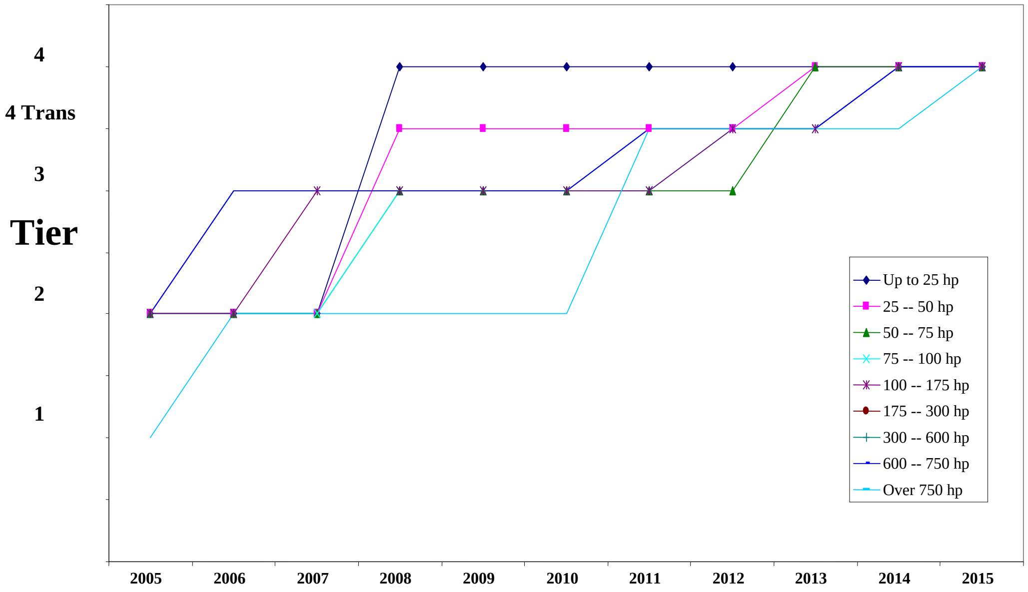


	300 to 600 hp	600 to 750 hp	> 750 hp (Excluding Gen Sets)	Gen sets 750 to 1200 hp	Gen sets > 1200 hp
AP-42	14.1*	10.9**	10.9**	10.9**	10.9**
Tier 1	6.9	6.9	6.9	6.9	6.9
Tier 2	4.8	4.8	4.8	4.8	4.8
Tier 3	3	3			
Tier 4 transitional	0.3	0.3	2.6	2.6	0.5
Tier 4 final	0.3	0.3	2.6	0.5	0.5

*AP-42 Table 3.3-1 **AP-42 Table 3.4-1 shading -- NMHC + NOx

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]

Effective Dates of Tier Standards, Nonroad Diesel Engines, by Horsepower



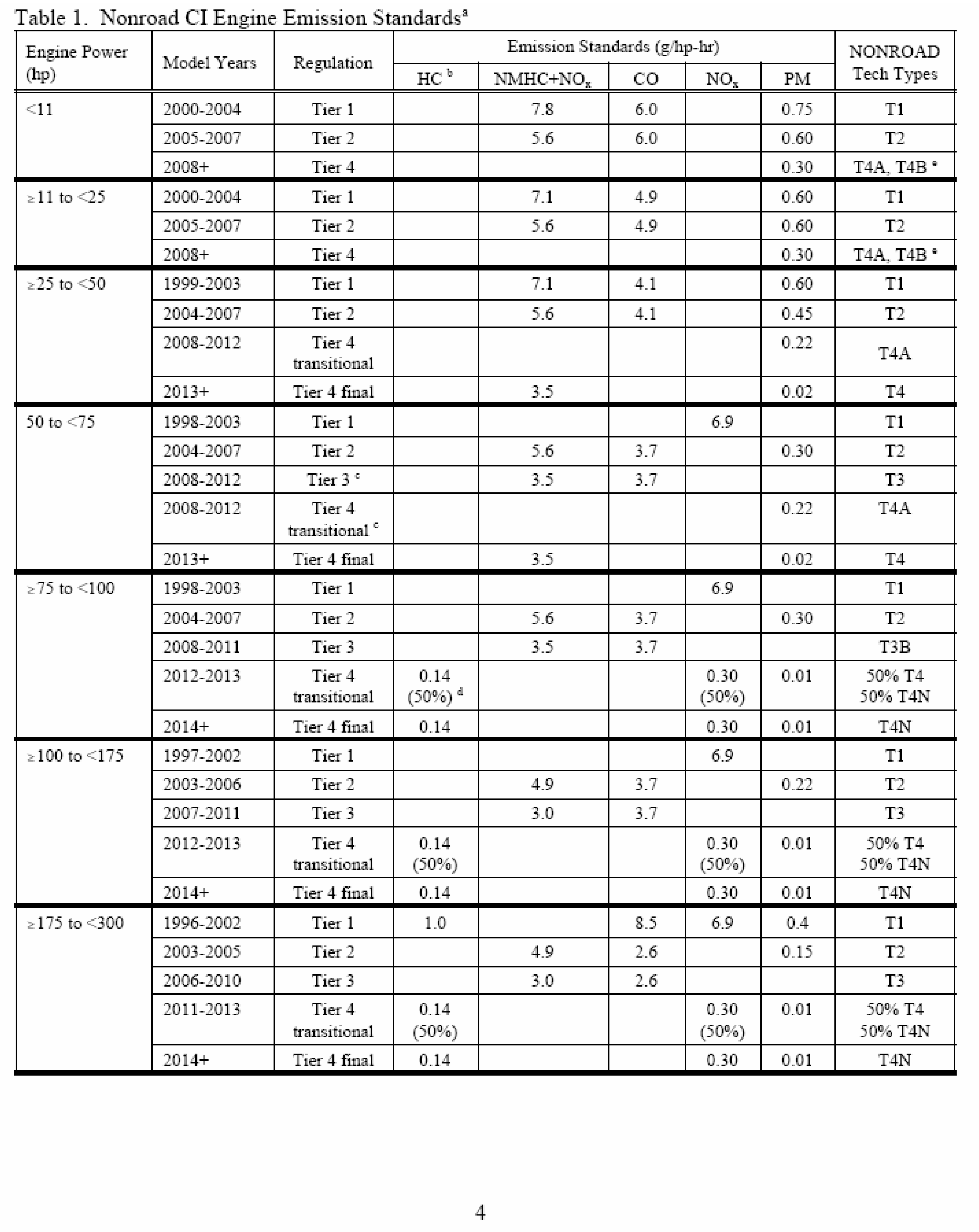
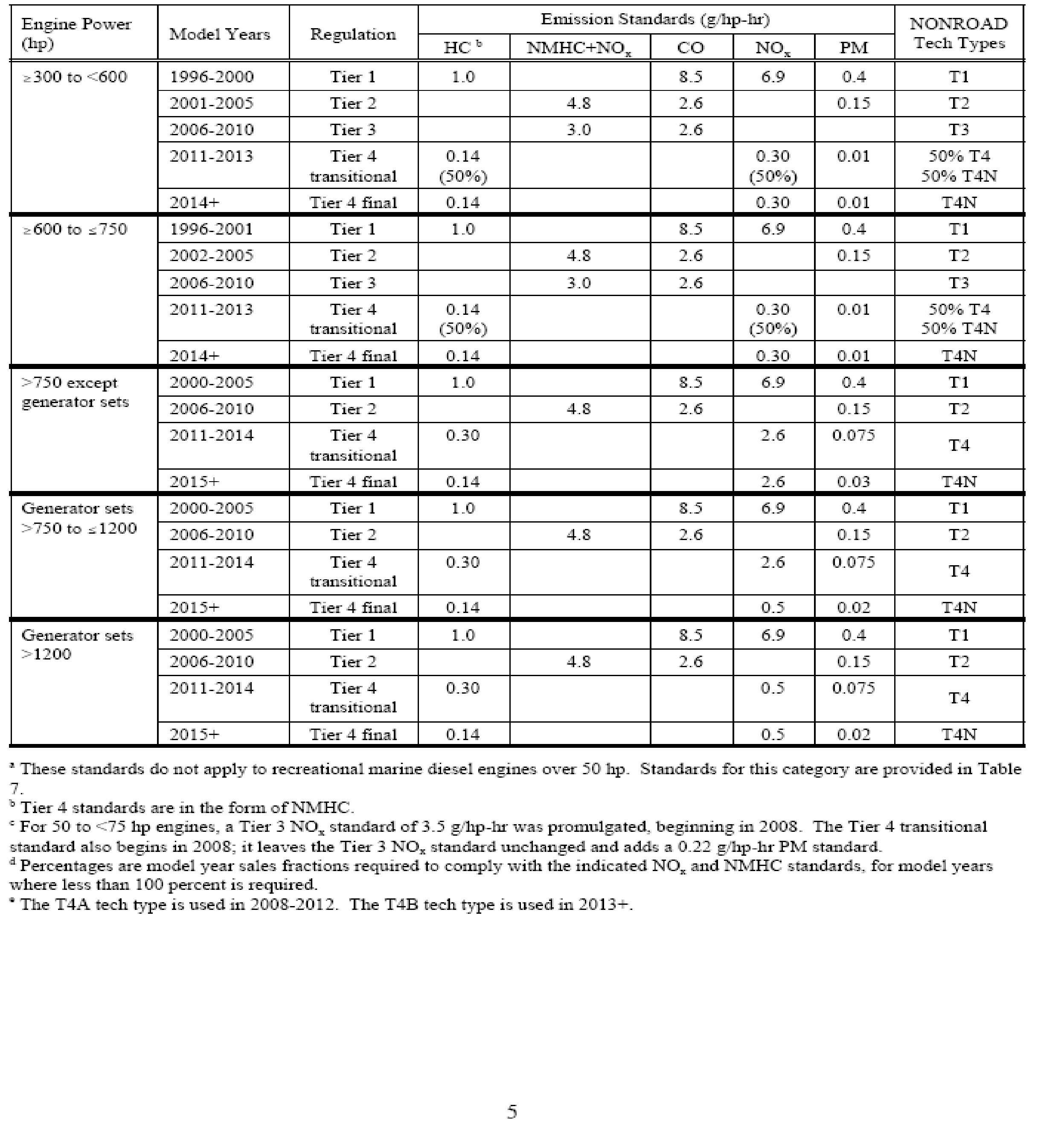


Table 1. Nonroad CI Engine Emission Standards[a]

Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC[b]	NMHC+NO_x	CO	NO_x	PM	
<11	2000-2004	Tier 1		7.8	6.0		0.75	T1
	2005-2007	Tier 2		5.6	6.0		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B[e]
≥11 to <25	2000-2004	Tier 1		7.1	4.9		0.60	T1
	2005-2007	Tier 2		5.6	4.9		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B[e]
≥25 to <50	1999-2003	Tier 1		7.1	4.1		0.60	T1
	2004-2007	Tier 2		5.6	4.1		0.45	T2
	2008-2012	Tier 4 transitional					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
50 to <75	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2012	Tier 3[c]		3.5	3.7			T3
	2008-2012	Tier 4 transitional[c]					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
≥75 to <100	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2011	Tier 3		3.5	3.7			T3B
	2012-2013	Tier 4 transitional	0.14 (50%)[d]			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥100 to <175	1997-2002	Tier 1				6.9		T1
	2003-2006	Tier 2		4.9	3.7		0.22	T2
	2007-2011	Tier 3		3.0	3.7			T3
	2012-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥175 to <300	1996-2002	Tier 1	1.0		8.5	6.9	0.4	T1
	2003-2005	Tier 2		4.9	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N



Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC[b]	NMHC+NO_x	CO	NO_x	PM	
≥300 to <600	1996-2000	Tier 1	1.0		8.5	6.9	0.4	T1
	2001-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥600 to ≤750	1996-2001	Tier 1	1.0		8.5	6.9	0.4	T1
	2002-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
>750 except generator sets	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			2.6	0.03	T4N
Generator sets >750 to ≤1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N
Generator sets >1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			0.5	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N

[a] These standards do not apply to recreational marine diesel engines over 50 hp. Standards for this category are provided in Table 7.

[b] Tier 4 standards are in the form of NMHC.

[c] For 50 to <75 hp engines, a Tier 3 NO_x standard of 3.5 g/hp-hr was promulgated, beginning in 2008. The Tier 4 transitional standard also begins in 2008; it leaves the Tier 3 NO_x standard unchanged and adds a 0.22 g/hp-hr PM standard.

[d] Percentages are model year sales fractions required to comply with the indicated NO_x and NMHC standards, for model years where less than 100 percent is required.

[e] The T4A tech type is used in 2008-2012. The T4B tech type is used in 2013+.

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II. Description of how to implement

A. Mandatory or voluntary
Compliance with these regulations is required for new and rebuilt engines after the specified deadlines. The Four Corners Task Force is studying the potential for quicker implementation of the standards based on a voluntary agreement to either retrofit existing engines to meet the Tier 2 through Tier 4 standards or use of new Tier 2 through Tier 4 compliant engines.

B. Indicate the most appropriate agency(ies) to implement

EPA implements the non-road engine regulations nationally by certifying engine manufacture test results, but state regulatory agencies would be involved in any agreements for accelerated implementation of the standards in the Four Corners area.

III. Feasibility of the option

A. Technical

Some engine industry authorities indicate anecdotally that the supply of the new, cleaner engines may fall short of the demand for them particularly in the oil and gas industry.

In 1998, EPA adopted more stringent emissions standards for nonroad diesel engines. In that rulemaking, EPA indicated that in 2001 it would review the upcoming Tier 3 portion of those standards (and the Tier 2 emission standards for engines under 50 horsepower) to assess whether or not the new standards were technologically feasible. EPA drafted a technical paper with a preliminary assessment of the technological feasibility of the Tier 2 and Tier 3 emission standards - http://www.epa.gov/nonroad-diesel/r01052.pdf

In this assessment EPA determined that the standards were feasible with technologies such as the following:

Charge Air Cooling - Air-to-air or air-to-water cooling at intake manifold reduces peak temperature of combustion. (Controls NOx)

Fuel Injection Rate Shaping & Multiple Injections - Controls fuel injection rate, limiting rate of increase in temperature & pressure. (Controls NOx)

Ignition Timing Retard - Delays start of combustion, matching heat release with power stroke. (Controls NOx)

Exhaust Gas Recirculation - (1) Reduces peak cylinder temperature, (2) dilutes O_2 with inert gases, (3) dissociates CO_2 & H_2O endothermic. (Controls NOx)

B. Environmental

The Tier 2 and 3 standards will reduce emissions from a typical nonroad diesel engine by up to two-thirds from the levels of previous standards. By meeting these standards, manufacturers of new nonroad engines and equipment will achieve large reductions in the emissions (especially NOx and PM) that cause air pollution problems in many parts of the country. EPA estimates that by 2010, NOx emissions nationally will be reduced by about a million tons per year because of the Tier 2 and 3 standards.

When the full inventory of older nonroad engines are replaced by Tier 4 engines, annual emission reductions nationally are estimated at 738,000 tons of NOx and 129,000 tons of PM. By 2030, 12,000 premature deaths would be prevented annually due to the implementation of the proposed standards. EPA estimates that NOx emissions from these engines will be reduced by 62 percent in 2030.

C. Economic

EPA estimates the costs of meeting the Tier 2 and 3 emission standards are expected to add well under 1 percent to the purchase price of typical new non-road diesel equipment, although for some equipment the standards may cause price increases on the order of two or three percent. The program is expected to cost about $600 per ton of NOx reduced, which compares very favorably with other emission control strategies.

The estimated costs for added emission controls for the vast majority of equipment was estimated at 1-3% as a fraction of total equipment price. For example, for a 175 hp bulldozer that costs approximately $230,000 it would cost up to $6,900 to add the advanced emission controls and to design the bulldozer to accommodate the modified engine.

EPA estimated that the average cost increase for 15 ppm sulfur diesel fuel will be seven cents per gallon. This figure would be reduced to four cents by anticipated savings in maintenance costs due to low sulfur diesel.

IV. Background data and assumptions used (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

The Cumulative Effects group could assess how much air quality improvement would be realized from implementation of the Tier 2 through Tier 4 standards by a specified percent of rig engines in the Four Corners area, by timeframes specified in regulation or some accelerated schedule. The group could also address the number of days of visibility improvement, and the reduced flux of Nitrogen deposition.

V. Any uncertainty associated with the option (Low, Medium, High)

Low, these diesel engine standards must be met nationally by the specified dates. The primary uncertainty raised so far is related to supply of new engines sufficient to meet demand. EPA has studied the technological feasibility of the Tier 2 and Tier 3 emission standards and has determined that they are feasibility [see http://www.epa.gov/nonroad-diesel/r01052.pdf]

VI. Level of agreement within the work group for this mitigation option N.A. for complying with national regulations.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

All new “non-road” diesel engines used in the Four Corners area will have to comply with these regulations.

Mitigation Option: Interim Emissions Recommendations for Drill Rigs

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

NOx emissions from drill rigs are significant on a year round basis and should be reduced by a requirement that rig engines meet Tier 2 standards.

- NOx emissions from rigs contribute to visibility degradation
- This recommendation is consistent with EPA Region 8's oil and gas initiative and recent Wyoming DEQ recommendations
- The requirement may be impractical for BLM to enforce

States should analyze potential initiatives to achieve emissions reductions from these sources to reduce deposition, the cumulative impacts to visibility, and to ensure compliance with the NAAQS and PSD increments.

II. Description of how to implement

NOx emission limits determined by Tier 2 would be mandatory for new rigs and voluntary for existing equipment. The agencies to enforce this would be BLM and the New Mexico and Colorado departments of environmental quality.

III. Feasibility of the Option

The feasibility of Tier 2 requirements for new rig engines has been demonstrated in commercial applications. The environmental benefits include PM and NOx reductions. The economic feasibility depends on using the technology with new rigs. The cost for replacement of an existing engine would be high since there might be no market for the used engine.

IV. Background data and assumptions used

The technology for rig engine upgrade to Tier 2 standards is based on the requirement to use Tier 2 certified diesel engines on new rigs. Under certain circumstances, upgrades might be required on older rigs as well.

V. Any uncertainty associated with the option

Tier 2 engines are currently being manufactured, but some uncertainty exists about the effectiveness of add-on controls to meet Tier 2 levels for existing rig engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

None.

Mitigation Options: Various Diesel Controls

Duel Fuel (or Bi-fuel) Diesel and Natural Gas; Biodiesel; PM Traps; Free Gas Recirculation; Fuel Additives; Liquid Combustion Catalyst; Lean NOx Catalyst; Low NOx ECM - Engine Electronic Control Module (ECM) Reprogram; Exhaust Gas Recirculation (EGR)

I. Description of the mitigation options

Duel fuel (or Bi-fuel) diesel and natural gas

This system allows engines to run on a blend of diesel and natural gas fuels. The systems consist of an air to fuel (AFR) controller and a fuel mixing chamber. The AFR constantly adjusts the fuel to air mixture being delivered to the piston chambers and optimizes the stoichiometric relationship in order to balance the NOx and CO emissions. The mixing chamber establishes the diesel to natural gas mixing ratio. This system is being tested on drill rig diesel engines in the Pinedale, WY area. There are preliminary results based on tests of three engines (Cat 398 & 399) Pros: Operators reported that rig engine fuel costs were reduced by ~ $700 per day, requires minimal engine modification, and has a small footprint. Cons: Does not conclusively reduce NOx, increases CO and HC emissions, and the system needs frequent oversight to ensure operation.

Biodiesel

Biodiesel fuel stock comes from vegetable oil, animal fats, and waste cooking oils. Biodiesel can be blended at different percentages up to100% (typically 5 – 20%). Biodiesel at a 20% blend can reduce PM mass emissions by up to 10%, reduce HC and CO up to 20%, and may slightly increase NOx emissions. Use of biodiesel requires little or no modification to fuel system or engine. Cold temperatures require special fuel handling such as additives or heating fuel system. EPA listed “verified retrofit technology.”

PM Traps

Diesel particulate filters (DPFs) collect or trap PM in the exhaust. DPFs consist of a filter encased in a steel canister positioned in the exhaust system. DPFs need a mechanism to remove the PM (regeneration or cleaning) and to monitor for engine backpressure. DPFs types have different reduction capabilities and applications. DPFs can be used in conjunction with catalysts (catalyst based (CB) DPFs) to obtain the most effective PM control for a retrofit technology. CB-DPFs can have over 90% PM mass reduction and over 99% carbon based PM reduction. CB-DPFs can also control CO and HC resulting in near elimination of diesel smoke and odor.

Flow through filters (FTFs), or partial flow filters, use a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil. FTFs are a relatively new technology. FTF can be catalyzed or used in combination with Diesel Oxidation Catalysts (DOCs) or Fuels Borne Catalysts (FBCs). PM reduction efficiencies range from 25 to over 60% depending on the type of technology and duty/test cycle. FTFs have the potential for greater application than conventional DPFs. Some designs can be used on engines fueled with < 500 ppm sulfur fuel but efficiency decreases. Has the potential for use on older engines, but high PM levels can overwhelm even a FTF system. Adequate exhaust temperatures are needed to support filter regeneration.

Diesel exhaust PM traps are EPA listed “verified retrofit technology.”

Free Gas Recirculation

Crankcase emissions from diesel engines can be substantial. To control these emissions, some diesel engine manufacturers make closed crankcase ventilation (CCV) systems, which return the crankcase blow-by gases to engine for combustion. CCV systems prevent crankcase emissions from entering the atmosphere. Aftermarket open crankcase ventilations (OCV) are available which provide incremental improvements over engines with no crankcase controls, but they still allow crankcase emissions to be released into the atmosphere. A retrofit CCV crankcase emission control (CCV) system has been introduced and verified for on-road applications by both the U.S EPA and CARB. Crankcase emissions range from 10% to 25% of the total engine emissions, depending on the engine and the operating duty cycle. Crankcase emissions typically contribute to a higher percentage (up to 50%) of total engine emissions when the engine is idling. The combined CCV/DOC system controls PM emissions by up to 33%, CO emissions by up to 23% and HC emissions by up to 66%.

Fuel Additives

Fuel additives are chemical added to the fuel in small amounts to improve one or more properties of the base fuel and/or to improve the performance of retrofit emission control technologies. Several cetane enhancers have been verified by EPA that reduce NOx 0 to 5%. Other additives are undergoing verification. There thousands of fuel additives on the market that have no emission or fuel efficiency benefit so it is important to verify the manufacturer's claims regarding benefits. EPA listed "verified retrofit technology."

Liquid Combustion Catalyst

Fuels borne catalyst systems (FBCs) are marketed as a stand-alone product or as part of a system combined with DPFs, FTFs, or DOCs. FBCs have included cerium, cerium/platinum copper, iron/strontium, manganese and sodium. A DPF must be used to collect the catalyst additive so it cannot be emitted to the air. A FBC/DOC system has been verified by EPA to reduce PM 25 – 50%, NOx 0 – 5%, and HC 40 – 50%. A FBC/FTF system has been verified by EPA to reduce PM 55 – 76%, CO 50 – 66%, and HC 75 – 89%. The estimated cost of the verified FBC is approximately $.05 per gallon. Pre-mixed fuel is recommended for retrofit applications. FBCs do not require ultra low sulfur diesel and work with a wide range of engine sizes and ages. EPA listed "verified retrofit technology."

Lean NOx Catalyst

Lean NOx catalyst (LNC) is a flow through catalyst technology similar to diesel oxidation catalyst that is formulated for NOx control. It typically uses diesel fuel injection ahead of the catalyst to serve as NOx reduction. Lean NOx catalyst can achieve a 10% to over 25% NOx reduction. It can be combined with diesel oxidation catalyst (DOC) or diesel particulate filter (DPF). Over 3500 vehicles and equipment have been retrofitted with Lean NOx catalyst and CB-DPF filter systems in United States. The sulfur lever level of the fuel has to be less than 15 ppm. Verified LNC systems use injected diesel fuel as the NOx reducing agent and as a result a fuel economy penalty of up to 3% has been reported**.** EPA listed "potential retrofit technology."

Low NOx ECM - Engine electronic control module (ECM) reprogram

Some engine manufacturers used ECM on 1993 through 1996 heavy-duty diesel engines that caused the engine to switch to a more fuel-efficient but higher NOx mode during off cycle engine highway cruising. As part of the manufacturers' requirements to rebuild or reprogram older engines (1993-1998) to cleaner levels, companies developed a heavy-duty diesel engine software upgrade (known as an ECM "reprogram", "reflash" or "low NOx" software) that modifies the fuel control strategy in the engine's ECM to reduce the excess NOx emissions. Low NOx ECM is available as a retrofit strategy to reduce NOx emissions from certain diesel engines. Emissions control performance is engine specific. A system verified for a Cummins engine by CARB provided 85% particulate and 25% oxidation reductions. Over 60,000 heavy-duty diesel engines have received ECM reprograms. CARB plans to require ECM reprogramming on approximately 300,000 to 400,000 engines. ECM application is limited to heavy-duty diesel engines with electronic controls. Most off-road engines are not equipped with electronic controls. ECM is available throughout the U.S. through engine dealers and distributors. The software can be installed on-site and the reprogram takes approximately 15 to 30 minutes.

Exhaust Gas Recirculation (EGR)

The EGR system used in retrofit applications employs low-pressure. Original Equipment EGR systems typically employ high-pressure. EGR as a retrofit strategy is a relatively new development but has been proven durable and effective over the last few years. In the U.S. retrofit low-pressure EGR systems is combined with a CB-DPF to allow the proper functioning of the EGR component. EGR can reduce the NOx formed by the CB-DPF. EGR/DPF systems have been verified by CARB. Over 3000 and exhaust gas recirculation diesel particular filter systems have been retrofitted onto on road vehicles worldwide. EGR/DPF systems can be applied to off-road engines. However, experience is limited and the off-road market not the primary target application in the U.S. Current experience with EGR/DPF systems has been a range of 190 horsepower to 445 horsepower. The fuel economy penalty from EGR component ranges from 1% to 5% based on technology designed to particular engine and the test/duty cycle. EPA listed "potential retrofit technology."

II. Description of how to implement

These controls would be voluntary retrofits for existing engines. Some of these controls may be used by engine manufacturers to meet EPA's diesel standards for new engines.

III. Feasibility of the option

A. Technical
B. Environmental
C. Economic

See the individual control summary descriptions above. For more detailed information consult Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, to be found at:
http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf

IV. Background data and assumptions used

As EPA verified retrofits or potential retrofits (with the exception of the bi-fuel option), the data and assumptions associated with this option have been evaluated and considered. See EPA's Voluntary Diesel Retrofit Program web pages (http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm and http://www.epa.gov/otaq/retrofit/retropotentialtech.htm) and Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, located at:
http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf for more information on these verified and potential retrofit controls.

V. Any uncertainty associated with the option

Low to high uncertainty depending on the application, engine, operating conditions. These are EPA verified or potential retrofits for diesel engines (with the exception of the bi-fuel option), but some controls are limited to specific applications.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

All existing or newly introduced diesel engines (on-road, non-road, and stationary) used in the 4 Corners area could utilize these control options with the limitations noted above.

ENGINES: TURBINES

Mitigation Option: Upgrade Existing Turbines to Improved Combustion Controls (Emulating Dry LoNOx Technology)

I. Description of the mitigation option

This option involves upgrading older units with improved electronic combustion control technology that approaches or meets Dry LoNOx for existing turbines and requires Dry LoNOx technology on all new turbines. The benefits of this mitigation option are lower NOx emissions, but it is an expensive option that may take several years to implement and may be difficult to achieve with some engine models. The tradeoffs is that a few people may spend a lot of money and not significantly impact overall nitrogen oxide emissions to meet the region's emission control objectives.

II. Description of how to implement

A. Mandatory or voluntary: Implementation should be assumed as voluntary until the existing turbine population is better understood.

Differing Opinion: The best technology should be mandatory.

B. Indicate the most appropriate agency(ies) to implement Federal, state, and tribal agencies responsible for air emissions compliance.

III. Feasibility of the option

A. Technical Individual turbine assessment will be needed to confirm appropriate size or design limitations (not all turbines can be retrofitted).
B. Environmental The benefits of a dry LoNOx emissions control technology on air emissions has been proven repeatedly for many large turbines.
C. Economic The economic impact cannot be understood without an inventory of installed turbines.

IV. Background data and assumptions used

No assumptions have been made at this time on the impact of emissions reductions due to the uncertainty of the existing turbine population.

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option High.

VII. Cross-over issues to the other source groups

The impact of implementing this option may be further evaluated by the Cumulative Effects or Monitoring groups.

EXPLORATION & PRODUCTION: TANKS

Mitigation Option: Best Management Practices (BMPs) for Operating Tank Batteries

I. Description of the mitigation option

This option involves implementing and/or adoption of various Best Management Practices (BMPs) for operating tanks that contain crude oil and condensate. The specific BMPs include the use of Enardo valves, closing thief and other tank hatches, maintaining valves in leak-free condition, closing valves, etc. so as to minimize VOC losses to the atmosphere.

Economic burdens are minimal since these practices are largely followed and considered a normal cost of doing business as part of responsible operations.

There should not be any environmental justice issues associated with following these practices in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement BMPs for operating tank batteries are envisioned as "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAS program and EPA's Natural Gas STAR Program. There are currently no mechanisms or rules to require BMPs as standards, and this seems implausible as a mandatory approach. Many companies have BMPs in place already.

B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The use of BMPs for operating tank batteries is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: Quantification of emission reductions from implementation of this mitigation option is not possible.
C. Economic: These BMPs need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. Oil and gas producing companies will need to educate their workforce on the validity and importance of these BMPs.
3. Employees will not react adversely to following these practices as a normal course of being a lease operator.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that this is viable and probable.

Mitigation Option: Installing Vapor Recovery Units (VRU)

I. Description of the mitigation option

This option involves using Vapor Recover Units (VRUs) on crude oil and condensate tanks so as to capture the flash emissions that result when crude oil or condensate is dumped into the tank from the production separator. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas were present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement VRUs for operating tank batteries are envisioned as "voluntary" measures since the feasibility of VRUs in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, VRUs are commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the costs economics will not generally justify installation of VRUs for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The use of VRUs for operating tank batteries is technically feasible.
Differing opinion: However, installation of a VRU to most existing tank installations is not likely feasible without a complete redesign and new installation. Most tanks are pressure rated at 3-5 psig and would need to be replaced with tanks designed with higher pressure rating to handle pressure surges during separator dumps. Additional pressure relief valving, pressure regulators and other safety devices would need to be included with these systems. Redesign and system replacement would need to be evaluated to determine the economic feasibility of this type of system. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present. Due to the small amount of condensate produced in 4-Corners wells, the periodic "dumping" from the separators to the tanks, and the consequent uneven flash of gas from the condensate the use of VRU's is technically very challenging and may not be technically feasible. VRU's start from atmospheric pressure and boost gas to low pressure that may not be sufficient to flow into the collection system lines. In this case, they are either not feasible or would require additional compression. The lack of electricity in the fields effectively precludes any operationally feasible VRU use.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented. Benefits are relative to production throughputs. VOC emissions from flashing emissions are a function of well pressure and condensate production. The amount of emission reduction will be proportional to the amount of uncontrolled VOC emissions. Even if VRU's can be made to work in the 4-corners area, the amount of VOC emission reduction per tank will be low due to the low condensate production rate.

C. Economic: The use of VRUs for recovering the flash emissions from produced crude oil/condensate are economically feasible where the Gas Oil Ratio (GOR) from produced crude oil/condensate is high and the daily production volume is at least 50 barrels/day or greater. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so VRUs are not economically feasible.

Flares or combustors could be considered an alternative control technology if sufficient VOC emissions exist. At 1 bbl/day and low pressure drop the flash gas volume and VOC content will not justify control systems.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of VRU economically infeasible.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM based on availability of power, high maintenance requirements and reliability/performance.

Differing opinion: This would rank a high level of uncertainty in actually achieving meaningful and cost effective emission reductions using this technology.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of VRUs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Gas Blankets Capability

I. Description of the mitigation option

This option involves modifying existing and installing new designed crude oil and condensate tanks that would be capable of placing an inert gas blanket over these tanks to minimize vapor loss. The inert gas would fill the space above the condensate/crude oil to minimize volatilization and vapor loss. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas if present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement gas blankets for operating tank batteries are envisioned as "voluntary" measures since the feasibility of gas blanket technology in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, gas blanket technology is one of several measures commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the cost economics will not generally justify installation of gas blankets for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The use of gas blankets for operating tank batteries is technically feasible but requires the tanks to be designed to handle the increased pressures that will result when crude oil/condensate enters the tank, thereby pressurizing the gas blanket. Currently crude oil/condensate tanks are designed as atmospheric tanks and are designed only to withstand 5 psig of internal pressure. API 12F specifies 16 oz of pressure for normal operation and no greater than 24 oz for emergency operations. Using gas blanket technology requires such tanks to withstand about 100 psig, which increases the costs for tanks substantially. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: If this is considered a candidate control technology, the detailed engineering and economic analyses are needed to evaluate the cost to control relative to other potential control measures.
C. Economic: The use of gas blanket technology for preventing the release of flash and vapor emissions from produced crude oil/condensate are economically feasible for large, centrally located tank batteries where the crude oil/condensate can be piped from numerous wells to a centralized facility. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so the use of pipelines to transport the crude oil/condensate to a centralized facility is uneconomic.

IV. Background data and assumptions used

1. Individual tank batteries rather than large, centralized tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the minimal daily production volumes (i.e., less than 1 barrel/day).

V. Any uncertainty associated with the option Low.

Differing opinion: HIGH based on feasibility comments above and additional regulatory requirements for pressurized vessels, transport of pressurized product, and added safety processes.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of gas blanket technology in the Four Corners areas is economically unfeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Floating Roof Tanks on Tanks in the Four Corners Region

I. Description of the mitigation option

This option involves using floating roof tanks on crude oil and condensate tanks so as to prevent the loss of emissions that result from crude oil or condensate stored in the tank. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient gas were present, there would be minimal economic benefits. However, the use of floating roof tanks on smaller tanks instead of fixed roof tanks do not reduce the emissions. The emissions actually increase.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement floating roof tanks on tank batteries are envisioned as “voluntary” measures since the feasibility of floating roof tanks in the Four Corners area is negative. At certain facilities in the country where tanks are considerably larger are commonly mandated by the respective Air Quality Control agency as BACT or LAER. The common sizes of tanks in the Four Corners area will not benefit economically or in emission reductions through installation of floating roof tanks. Generally, emissions will increase if floating roofs are installed on these small tanks. Therefore, this mitigation does not have merit for the Four Corners area and is recommended not to be implemented either voluntary or mandatory.
B. Indicate the most appropriate agency (ies) to implement**:** NMED, Colorado Air Pollution Control Division.

III. Feasibility of the option

A. Technical: The use of floating roof tanks on tank batteries is technically feasible, however, not currently available for smaller sized tanks.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented for larger tanks; however the documentation on smaller tanks with fixed roofs indicates an increase in emissions.
C. Economic: The use of floating tank roofs for preventing the working loss emissions from produced crude oil/condensate is not economically feasible.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of floating rank roofs economically infeasible.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option.

General agreement within working group members is that the use of floating tank roofs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

EXPLORATION & PRODUCTION: DEHYDRATORS/SEPARATORS/HEATERS

Mitigation Option: Replace Glycol Dehydrators with Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts to remove water from natural gas. Desiccants can be a cost-effective alternative to glycol dehydrators. Additionally, there are only minor air emissions from desiccant systems.

Desiccant dehydrators are very simple systems. Wet gas passes through a "drying" bed of desiccant tablets (e.g., salts such as calcium, potassium or lithium chlorides). The tablets pull moisture from the gas, and gradually dissolve to form a brine solution. Maintenance is minimal - the brine must be periodically drained to a storage tank, and the desiccant vessel must be refilled from time to time. Often, operators will utilize two vessels so that one can be used to dry the gas when the other is being refilled with salt.

Desiccant dehydrators have the benefit of greatly reducing air emissions. Conventional glycol dehydrators continuously release methane, volatile organic compounds (VOC) and hazardous air pollutants (HAP) from reboiler vents; methane from pneumatic controllers; CO_2 from reboiler fuel; and CO_2 from wet gas heaters. The only air emissions from desiccant systems occur when the desiccant-holding vessel is depressurized and re-filled – typically, one vessel volume per week.[1] Some operators have experienced a 99% decrease in CH_4/VOC/HAP emissions when switching over to a desiccant system.[2]

Other potential benefits of desiccant dehydrators include: reduced ground contamination; reduced fire hazard; low maintenance requirements (because there are no moveable parts to be replaced and maintained); and the elimination of an external power supply.[3]

Solid desiccants are commonly used at centralized natural gas plants, but glycol dehydrators are still the most popular form of dehydration used in the field.[4] Most probably this is because there are particular conditions under which desiccant dehydrators work best:

- **The volume of gas to be dried is 5 MMcf/day or less.** Many wells in the San Juan Basin average less than 5 MMcf/day,[5] so this should not be a constraint to using desiccant systems.
- **Wellhead gas temperature is low (< 59º F for CaCl and < 70º for LiCl)**. If the inlet temperature of the gas is too high, desiccants can form hydrates that precipitate from the solution and cause caking and brine drainage problems. It is possible to cool or compress gas to the appropriate temperatures, but this increases the cost of the desiccant system.
- **Wellhead gas pressure is high (> 250 psig for CaCl and >100 psig for LiCl).**

II. Description of how to implement

A. Mandatory or voluntary

Where feasible, it should be mandatory, since it is both cost effective and virtually eliminates air emissions from field dehydrators.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation.

B. Indicate the most appropriate agency(ies) to implement

Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

Differing opinion: The Federal area source MACT rules address glycol dehydrators and require controls for those whose size and throughputs justify control. This regulation was carefully considered and evaluated by EPA prior to finalization and should not be exceeded without careful analysis and justification.

III. Feasibility of the option

A. Technical

Desiccant dehydration is currently feasible under certain operating conditions (i.e., temperature and pressure of inlet gas). It may be possible to expand the applicability with add-on technologies (e.g., auto-refrigeration units to chill the inlet gas).[6]

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations. This technology needs to be thoroughly considered before adoption – although it looks good initially, long-term use has not proven to be sustainable.

B. Environmental

Under some environmental conditions (e.g., high temperatures) this option becomes less feasible. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

For new dehydration systems, desiccant systems have been shown to be a lower cost alternative (both for capital and operating costs) than glycol dehydrators.[7] The payback period to replace an existing glycol dehydrator with a desiccant system has been shown to be less than 3 years.[8] The economics stated are only valid for a small range of temperature, pressure, and water content combinations. Desiccant dehydration for hot, low pressure, or high water content gas streams is not cost effective when compared to glycol dehydration.

Differing opinion: Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

IV. Background data and assumptions used See endnotes.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Notes:

1. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 5. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf

2. U.S. Environmental Protection Agency. Natural Gas STAR Program. “Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators.” p. 1. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
3. Acor, L. Design Enhancements to Eliminate Sump Recrystalization in Zero-Emissions Non-Regenerative Desiccant Dryer. In: The Tenth International Petroleum Environmental Conference, Houston, TX. November 11-14, 2003 http://ipec.utulsa.edu/Conf2003/Papers/acor_78.pdf
4. Smith, Glenda, American Petroleum Institute, written comments to Dan Chadwick, USEPA/OECA, September 22, 1999. In. EPA Office of Compliance. Oct. 2000. Sector Notebook Project - Profile of the Oil and Gas Extraction Industry. EPA/310-R-99-006. p. 31
5. Lippman Consulting. May 16, 2005. “Production levels increase in San Juan Basin,” Energy Quarterly. http://www.businessjournals.com/ artman/publish/article_898.shtml
6. U.S. EPA. Natural Gas Star. Replace Glycol Dehydrator with Separators and In-Line Heaters. PRO Fact Sheet No. 204.
   http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/replaceglycoldehydratorwithseparators.pdf
   Auto-refrigeration has been used in other oilfield applications, such as chilling gas to enhance water condensation and separation.
7. U.S. Environmental Protection Agency. Natural Gas STAR Program. “Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators.” p. 16. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   For a system processing 1 MMcf/day natural gas, operating at 450 psig and 47 F:
   Total implementation (capital plus installation): $22,750 (desiccant) vs. $35,000 (glycol)
   Total annual operating costs: $3,633 (desiccant) vs. $4,847 (glycol)
8. U.S. Environmental Protection Agency. Natural Gas STAR Program. “Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators.” p. 17. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   This payback period was reported for a glycol dehydrator system that was replaced with a two-vessel desiccant dehydration system.

Mitigation Option: Installation of Insulation on Separators

I. Description of the mitigation option

This option involves modifying existing and installing new separators that are insulated so as to reduce fuel usage. The air quality benefits would be to minimize combustion emissions to the atmosphere (NOx, CO, NMHC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement insulated separators and vessels are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require insulated vessels as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The application of insulation to separators, tanks, or other heated vessels is technically feasible. Currently some companies are insulating newly installed on production separators and larger produced water tanks on a case-by-case basis.
B. Environmental: The environmental benefits of reduced NOx, CO, and NMHC pollution are well documented.
Differing opinion: It is unclear how much insulation would cut fuel consumption and consequently reduce emissions. The emissions from well-site production units are very small (the units are very small) and not a significant component of the regional NOx budget. Insulation of these units would make a small reduction in a very small number.
C. Economic: The application of insulation to separators, tanks, or other heated vessels for reducing fuel usage and minimizing combustion emissions from separators, tanks, or other heated vessels are economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For older units or vessels where the remaining life of the equipment is limited, the economics may not justify the application of insulation. Costs basis and frequency of maintenance and ultimate replacement of both blown and wrapped insulation should be identified.

IV. Background data and assumptions used

Most fired units in the Four Corners area are utilized during the time period from November through March to achieve their objective.

V. Any uncertainty associated with the option (Low, Medium, High) Low.
Differing opinion: High in terms of emission reductions.

VI. Level of agreement within the work group for this mitigation option TBD.

Mitigation Option: Portable Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts (e.g., calcium, potassium or lithium chlorides) to remove the water from natural gas.

Glycol dehydrators may be more suitable than desiccant systems in some field gas dehydration situations (e.g., when inlet gas has a high temperature and low pressure). But glycol dehydrators require regulator maintenance for optimal performance. During maintenance periods production wells are either shut-in or vented to the atmosphere (rather than running wet gas into the pipeline). Venting is especially popular for low-pressure wells, because it can be difficult to resume gas flow once they are shut in.

Portable desiccant dehydrators can be brought on-site during glycol dehydrator maintenance (or break-down) periods. This allows the gas to be processed and sent to the pipeline, rather than requiring the well to be shut-in, or the gas to be vented. These portable dehydrators can also be used to capture and dehydrate gas during “green completion” operations.

The benefits of utilizing portable desiccant dehydrators are: the ability to continue producing a well during glycol dehydrator maintenance; the elimination of methane, VOCs and HAPs that would otherwise be vented while glycol dehydrators are being serviced.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary at this point in time. There are technologies that would result in much more significant air emissions reductions that should have higher regulatory priority.

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company’s experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations.

B. Indicate the most appropriate agency(ies) to implement

Environment/Health Departments, which have the responsibility for the regulation of air quality.

III. Feasibility of the option

A. Technical

A portable desiccant dehydrator requires a truck that has been modified to house the dehydrator; and ancillary equipment (e.g., piping) to re-route gas flow from the glycol to the desiccant dehydrator. See the discussion of technical feasibility in the desiccant dehydration option paper – the same comments and issues apply here.

B. Environmental

Desiccant dehydration systems work best under certain gas temperature and pressure conditions. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

Capital cost of a 10-inch portable desiccant dehydrator is estimated to be greater than $4,000. Operating costs (e.g., labor, transportation, set-up and decommissioning) are on the order of $5,000/yr.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation. Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

One operator reports that portable desiccant dehydrators are economical when used on gas wells that produced more than 15.6 Mcf/day.

Obviously, a company would get the most economic benefit from owning this equipment if the equipment was kept in continual operation – i.e., moved from one site immediately to another.

IV. Background data and assumptions used

All information in this mitigation option comes from: U.S. EPA. *Portable Desiccant Dehydrators*. PRO Fact Sheet No. 207. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/portabledehy.pdf

V. Any uncertainty associated with the option TBD.
Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Mitigation Option: Zero Emissions (a.k.a. Quantum Leap) Dehydrator

I. Description of the mitigation option

Conventional glycol dehydrators route natural gas through a contactor vessel containing glycol, which absorbs water (and VOCs, HAPs) from the gas. Typically, gas-driven pumps are then used to circulate glycol through a reboiler/stripper column, where it is regenerated, then sent back to the contactor vessel. Distillation and reboiling removes VOCs, HAPs and absorbed water from the glycol, and releases these compounds through the "still column" vent as vapor. Conventional glycol dehydrators vent directly to the atmosphere. Add-on technologies, such as thermal oxidizers, can reduce the amount of methane and VOCs that are vented, but result in increased NO_x, particulate matter and CO emissions.[1]

Natural gas dehydration is the third largest source of methane emissions and causes more than 80% of the natural gas industry's annual HAP and VOC emissions.[2] In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent.

- Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler, instead of releasing them to the atmosphere.
- A water exhauster is used to produce high glycol concentrations without the use of a gas stripper.
- Methane emissions are further reduced by using electric instead of gas-driven glycol circulation pumps.

Benefits of this technology include:

- Elimination of methane emissions.[3]
- Elimination of virtually all VOCs (reduction from multiple tons per year to pounds per year.[4]
- Has a HAP destruction efficiency of greater than 99%.[5]
- Reduces emissions of particulate matter, sulfur dioxide, NO_x or CO emissions (these compounds are emitted when thermal oxidation, a competing method of reducing glycol dehydrator VOC emissions, is used).
- Eliminates the Kimray pump, which is typically used to circulate glycol. Kimray pumps require extra gas (which is eventually vented to the atmosphere) for pump power.[6]
  - Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.
  - Results in collection of condensate, which can be sold.

II. Description of how to implement

A. Mandatory or voluntary

The zero emissions dehydrator system offers incredible reductions in emissions. States that are experiencing air quality problems could make this a mandatory technology, and achieve large reductions in VOC, HAP and methane emissions.

Differing opinion: Previous statement requires supporting documentation and quantification of 'trade-off' pollutants.
B. Indicate the most appropriate agency(ies) to implement
Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

III. Feasibility of the option

A. Technical
The operation of the glycol circulation pump requires electric utilities or an engine generator set. The use of electric pumps (rather than fossil fuel driven pumps) will minimize NO_x, CO, CO_2, SO_2 emissions at the wellhead, but will result in some emissions at electrical generation source (e.g., coal-fired power plant).

Zero emissions dehydrators can be newly installed, and existing dehydrators can be retrofitted by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.[7] This requires a fuel or power source, for which associated emissions need to be quantified.

B. Environmental
Environmental benefit for this mitigation option needs to be defined.

C. Economic[8]
Capital costs of a zero emissions dehydrator are similar to the costs of installing a conventional dehydrator equipped with a thermal oxidizer (>$10,000). Operating and Maintenance costs are greater than $1,000 per year, but lower than the maintenance costs for conventional glycol dehydrators.

If operators were to install zero emissions dehydrators, EPA estimates that the payback to occur in less than a year.
Differing opinion: This presumes the ability to recover the hydrocarbons for sales – which is not without significant challenges and technical difficulties.

IV. Background data and assumptions used

The calculations of methane, VOC and HAP emissions from the zero emissions dehydrator were based on a dehydrator that processed 28 MMcf/day.[9] Other assumptions are contained in the endnotes.

If we had emissions data for glycol dehydrators from the San Juan Basin, we could provide a more accurate (and basin-specific) comparison of methane, VOC and HAP emissions from conventional dehydrators versus emissions from zero emissions dehydrators.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Notes:

1. Permit renewal application by Centerpoint Energy Gas Transmission Co. to Louisiana Department of Environmental Quality. AI# 26802. March, 2005. Available at: http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=2335&SearchText=centerpoint&startDate=1/1/2005&endDate=7/6/2006&category=

The application includes estimated emissions scenarios for controlling glycol dehydrator still column vent emissions with or without thermal oxidation.

2. McKinnon, H.W. and Piccot, S.D. 2003. "Emissions control of criteria pollutants, hazardous pollutants, and greenhouse gases, Natural Gas Dehydration, Quantum Leap Dehydrator." Environmental Technology Verification Program, Joint Verification Statement. U.S. EPA and Southern Research Institute. Available at: http://www.epa.gov/etv/pdfs/vrvs/03_vs_quantum.pdf
3. *ibid.*
4. Rueter, C.O., Reif, D.L. and Myers, D.B. 1995. Glycol dehydrator BTEX and VOC emissions testing results at two units in Texas and Louisiana. U.S. EPA Air and Energy Engineering Research Laboratory. Project No. EPA/600/SR-95/046.

   A study of two glycol dehydrators, processing 3.6 and 4.9 million standard cubic feet of gas per day, were found to have VOC emissions of approximately 19 and 37 tons of VOC/year, respectively. Tests run on the Zero Emissions Dehydrator, processing 28 million standard cubic feet of gas per day, resulted in average emissions of 0.0003 lb/h (2.6 lbs/yr). This is a dramatically lower amount of VOC emissions than conventional glycol dehydrators.
5. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)
6. Fernandez, R., Petrusak, R., Robins, D. and Zavodil, D. June, 2005. "Cost-effective methane emissions reductions for small and midsize natural gas producers," Journal of Petroleum Technology. Available at: http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf
7. U.S. EPA. "Zero emissions dehydrators," PRO Fact Sheet No. 206. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/zeroemissionsdehy.pdf
8. All of the economic information comes from: U.S. EPA. (see Note 7)
9. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)

Mitigation Option: Venting versus Flaring of Natural Gas during Well Completions

I. Description of the mitigation option

Both venting and flaring of natural gas result in the release of greenhouse gases, hazardous air pollutants (HAPs) and others.

The venting of natural gas primarily releases methane, a greenhouse gas. Depending on the composition of the gas, venting will release other hydrocarbons such as ethane, propane, butane, pentane and hexane. In some locations, natural gas contains the EPA-designated HAPs benzene, toluene, ethyl benzene and xylenes (BTEX). Both hexane (also a HAP) and the BTEX compounds are present in San Juan Basin natural gas, typically accounting for 0.3 - 0.6 % of the natural gas composition.[1]
Differing opinion: This is only true for the conventional production. Coal bed methane does not contain appreciable amounts of VOCs or HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compounds, such as hydrogen sulfide (H_2S), which is a highly toxic gas. In the New Mexico portion of the San Juan Basin, there are at least 375 gas wells, from at least five different producing formations, that contain hydrogen sulfide.[2]

Flaring is used as a means of converting natural gas constituents into less hazardous and atmospherically reactive compounds. The main purpose for flaring is for process safety reasons. Flaring is required when completing a well for two reasons: (1) the initial gas and liquids produced by most wells does not meet the gas gatherer's (pipeline's) quality requirements, and (2) the flare is the primary safety device in the event of an overpressure or equipment failure. The objective for both industry and the public is to minimize flaring where possible for both environmental and economic reasons. The assumption is that combustion processes associated with flares efficiently converts hydrocarbons and sulfur compounds to relatively innocuous gases such as CO_2, SO_2, and H_2O.

While industrial flares associated with processes such as refineries have the potential to be highly efficient (e.g., 98-99%), the few studies that have been conducted on oil and gas "field flares" have found much lower efficiencies (62-84%).[3] Fields flares without combustion enhancements (e.g., knockout drums to collect liquids prior to entering the flare; flame retention devices; pilots) have a much lower efficiency compared to properly designed and operated industrial flares.[4] Other factors, such as improper liquids removal,[5] low heating value of the fuel,[6] flow rate of gas,[7] and high wind speeds,[8] also decrease the combustion efficiency of flares.
Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

There is a dearth of information on combustion efficiencies for flares used during well completion events, but given the fact that these flares are more rudimentary than industrial or even solution gas flares, it is highly possible that they have even lower combustion efficiencies.
Differing opinion: There are a number of very well done flare studies published.

When flares burn inefficiently, a host of hydrocarbon by-products that include highly reactive VOCs and polycyclic aromatic hydrocarbons, may be formed.[9] Leahey et al. (2001) found more than 60 hydrocarbon by-products, including known carcinogens such as benzene, anthracene and benzo(a)pyrene, downwind of a natural gas flare estimated to be operating at 65% combustion efficiency.[10] The inefficient burning of hydrocarbons also produces soot (particulate matter).[11] Additionally, nitrogen oxides are formed during the combustion process, even if the flare gas does not contain nitrogen.[12]

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

See the Endnotes for a table that summarizes the potential health and environmental effects related to compounds released during flaring and venting.[13]

Differing opinion: Not having access to the original table(s), it appears that errors may have occurred when it was adapted given the unwarranted combination of gas constituents and combustion products in one table and some obvious flaws (i.e., VOCs, SO2 and NOx contributing to particulate pollution but not aggravating respiratory conditions).

Flares operated during well completion activities handle enormous volumes of gas, which is either vented or flared over a short period of time. The amounts of HAPs and VOCs produced during a typical well completion in Wyoming have been calculated. It has been estimated that a single well completion event, which lasts an average of 10 days, releases:

- 115 tons of VOCs, and 4 tons of HAPs (assumption: 100% venting); or
- *86* tons VOCs, and *3* ton HAPs (assumption: half of the gas is flared per completion, and the flare operates at 50% efficiency).[14]

Differing opinion: Many completions in Wyoming – particularly those with gas flow rates in the 4 MMSCF/day range suggested above – are completed using flareless completion techniques which significantly reduces volume flared (75 to 90% reduction). However, use of these techniques is limited to those areas where the reservoir pressure is high enough to clean up the well and get the gas into the pipeline.

While it is clear that flaring reduces the volume (mass) of VOCs and HAPs, questions remain, such as: what are the particular VOC and HAP compounds released during both venting and flaring; what are the concentrations of these compounds in ambient air; [15] and can well completion flares somehow be designed (e.g., better liquid removal, lower gas flow rates going to the flare) to more effectively destroy hazardous compounds.

For a true assessment of the relative benefits of flaring vs. venting (especially with respect to human health), there is a need for a better assessment of venting/flaring emissions from well completions in the San Juan Basin. This assessment should determine both volumes of emissions, and provide a characterization of VOCs, HAPs and other compounds emitted (volumes and species) during well completion venting and flaring.

<u>II. Description of how to implement</u>

Using methods similar to those used in Wyoming, calculations could be performed to estimate the amount of VOCs and HAPs released from flaring and venting during well completion events in the San Juan Basin. Information requirements include:

- volume of gas released (vented or flared) per well completion
- VOC and HAP weight % of the natural gas
- estimates of combustion efficiency of flares
- estimates of how often flares are extinguished (resulting in venting of gas)

Monitoring downwind of sites that are flaring and/or venting is needed, to better characterize concentrations and species of VOCs and HAPs, as well as other flaring by-products.

A. Mandatory or voluntary

Initially, it could be a voluntary initiative, but if that does not produce data or results there may need to be mandatory reporting and monitoring requirements.

B. Indicate the most appropriate agency(ies) to implement

State oil and gas commissions could require the reporting of well completion emissions volumes; and environment/health departments would be the appropriate agencies to require monitoring of venting and flaring emissions.

III. Feasibility of the option

A. Technical

Emissions volumes from well completions have been determined for Wyoming, so presumably it is technically feasible to determine volumes for the San Juan Basin. If the data do not exist, perhaps the monitoring work group could work with industry to calculate or develop estimates of these volumes specific to the San Juan Basin.

Researches in Alberta have been able to determine combustion by-products using on-site analytical equipment or through absorbent samplers for confirmatory analyses by combined gas chromatography/mass spectrometry. Flare combustion efficiency were then calculated using a carbon mass balance of combustion products identified in the emissions. See Strosher (1996), Endnote 4.

B. Environmental

None.

C. Economic

Emissions volumes from well completions: low cost.

The identification of compounds emitted during venting and combustion: unknown.

IV. Background data and assumptions used See Endnotes Section.

V. Any uncertainty associated with the option

High uncertainty: depends on willingness of industry and regulators to undertake the necessary data collection.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Notes:

1. Proportions calculated based on data from: Mansell, G.E. and Dinh, T. (ENVIRON International). September 2003. Emission Inventory Report - Air Quality Modeling Analysis For The Denver Early Action Ozone Compact: Development of the 2002 Base Case Modeling Inventory. p. 3-5. http://apcd.state.co.us/documents/eac/2002%20Modeling%20EI.pdf

Table 3-5. Average gas profiles (% composition) by formation for the San Juan Basin

	Mesa Verde	Dakota	Pictures Cliffs	Gallup	
Nitrogen	0.212	1.603	0	0.965	
Carbon Dioxide	1.388	1.034	1.403	0.639	
Methane	84.372	74.979	87.736	76.944	
Ethane	8.221	12.163	6.373	10.823	
Propane	3.19	6.488	2.651	6.552	
Butanes	1.432	2,532	1,148	2.551	
Pentanes	0.727	0.765	0.418	0.948	
Hexanes	0.459	0.437	0.270	0.578	
Benzene	0.0145	0.016	0.003		
Toluene	0.00706	0.003	0.0014		
Ethyl Benzene	0.00037	0.0001	0.0002		
Xylene	0.002	0.0006	0.001		
Calculated VOC and HAP content (not in original chart)					Average for all formations
HAPS (BTEX + hexane)	0.483	0.457	0.276	0.578	0.4483
VOCs (C1-C4)	97.94	96.93	98.33	97.82	97.753

2. Hewitt, J. (Bureau of Land Management). 2005. "H2S Occurrences San Juan Basin," a presentation at Hydrogen Sulfide: Issues and Answers Workshop. http://octane.nmt.edu/sw-pttc/proceedings/H2S_05/BLM_H2S_SanJuanBasin.pdf

3. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996.

Strosher (1996) found flaring efficiencies of 62-71% and 82-84% for sweet and sour gas flares, respectively. The sweet gas had a higher liquid hydrocarbon content than the sour gas being flared. Leahy et al. (2001, citation in Endnote 9) observed flare efficiencies of 68 ±7 % at sweet and sour gas flares in Alberta.

4. Seebold, J., Davis, B., Gogolek, P., Kostiuk, L., Pohl, J., Schwartz, B., Soelberg, N., Strosher, M., and Walsh, P. 2003. "Reaction Efficiency of Industrial Flares: the perspective of the past." International Flare Consortium, Combustion Canada '03 Paper. http://www.nrcan.gc.ca/es/etb/cetc/ifc/id4_e.html

5. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2. http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

When liquid content is too high, flares don't or won't ignite.

6. Kostiuk, L.W., M.R. Johnson & R.A. Prybysh. 2000 "Recent Research on the Emission from Continuous Flares," Paper presented at CPANS/PNWIS–A&WMA Conference (Banff, Alberta, April 10-12). Cited in: Seebold et al. (2003).

7. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 85.

Combustion efficiencies decreased from 70.6% (flow rate of 1 m3/min) to 67.2 % (flow rate of 5-6 m3/min) for sweet gas being flared at an oil tank battery in Alberta.

Increasing the flow increased the volatile hydrocarbons by about 33%, and the non-volatiles by three times the concentrations found in the lower volume flow.

8. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p. 1615

"It has been shown, as well, that flaring can be efficient only at low wind speeds because the size of the flare flame, which is an indicator of flame efficiency, decreases with increasing wind speed. Therefore, the flaring process could routinely result, during periods of moderate to high wind speeds, in appreciable quantities of products of incomplete combustion such as anthracene and benzo(a)pyrene, which can have adverse implications with respect to air quality."

9. Seebold, J., Gogolek, P., Pohl, J., and Schwartz, R. 2004. "Practical implications of prior research on today's outstanding flare emissions questions and a research program to answer them," Paper presented at the AFRC-JFRC 20004 Joint International Combustion Symposium, Environmental Control of Combustion Processes: Innovative Technology for the 21st Century. (Oct. 10-13, 2004; Maui, Hawaii). http://www.nrcan.gc.ca/es/etb/cetc/ifc/id12_e.html

For example, during the 1990s, research conducted as part of the Petroleum Environmental Research Forum's project 92-19 "The Origin and Fate of Toxic Combustion By-Products in Refinery Heaters" showed that even when burning laboratory grade methane "pure as the drifted snow" traces of higher molecular weight compounds not originally present in the fuel are found in the flue gas (e.g., ethylene, propylene, butadiene, formaldehyde, benzene, benzo(a)pyrene and other hydrocarbons in the gas phase up through coronene).

Seebold, et al. also report that, "the external combustion of hydrocarbon gas mixtures by any means, including flaring, literally manufactures and subsequently emits to the atmosphere traces of all possible molecular combinations of the elemental constituents present either in the fuel or in the air including the ozone precursor highly reactive volatile organic compounds (HRVOCs) and the carcinogenic hazardous air pollutants (HAPs).

10. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p.1614. http://www.awma.org/journal/pdfs/2001/12/Leahey.pdf

Speciated data for combustion products observed downwind of the sweet gas flare using solvent extraction methods.

Product	Volume (mg/m3)	Product	Volume (mg/m3)
Nonane	0.41	9h-fluorene, 3-methyl-	3.05
Benzaldehyde (acn)(dot)	0.53	Phenanthrene	10.01
Benzene, 1-ethyl-2-methyl-	0.13	Benzo(c)cinnoline	2.06
1h-indene, 2,3-dihydro-	0.34	Anthracene	42.11
Decane	1.72	1h-indene, 1-(phenylmethylene)-	1.94
Benzene, 1-ethynyl-4-methyl-	9.83	9h-fluorene, 9-ethylidene-	0.89
Benzene, 1,3-diethenyl-	1.27	1h-phenalen-1-one	1.86
1h-indene, 1-methylene-	0.28	4h-cyclopenta[def]phenanthrene	3.50
Azulene	21.20	Naphthalene, 2-phenyl-	1.98
Benzene, (1-methyl-2-cyclopropen-1-yl)-	11.47	Naphthalene, 1-phenyl-	1.82
1h-indene, 1-methyl-	1.66	9,10-anthracenedione	0.94
Naphthalene (can)(dot)	99.39	5h-dibenzo[a,d]cycloheptene, 5-methylene-	0.75
Benzaldehyde, o-methyloxime	0.27	Naphthalene, 1,8-di-1-propynyl-	1.14
1-h-inden-1-one, 2,3-dihydro-	0.74	Fluoranthene 51.35 Benzene, 1,1'-(1,3-butadiyne-1,4-diyl)bis-	2.07

Naphthalene, 2-methyl-	9.25	Pyrene	32.37
Naphthalene, 1-methyl-	6.18	11h-benzo[a]fluorene	2.25
1h-indene, 1-ethylidene-	1.22	Pyrene, 4-methyl-	9.13
1,1'-biphenyl	58.70	Pyrene, 1-methyl-	8.38
Naphthalene, 2-ethyl-	1.87	Benzo[ghi]fluoranthene	10.16
Biphenylene	42.81	Cyclopenta[cd]pyrene	29.77
Naphthalene, 2-ethenyl-	7.32	Benz[a]anthracene	17.33
Acenaphthylene	7.15	Chrysene	2.12
Acenaphthene	2.93	Benzene, 1,2-diphenoxy-	1.94
Dibenzofuran	0.88	Methanone, (6-methyl-1,3-benzodioxol-5-yl)phenyl-	0.95
1,1'-biphenyl, 3-methyl-	0.31	Benzo[e]pyrene	0.71
1h-phenalene	21.01	Benzo[a]pyrene	1.03
9h-fluorene	41.09	Perylene	0.62
9h-fluorene, 9-methyl-	1.07	Indeno[1,2,3-cd]pyrene	0.15
Benzaldehyde, 4,6-dihydroxy-2,3-dimethyl	1.16	Benzo[ghi]perylene	0.26
9h-fluorene, 9-methylene-	1.07	Dibenzo[def,mno]chrysene	0.15
		Coronene	0.08

11. U.S. Environmental Protection Agency. 2000. Office of Air Quality Planning and Standards. “Industrial Flares,” AP-42 Fifth Edition. Vol. 1: Stationary Point and Area Sources. p. 13.5-3.
Tendency to smoke or make soot is influenced by fuel characteristics and by amount and distribution of oxygen in the combustion zone. All hydrocarbons above methane tend to soot. Soot from industrial flares is eliminated by adding steam or air.
Soot emissions factors developed by EPA for industrial flares are: non-smoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
12. K.D. Siegel. 1980l. Degree of Conversion of Flare Gas in Refinery High Flares. Dissertation. University of Karlsruhe, Germany. Cited in: USEPA Office of Air Quality Planning and Standards. 2000. “Industrial Flares,”AP-42 Fifth Edition. Volume 1: Stationary Point and Area Sources. p.13.5-5.
Even waste gas that does not contain nitrogen compounds form NO. It is formed either by fixation of atmospheric nitrogen with oxygen, or by the reaction between hydrocarbon radicals and atmospheric N by way of intermediate states, HCN, CN and OCN.
13. Health and Environmental Effects of Chemicals Released During Venting and Flaring.

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/ SOOT
Contributes to particulate pollution that can cause respiratory illness, aggravation of heart conditions and asthma, permanent lung damage and premature death.								
	FLARING	FLARING	FLARING					FLARING
Aggravates respiratory conditions						VENTING		
								FLARING

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/SOOT
Can cause health problems such as cancer	VENTING						VENTING	
	FLARING				FLARING		FLARING	
Can cause reproductive, neurological, developmental, respiratory, immune system, and other health problems.							VENTING	
							FLARING	
Reacts with other chemicals leading to ground-level ozone and smog, which can trigger respiratory problems	VENTING							
	FLARING		FLARING					
Reacts with common organic chemicals forming toxins that may cause bio-mutations								
			FLARING					
Affects cardiovascular system and can cause problems within the central nervous system						VENTING		
Causes haze that can migrate to sensitive areas such as National Parks	VENTING							
	FLARING	FLARING	FLARING	FLARING				FLARING
Contributes to global warming	VENTING							

Adapted from: EPA Office of Inspector General. 2004. EPA Needs to Improve Tracking of National Petroleum Refinery Program Progress and Impacts. Appendix D.

14. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2. http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

15. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 28.

Strosher measured concentrations of hydrocarbon compounds emitted from sweet and sour solution gas flares in Alberta, and then predicted ground-level concentrations of HAPs at various locations around the well location. Predicted values of some polycyclic aromatic hydrocarbons in the vicinity of sweet and sour gas flares were comparable to concentrations found in large industrial cities, while predicted values of hazardous VOCs released during flaring were below ambient air quality standards.

Mitigation Option: Co-location/Centralization for New Sources

I. Description of the mitigation option

This mitigation option would involve co-locating and/or centralizing new oil/gas field facilities, including roads, well pads, utilities, pipelines, compressors, power sources and fluid storage tanks, wherever possible, to reduce surface impacts, fugitive dust, engine emissions and gas field traffic.

In general, co-location and/or centralization of new facilities would result in overall reductions in surface disturbance, vehicular traffic, and number of facilities. Potential benefits from this strategy include fugitive dust reduction (due to decreased traffic and less overall new surface disturbance), vehicle emission reductions, reduced road maintenance, safer roads as a result of decreased traffic, and oil/gas field engine emission reductions. The potential for reduced engine emissions is due in part to lowering cumulative horsepower requirements by using larger, more efficient engines, and in part to groups of smaller engines with relatively high emission rates per hp/hr being replaced by fewer, larger engines with relatively low emission rates per hp/hr. Implementation costs for this mitigation option would fall exclusively on the energy companies, but such costs could be partially offset by the economic benefits of having fewer facilities to construct, maintain and ultimately reclaim.

Tradeoffs include increased impacts at co-located/centralized sites. Co-locating well bores on a single pad results in larger pad sizes that may not fit well with pre-existing conditions. Centralizing facilities would increase vehicle emissions locally and potentially produce local air quality, noise, visual and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis, with the approach emphasized by the appropriate regulatory agency during the planning and permitting processes for oil/gas field facilities and utility corridors (pipelines, power lines, etc.). Consideration should be given to economic and environmental impacts, as well as current and future land management activities. Ideally, oil/gas field operators and regulatory agencies would coordinate on a regular basis to identify development plans that minimize new construction and maximize efficiencies. Cooperation between operators in the same development area would make this option even more effective, but multiple economic and regulatory constraints exist that make such coordination difficult.

B. State and Federal lands and minerals management agencies would be able to emphasize this approach at various stages of the planning and permitting process. In addition, State and Federal air regulatory agencies could emphasize this approach if multiple air quality permit applications are submitted concurrently for the same general area.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option. This option is best suited for areas of known or high potential for economic oil/gas field production. This option can be implemented most effectively when planning for oil/gas field- or lease-wide development activities, such as in-fill drilling and plans of development for multiple wells.

B. Environmental: Co-location and/or centralization of new facilities would generally have numerous environmental benefits.

C. Economic: Economic feasibility of this option will vary on a project-level basis. Higher initial costs may be offset by overall cost reductions due to fewer facilities to construct, operate and reclaim. Additional cost savings may result because co-located/centralized facilities can be more efficient than dispersed facilities.

IV. Background data and assumptions used

This option is best suited for areas with existing or high potential for economic gas/oil field production.

V. Any uncertainty associated with the option

Low. While implementation of this option may cause greater noise, emission, and visual impacts at fewer, co-located/centralized locations, the overall effect would be a reduction in oil/gas field environmental impacts.

VI. Level of agreement within the work group for this mitigation option Unknown at this time

VII. Cross-over issues to the other source groups

Road-related impacts are an element of this mitigation option being looked at by the Other Sources Workgroup. Two other mitigation strategies (Optimization/Centralization and Reduced Truck Traffic by Centralizing Produced Water Storage Facilities) look at the compression and produced water facets of this mitigation option in greater detail and are presented in the Oil and Gas section of this Task Force Report. Assistance from the Cumulative Effects work group to quantify potential dust, vehicle traffic and overall emission reductions resulting from co-location and/or centralization would be helpful.

VIII. References

http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html

http://www.westgov.org/wga/initiatives/coalbed/

http://bogc.dnrc.state.mt.us/website/mtcbm/webmapper_cbm_info_res.htm

Mitigation Option: Control Glycol Pump Rates

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. The amount of methane absorbed, and used as assist gas for Kimray type pumps, and vented is directly of the TEG Dehydrator, but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Reducing TEG circulation rates reduce methane emissions at negligible cost.

Economic burdens are minimal since this practice simply requires the pump rate to be manually adjusted.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of lower TEG circulation rates should be "voluntary" since the measure would enhance recovery of natural gas and reduce emissions. Companies should be receptive to voluntarily implement this measure.
B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should communicate this information.

III. Feasibility of the option

A. Technical: Controlling TEG circulation rates are technically feasible since it can be achieved by manually setting the pump rate.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented. The reduction of methane, a greenhouse gas, can also be documented. Quantification of emission reductions can be achieved through the use of the GLYCALC model.
Due to the low field pressures in the San Juan basin area, most field dehydrators have been removed and dehydration is done at central facilities rather than dispersed locations. Due to this, this option will have very limited applicability and emission reductions associated with it.
C. Economic: The benefits can be quantified by the amount of methane and VOC that is not emitted to the atmosphere and rather sold as product.

IV. Background data and assumptions used

A. Gas production fields experience declining production as pressure is drawn-off the reservoir. Wellhead glycol dehydrators and their TEG circulation rates are designed for the initial, highest production rate, and therefore, become over-sized as the well matures. It is common that the TEG circulation rate is much higher than necessary to meet the sales gas specification for moisture content.
B. The methane emissions from a glycol dehydrator are directly proportional to the amount of TEG circulated through the system. The higher the circulation rate, the more methane, is vented from the regenerator. Over-circulation results in more methane emissions without significant and necessary reduction in gas moisture content.
C. Operators can reduce the TEG circulation rate and subsequently reduce the methane emissions rate, without affecting dehydration performance or adding any additional cost.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is doubtful a disagreement about controlling TEG circulation rates would occur.

Source of Information: "Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators", U.S. EPA Natural Gas Star Program.

Mitigation Option: Combustors for Still Vents

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The TEG is then distilled to strip water and consequently VOC from the TEG. Vapors and/or liquids in the still vent are typically greater than 90% volume water, with the balance being hydrocarbons along with small quantities of carbon dioxide and nitrogen. The still vent column is typically released to the atmosphere that includes emissions of hydrocarbons. It is important to note that gas composition is an important consideration in determining the need to install flares. Some natural gas, such as coalbed methane gas contains little, if any VOC component, and would not result in VOC emissions.

In order to reduce these emissions, combustion devices can be installed to combust hydrocarbon emissions, including VOCs, instead of venting them to the atmosphere. The combustion technology typically consists of an enclosed "flare/burner." It does require a condenser and separator upstream of the combustion device to avoid liquid hydrocarbons routed to the combustion device.

II. Description of how to implement

A. Mandatory or voluntary: The requirement for control of emissions from glycol dehydrators is included in the EPA's area source *Onshore Natural Gas Processing* MACT rules that have been proposed/promulgated. After careful analysis, EPA set emission and throughput based criteria to trigger these control requirements. Any control at lower emission or throughput rates should be voluntary.
B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should develop the regulatory program to administer this program.

III. Feasibility of the option

A. Technical: Installing condensers and combustion devices to control emissions from dehydrator still vents is technically feasible since it is already being applied in various locations where controls of these emissions have been mandated.
B. Environmental: The environmental benefits of reduced VOC emissions are well documented. The reduction of methane, a greenhouse gas, can also be documented. Actual benefits are dependent on the amount and composition of the gas being dehydrated and are highly variable. Little benefit is expected for the San Juan basin due to the lack of field dehydration.
C. Economic: Costs are for a typical condenser and smokeless combustion chamber large enough to service a dehydrator in Wyoming are about $35,000 installed. There are no revenues from the gas as it is destroyed through combustion, and there is a fuel cost of about $1,800 per year for each pilot (at $3 per Mcf of gas).

IV. Background data and assumptions used Wyoming oil and gas presumptive BACT guidance.

V. Any uncertainty associated with the option Low where applicable.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is unknown about the degree of acceptance regarding the use of combustors for still vents.

Source of Information: "Install Flares", PRO Fact Sheet No. 905, U.S. EPA Natural Gas Star Program. Gas Research Institute, Control Device Monitoring of Glycol Dehydrators; Condenser Efficiency Measurements and Modeling, 1997.

EXPLORATION & PRODUCTION: WELLS

Mitigation Option: Installation and/or Optimization of a Plunger Lift System

I. Description of the mitigation option

Overview
In mature gas wells, the accumulation of fluids in the well-bore can impede and sometimes halt gas production. Fluids are removed and gas flow maintained by removing accumulated fluids through the use of artificial lift (such as a beam pump) or enhanced fluid lift treatments or techniques, such as plunger lifts, velocity strings, swabbing, soap injection, or venting the well to atmospheric pressure (referred to as “blowing down” the well). Fluid removal operations, particularly well blow-downs, may result in substantial methane and associated VOC emissions to the atmosphere.

Installing a plunger lift system can be a cost-effective alternative for removing liquids on wells where the well-bore configuration, pressure profiles, and production characteristics enable its application. Plunger lift systems have the additional benefit of potentially increasing production, as well as significantly reducing methane and associated VOC emissions associated with blow-down operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Air Quality and Environmental Benefits

The installation of a plunger lift system serves as an interim well-bore deliquification methodology for the period between natural flowing lift and full artificial lift and can yield environmental and production benefits while reducing well blow-downs and their associated emissions. The extent and nature of these benefits depend on the individual well characteristics and the method of plunger lift control and operation.

New automation systems and control capabilities can improve plunger lift system optimization, monitoring, and control. For example, technologies such as programmable logic controllers and remote transmitter units can allow operators to control plunger lift systems thorough control algorithms or remotely, without regular field visits. These systems can offer enhanced plunger lift operation and effectiveness versus older plunger control systems.

By reducing the need for well-bore blow-down, plunger lift systems can lower emissions. Reducing repetitive remedial treatments and well work-over may also reduce methane and associated emissions. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blow-down and an average of 30 Mcf per year by eliminating or reducing well work-overs.

Economics
Lower capital and operational cost versus installing full artificial lift equipment (such as a beam pump). The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain artificial lift equipment.

Lower well maintenance and fewer remedial treatments. Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blow-downs are reduced or no longer needed with plunger lift systems.

More effective well-bore deliquification and continuous production may improve gas production rates and increase efficiency. With proper optimization and control, plunger lift systems can also conserve the well’s lifting energy and increase gas production. Regular fluid removal allows the well to produce gas continuously and helps prevent fluid loading that periodically halts gas production or "kills" the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

Reduced paraffin and scale buildup. In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with "wobble-washers" to improve their "scraping" performance.

Other economic benefits. In calculating the economic benefits of plunger lifts, the savings from avoided emissions and enhanced production are only two factors to consider in the analysis. Additional savings may result from lower operational and well work costs.

Tradeoffs

Plunger lift systems do fail and can require additional maintenance versus blowing wells down. If return velocity is not controlled they may also "launch" through the plunger receiver and cause wellhead failure. Also, dependent on the control systems, they may require regular operator intervention.

Burdens

Installation of plunger lift systems can involve substantial costs particularly if changes to the well-bore tubulars are required. If adequate control systems and a means to power them are not available on a particular well, their installation will require additional expenditures.

<u>II. Description of how to implement</u>

<u>A. Mandatory or voluntary:</u> This option should be voluntary given the restrictions on applicability posed by well-bore configuration, pressure and build-up profile, and production characteristics. Each well must be evaluated for feasibility of plunger lift systems. A large number of wells in the Four Corners area already have artificial lift systems or other enhanced deliquification techniques already installed. Requiring all wells in the basin to replace other means of enhanced or artificial lift would be logistically and operationally unreasonable. A large percentage of the producing wells in the 4-corners area are already equipped with plunger lift systems. Most operators have an ongoing well evaluation program to determine the appropriate deliquification technology to apply to any particular well.

<u>B. Indicate the most appropriate agency(ies) to implement</u>**:** Non-applicable – voluntary implementation. However, workshops on plunger lift applicability, control, and operation may enhance implementation.

<u>III. Feasibility of the option</u>

A. Technical: The technical considerations necessary for plunger lift systems are well known and plunger lift systems are feasible where the well characteristics enable application. For very low pressure/flow environments, such as portions of the San Juan Basin, operation of plunger lifts may require periodic venting (blow-down) of well-bores to the atmosphere to generate enough differential energy to lift the plunger and associated fluids. Advanced control systems can significantly reduce the need for this type of blow-down but require robust automation capabilities.

<u>B. Environmental:</u> There are no known environmental issues with plunger lift implementation and they typically reduce emissions.

<u>C. Economic:</u> the economics of applying plunger lift technology to a particular well must be evaluated on a well-by-well basis. For wells where they are applicable, plunger lift systems are generally economic.

<u>IV. Background data and assumptions used</u> N/A

V. Any uncertainty associated with the option

Assuming a well-by-well evaluation of applicability the uncertainty associated with plunger lift implementation should be low. Due to the large number of wells already equipped with plunger lift or other enhanced or artificial lift systems the scope of available implementation may be limited.

VI. Level of agreement within the work group for this mitigation option

Still being evaluated, but based upon information to date it should be high.

Mitigation Option: Implementation of Reduced Emission Completions (Green Completions)

I. Description of the mitigation option

The "green completions" control method reduces methane losses during gas well completions. During well completions it is necessary to clean out the well bore and the surrounding formation perforations. This is done both after new well completions and after well workovers. Operators produce the well to an open pit or tanks to collect sand, cuttings and reservoir fluids for disposal. Normal practice during this process is to vent or flare the natural gas produced. Venting may lead to dangerous gas buildup, so flaring is preferred where there is no fire hazard or nuisance issue (concerns about smoke, light, noise, etc.). Green completions recover the natural gas and condensate produced during well completions or workovers. This is accomplished using portable equipment to process the gas and condensate so it is suitable for sale. The additional equipment may include more tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The recovered gas is directed through permanent dehydrators and meters to sales lines, reducing venting and flaring. "Green completion" techniques are only applicable where the reservoir pressure and flow is sufficient to clean-up a well bore after completion and still have sufficient pressure to enter the collection system/pipeline. With the depleted status of the conventional San Juan basin reservoirs and the characteristics of coal bed methane reservoirs; this is not an available option for the SJ basin area.

II. Description of how to implement

A. Mandatory or voluntary

This process can be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement

For the 4 Corners area, State regulatory agencies could require green completions through regulation or policy. For example, in the Pinedale, WY area the State of Wyoming, BLM, and operators have agreed to minimize flaring operations through use of green completions. FLMs could require this process through stipulations or conditions of approval in leases and applications for permits to drill.

III. Feasibility of the option

A. Technical

The green completion process can apply to the drilling of all natural gas wells, however, a sales line connection and sales agreements need to be arranged before the well drilling is completed. There are operational, access and other considerations that make this a case determination.
Differing opinion: This technique is not feasible in the SJ basin – see above.
The green completion process has been reviewed by EPA and is listed under "Recommended Technologies and Practices" on EPA's Natural Gas Star Program web site:
http://www.epa.gov/gasstar/techprac.htm **Differing opinion:** This technology may not be applicable in all cases, and needs careful consideration. Different formations typically require different completion techniques that this technology may not be suited to handle. E.g. many operators use compressed air to fracture coal wells. Air mixed with natural gas cannot be shipped to a pipeline due to the high potential for spontaneous combustion under typical pipeline temperatures and pressures. Additionally, oxygen contamination of natural gas causes additional corrosion risks to gathering lines. Separation of air from natural gas is presently not feasible or part of the process equipment used in "green completions."

B. Environmental

Nationally EPA has estimated that 25.2 billion cubic foot (Bcf) of natural gas can be recovered annually using Green Completions - 25,000 million cubic foot (MMcf) from high pressure wells, 181 MMcf from low pressure wells, and 27 MMcf from workovers. This reduces emissions of methane (a greenhouse gas), condensates (hazardous air pollutants), and nitrogen oxides (precursor to ozone formation and visibility degradation) formed when gas is flared. An EPA Gas Star Partner reported an estimated methane emissions reduction, as the total recovered from 63 wells, of 7.4 MMcf per year, which is 70 percent of the gas formerly vented to the atmosphere.

C. Economic

A methane savings of 7 MMcf per year based on completing 60 wells per year at the average recovery reported by an EPA Gas Star partner. The partner also reported recovering a total of 156 barrels of condensate from the 63 wells, an average of 2.5 barrels per well.

The capital costs include additional portable separators, sand traps, and tanks at a cost reported by the partner of $180,000. This equipment would be moved from well-to-well, so amortizing the cost over 10 years and doing 60 wells per year, the annual capital charges would be under $10,000. Incremental operating costs are assumed to be over $1,000 per year. At a natural gas price of $3 per Mcf and condensate price of $19 per barrel, green completions will pay back the costs in about 1 year. This information is for green completions in the Green River Basin area of Wyoming and is for much higher rate wells with much higher pressures and energy than the SJ basin wells.

IV. Background data and assumptions used

Information on Green Completions comes from EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm

V. Any uncertainty associated with the option

Low, if the well is part of an in-fill and a sales line connection is available. Other situations may not be suitable for green completions.

Differing opinion: Very High – this is not a viable option for the SJ basin area – see above.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Mitigation Option: Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls

I. Description of the mitigation option

This option would encourage oil and gas producers and pipeline owners and operators to replace or retrofit high-bleed natural gas pneumatic controls. This option should be considered when replacement of pneumatic controls with compressed instrument air systems is not practical or feasible (e.g. no electric power supply). It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleeds gas to the atmosphere and, consequently, are a leading source of methane emissions from the natural gas industry. High–bleed pneumatic devices are defined as those with bleed rates of 6 standard cubic feet per hour (scfh) or 50 thousand cubic feet (Mcf) per year. An EPA study in 2003 reported the constant bleed of natural gas from these controllers was collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies have found that the payback period can be less than a year for most retrofits from high-bleed to low-bleed pneumatic controllers. Recent experience indicates that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. If electric power is available, conversion from natural gas-powered pneumatic control systems to compressed instrument air systems will result in greater methane emissions reductions. However, the investment payback period will likely be longer, and may not be cost effective in some cases.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return From Reducing Gas Emission Losses. In many cases, the cost of converting high-bleed to low-bleed pneumatic controllers can be recovered in less than a year.
- Lower Methane Emissions

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. Due to the fact that almost all high-bleed pneumatics have been replaced by the industry, the economic returns from implementing low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Currently most operators have already replaced all high bleed with low bleed systems.
C. Indicate the most appropriate agency(ies) to implement: EPA and the State environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: These systems are off-the-shelf and proven.
B. Environmental: The environmental benefits of replacing high-bleed with low-bleed pneumatic controls, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by 50-260 Mcf per year per controller.
C. Economic: EPA reports that replacing or retrofitting high-bleed units with low-bleed units have a payback of five to 21 months.

IV. Background data and assumptions used

See the website for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option

Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

Cumulative effects should review oil and gas tasks and rank those most effective as priorities over those less effective or cost effective.

Mitigation Option: Utilizing Electric Chemical Pumps

I. Description of the mitigation option

This option involves replacing existing gas drive pumps with solar powered, electric-driven chemical pumps. The air quality benefits would be to minimize methane and VOC emissions to the atmosphere (Methane, VOC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to install electric-driven, solar powered chemical pumps are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require electric drive pumps as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.

B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The purchase and installation of electrically driven chemical pumps is technically feasible. Currently some companies are installing these pumps on a trial basis to assure performance during the winter months.

B. Environmental: The environmental benefits of reduced Methane and VOC pollution are well documented.

C. Economic: The use of electric-driven, solar powered chemical pumps is economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For existing older pumps exist on wells that have a future limited life, the economics may not justify the application of insulation.

IV. Background data and assumptions used

Most chemical pumps in the Four Corners area are utilized year round to achieve their objective.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

There is general agreement among working group members that the use of electrical chemical pump technology in the Four Corners areas is economically unfeasible and a likely source for voluntary adoption if the economics show a sufficient NPV.

Mitigation Option: Solar Power Driven Wellsites and Tank Batteries

I. Description of the mitigation option

This option comprises a system of production equipment and controls powered by solar generated electricity (through Photovoltaic – PV - cells) at gas well production sites that are not served with grid power. In most cases solar power replaces pressurized fuel gas, which is usually vented to the atmosphere after use. The power supply consists of solar panels and batteries. The solar power is used for electric instruments, controllers, actuators for automatic valves and small additive (methanol) pumps. Optimization consists of selecting the best fit items of hardware, becoming familiar with the strengths and limitations of all of the individual items as well as the overall system and making modifications to improve performance.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory on all new wellsites with gas-assisted chemical injection pumps. Mandatory where economic at existing wellsites. Propose to define a standardized calculation to determine if it is economic. An example borrowed from the Alberta EUB – Energy & Utilities Board – Directive 60, agreed to by a multi-stakeholder group including the oil & gas industry, includes the following:

1) Before tax basis
2) Point to an agreed upon specific gas forecast report
3) Must have remaining reserves calculation and production forecast (NPV calculated over life of well/production)
4) Only incremental capital costs related to the solar PV skid system may be included
5) Long term inflation based on CPI forecast
6) Discount rate = prime lending rate + 3%
7) Only revenue minus net royalties from incremental gas conservation only to be included
8) Economic if NPV before tax > $0

B. Indicate the most appropriate agency(ies) to implement**:** The States on State land or Federal/Tribe on Indian country.

III. Feasibility of the option

A. Technical: In the past two years an operator in Alberta has installed over 40 of these systems. Supported by operations managers, instrumentation personnel carried out trials with solar systems and electrical equipment to arrive at a “best fit” arrangement. In summer 2006, this operator carried out a study with outside specialist consultants in energy consumption and emissions monitoring to evaluate the performance of the system. The results of the study were very positive, resulting in this operator making their solar PV system the company standard for gas well production. The primary reasons for this are to reduce fuel consumption in producing operations, increase sales gas revenues and reduce vent gas emissions. There are also operators in the US Rocky Mountain area using solar PV systems in comparable ways.

B. Environmental: Reduced VOC emissions and reduced methane emissions (with a global warming potential ~23 times greater than CO2). Quantity of reduction would be dependent on number and bleed rate of pneumatic controllers, and size and supply gas use rate of pneumatic pump equipment, being replaced with electrically-powered devices.
C. Economic: Reduced fuel gas consumption so increased gas conservation and saleable product. These solar PV systems also minimize the requirement for expensive fuel gas regulators, shutdown devices and repair kits and stainless steel instrument tubing and fittings.

IV. Background data and assumptions used

See the presentation, "BP Canada Energy Company Innovative Methods for Reducing Greenhouse Gas - Low Emissions Wellsite" by Milos Krnjaja, BP Canada made at the "Energy Management Workshop for Upstream and Midstream Operations: Increasing Revenue through Process Optimization & Methane Emissions Reduction" in Calgary, Alberta Canada on 15-17 January 2007.
(http://www.methanetomarkets.org/events/2006/oil-gas/docs/15jan07-bp_canada_energy_company.pdf)

See the presentation, "Using Solar to Reduce Fugitive Gas Emissions" by Stuart Torr, Komex International made at the 2005 Energy Conservation and Air Emissions Technology Forum Wednesday, in Calgary, Alberta Canada on 19 October 2005.
(http://www.ptac.org/eet/dl/eetf0501p12.pdf)

See Database of State Incentives for Renewables and Efficiency (DSIRE) for a fast and convenient method to access comprehensive information on available state, local, utility, and federal **financial incentives** that promote renewable energy and energy efficiency.
(http://www.dsireusa.org/)

See Alberta Energy & Utilities Board – Directive 60 – Upstream Petroleum Industry Flaring, Incinerating, and Venting.
(http://www.eub.ca/docs/documents/directives/Directive060.pdf)

See Ber-Mac Electrical and Instrumentation for an example of a supplier of solar PV systems for instrumentation use. They have been in business since 1980 supplying electrical power and instrumentation equipment and services, both domestically and to international markets, supplying the needs of oil and gas companies all over the world. Their "Green Machine" is an environmentally-friendly, solar-powered operating system for new and existing wellsites.
(http://www.ber-mac.com/greenmachine.htm)

V. Any uncertainty associated with the option Low – a fair amount of industry experience and vendor capacity to-date.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that this is viable.

EXPLORATION & PRODUCTION: PNEUMATICS / CONTROLLERS / FUGITIVES

Mitigation Option: Optical Imaging to Detect Gas Leaks

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to use optical imaging to detect methane and other gaseous leaks from equipment, processing plants, and pipelines.

Optical imaging refers to a class of technologies that use principles of infrared light and optics to create an image of chemical emission plumes. They offer more cost-effective use of resources than traditional hand-held emissions analyzers, can screen hundreds of components or miles of pipeline relatively quickly and allow quicker identification and repair of leaks. The remote sensing and instantaneous detection capabilities of optical imaging technologies allow an operator to scan areas containing tens to hundreds of potential leaks, thus eliminating the need to visit and manually measure all potential leak sites.

Gas imaging can be either active or passive. Active gas imaging is accomplished by illuminating a viewing area with laser light tuned to a wavelength that is absorbed by the target gas to be detected. As the viewing area is illuminated, a camera sensitive to light at the laser wavelength images it. If a plume of the target gas is present in the imaged scene, it absorbs the laser illumination and the gas appears in a video picture as a dark cloud. Because it relies on the detection of backscattered radiation from surfaces in the scene, the process is referred to as Backscatter Absorption Gas Imaging (BAGI).

Passive gas imaging is based on a complex relationship between emission, absorption, reflection, and scatter of electromagnetic radiation. VOCs in the vapor phase have unique spectral emission and absorption properties. By measuring these properties, the gas species can be uniquely identified. By tuning the instrument’s spectral response to the unique spectral region of the VOC, the camera can make an image of a gas plume.

There is a variety of technologies available and in different stages of development for imaging hydrocarbon gases. Plume imaging technologies include BAGI and Hyperspectral Imaging systems. Remote detection sensing instruments include Open-path Fourier Transform Infrared (OP-FTIR), Differential Absorption Spectroscopy (DOAS), Light Detection and Ranging (LIDAR-DIAL), and Tunable Diode Laser Absorption Spectroscopy (TDLAS). These instruments can be hand held or shoulder mounted, van mounted, or operated from a helicopter or fixed wing aircraft, depending on the technology and the facility to be inspected.

As an example, the ANGEL service, which uses Differential Absorption Lidar (DIAL), can detect specific hydrocarbon gases with color video imaging from a fixed wing aircraft, quantify the plume concentration, encode GPS data on the image, and cover 1000 miles per day. This technology is most suited to a facility such as a pipeline or tank farm. For a gas processing plant, a hand held or shoulder mounted camera may be the technology of choice.

The benefits of using optical leak detection in an inspection and maintenance program include:

- Reductions in hydrocarbon gas emissions, both greenhouse gases and hazardous air pollutants;
- Improved safety; and
- Typical payback of less than one year in reduced methane product losses.

II. Description of how to implement

A. Mandatory or voluntary: This program would be a voluntary Best Management Practice. The economic returns from implementing optical leak detection should motivate producers to implement

them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: Several of these systems are commercially available.
B. Environmental: The environmental benefits of using optical imaging to detect and repair leaks have been documented. Companies reporting to EPA have reduced emissions significantly. Individual company results can be found on the EPA Natural Gas Star Program web site referenced below.
C. Economic: EPA reports that optical leak detection surveys pay for themselves in less than a year.
Differing opinion: Must be evaluated for each operation, may not be economic or applicable for all.

IV. Background data and assumptions used

See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

Individual companies' experience with optical imaging leak detection:

Dynergy: http://www.epa.gov/gasstar/pdf/ngstar_fall2005.pdf

Enbridge: http://www.epa.gov/gasstar/workshops/houston-oct2005/dodson.pdf

Also see the agendas from the 2003 – 2005 Gas STAR Program annual implementation workshops:
http://www.epa.gov/gasstar/workshops/imp_workshops.htm

Information on the ANGEL-DIAL technology:
http://www.epa.gov/gasstar/workshops/kenai/itt_sstearns.pdf

http://www.epa.gov/gasstar/pdf/ngspartnerup_spring06.pdf

Texas Commission on Environmental Quality report that includes comparison of various imaging technologies: http://www.tceq.state.tx.us/implementation/air/terp/Prop_02R04.html

V. Any uncertainty associated with the option Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

Mitigation Option: Convert Gas Pneumatic Controls to Instrument Air

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to convert pneumatic controls from natural gas to compressed instrument air systems. It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return from Reducing Gas Emission Losses. In many cases, the cost of converting to instrument air can be recovered in less than a year.
- Increased Life of Control Devices and Improved Operational Efficiency
- Avoided Use of Flammable Natural Gas. By eliminating the use of a flammable substance, operational safety is significantly increased.
- Lower Methane Emissions
-

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants where an electric power supply is available. For those sites that do not have electricity available, cost savings and methane emissions reductions can still be achieved by replacing high-bleed pneumatic devices with low bleed devices, retrofitting high-bleed devices, and improving maintenance practices. Experience has shown that these options often pay for themselves in less than a year.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. The economic returns from implementing instrument air or low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: These systems are off-the-shelf and proven. Best utilized at larger facilities.
B. Environmental: The environmental benefits of replacing high-bleed pneumatic controls with instrument air, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by an average of 20 Bcf per year per facility.
C. Economic: EPA reports that instrument air systems pay for themselves in less than a year. Replacing or retrofitting high-bleed units with low-bleed units have a payback of five months to one year.
Differing opinion: May not be economically justifiable or operationally sound for small facilities and well sites.

IV. Background data and assumptions used

See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for instrument air:
http://www.epa.gov/gasstar/pdf/lessons/ll_instrument_air.pdf

And for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option Low: this is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

EXPLORATION & PRODUCTION: MIDSTREAM OPERATIONS

Mitigation Option: Application of NSPS and MACT Requirements for Existing Sources at Midstream Facilities

I. Description of the mitigation option

Overview

- This mitigation option would involve filling in the gaps where the NSPS and MACT fail to adequately regulate sources at midstream facilities. Filing in the gaps could include lifting exemptions on existing sources and lowering applicability thresholds. Specific examples include:
    - Subjecting existing stationary combustion turbines at midstream facilities to 40 CFR Part 63, Subpart YYYY;
    - Requiring existing 2 stroke lean burn and 4 stroke lean burn reciprocating internal combustion engines to meet 40 CFR Part 63, Subpart ZZZZ MACT standards at midstream facilities;
    - Requiring boilers, reboilers, or heaters with a design capacity of less than 10 mmBtu/hr to meet NSPS at 40 CFR Part 60, Subpart Dc at midstream facilities;
    - Requiring all midstream facilities to meet the requirements to 40 CFR Part 60, Subpart KKK; and
    - Requiring all amine sweetening units at midstream facilities to meet 40 CFR Part 60, Subpart LLL requirements.

  This option would involve case-by-case assessments of midstream facilities to determine whether additional pieces of equipment should be regulated under NSPS and MACT standards and to assess the feasibility of such regulation. The overall goal is to use NSPS and MACT standards as guides for further air pollution reductions at midstream facilities.

Air Quality/Environmental

- This mitigation option would lead to further reductions in hazardous air pollutants and criteria air pollutants by subjecting more units to regulation. By requiring more facilities and/or units to comply with NSPS and MACT, there may be an incentive to upgrade to cleaner equipment, which would provide additional air quality benefits.

Economics

- There would likely be additional costs associated with bringing previously unregulated facilities and/or units into compliance.
- The option may provide an incentive to replace older, less efficient equipment, which could lead to increased efficiency.
- There would be potential paybacks associated with methane recovery by complying with NSPS at Subpart KKK.

Tradeoffs

- None.

Burdens

- The burden would be on industry to bring facilities and/or units into compliance with the NSPS and MACT standard. Air quality impacts would be reduced, reducing burden on health and welfare. Regulatory agencies may have to revise rules to implement this mitigation options.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. NSPS and MACT standards work best as mandatory requirements.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies, EPA.

III. Feasibility of the option

A. Technical: There will need to be case-by-case assessments, but this appears to be a technically feasible option.
B. Environmental: No environmental feasibility issues are known.
C. Economic: There may be economic concerns that should be addressed, but this option is not infeasible based on economics. The goal is clean air and that may take an investment.
D. Other: There will likely need to be rule changes to implement this option that may present feasibility issues.

IV. Background data and assumptions used

Background data and assumptions used came from review of EPA NSPS and MACT standards.

V. Any uncertainty associated with the option (Low, Medium, High):

Low uncertainty. The NSPS and MACT provide a solid basis for air pollution control options. However, further discussion and comments may reveal other means of using NSPS and MACT standards to keep air pollution in check.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups: None.

Mitigation Option: Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance

I. Description of the mitigation option

Overview

Meeting NSPS and MACT standards at Midstream facilities can often be achieved using a variety of methods, some of which may be better than others. For example, the EPA is proposing to allow the use of infrared cameras to meet Leak Detection and Repair (LDAR) requirements set forth in several NSPS and MACT standards. 70 Fed. Reg. pp. 17401-17409. The EPA has indicated that infrared cameras can provide better data than Reference Method 21.

This mitigation option provides specific direction on how to meet NSPS and MACT standards so that the best methods of compliance are met. Specifically, it requires operators to use approved infrared cameras to meet LDAR requirements set forth at 40 CFR Part 60, Subpart KKK and 40 CFR Part 63, Subpart HH and HHH.

It would also require operators to implement cost-effective options for reducing methane emissions, as outlined in Fernandez, et al. 2005, to meet applicable NSPS and MACT standards. These cost-effective options would vary depending on the equipment, but would include using vapor recovery units on tanks and dehydrators, using desiccant dehydrators rather than glycol dehydrators, replacing compressor rod packing after three years, replacing gas starters on compressor engines with air starters, and converting gas pneumatics at facilities to instrument air.

Air Quality/Environmental

- Meeting LDAR requirements using infrared cameras promises to better keep volatile organic compound and hazardous air pollutant emissions from leaking equipment in check. Implementing cost-effective options for reducing methane emissions will further reduce emissions. In both cases, methane emissions would be reduced, preventing further greenhouse gas emissions.

Economics

- This mitigation option will most likely yield a payback due to the recovery of methane. According to one case study, BP recovered $2.4 million in 2 months simply by recovering over 123 MMcf/yr of that was lost due to equipment leaks (see, http://www.epa.gov/gasstar/workshops/hobbs72706/dim.pdf).

Tradeoffs

- The use of some cost-effective methane control options may require the use of electricity, such as vapor recovery units, which may be generated through coal or natural gas burning. Potential increases in emissions from electricity generation could be prevented through the use of solar or other renewable energy sources.

Burdens

- The only burden would be the restriction of flexibility for the operators and the investment cost.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. Although infrared cameras and methane control options can provide paybacks and are proven cost-effective, they are not widely used. Despite potential paybacks, current incentives do not appear to be strong enough to encourage their use. Mandatory requirements would provide that incentive.

B. Indicate the most appropriate agency(ies) to implement: State air quality agencies and EPA.

III. Feasibility of the option

A. Technical: Feasible, these technologies are already in use and are being implemented elsewhere.
B. Environmental: Vapor recovery units may require additional space at midstream facilities and could pose additional environmental impacts. This seems to present a limited environmental feasibility issue.
C. Economic: Given the paybacks from methane recovery, there are no economic feasibility issues.
D. Other: The EPA has not yet finalized its proposal to allow infrared cameras to be used solely to meet LDAR requirements in the NSPS and MACT.

IV. Background data and assumptions used

Background data was obtained from information on the EPA's Natural Gas Star Program website, www.epa.gov/gasstar, from the EPA's proposal to allow infrared cameras to be used to meet LDAR requirements at 70 Fed. Reg. 17401-17409, and from the Fernandez et al. 2005 paper, "Cost Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers," available online at http://www.epa.gov/outreach/gasstar/pdf/CaseStudy.pdf.

V. Any uncertainty associated with the option

Low uncertainty, especially with regards to the use of infrared cameras as effective tools to comply with NSPS and MACT LDAR requirements. Operators would still have to show that cost-effect methane control options would meet the applicable requirements of the NSPS and MACT.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

Possibly the Cumulative Effects Group due to indirect emission increases from coal or natural gas burning plants that may accompany increased use of vapor recovery units or other methane control options requiring electricity.

OIL & GAS OVERARCHING

Mitigation Option: Lease and Permit Incentives for Improving Air Quality on Public Lands

I. Description of the mitigation option

This option would provide incentives in the form of exceptions or waivers from lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands in exchange for a program of environmental mitigation activities that would reduce air emissions along with other types of environmental and ecological impacts.

Differing Opinion: The proposed activities that would reduce air emissions and surface disturbance in this section should become standard practices **but without** the proposed exchange for the exceptions or waivers from seasonal wildlife restrictions which would negatively impact public lands wildlife.

This option could provide incentives in the form of expedited permit processing for operating permits in exchange for a program of environmental mitigation activities that would require documented reductions in emissions from major and minor sources. This option is not intended to reduce protection for wildlife. Monitoring and adjustments in response to monitoring results would be used to assure that the package of mitigation activities and associated development does not adversely affect wildlife.

Differing Opinion: Additionally these incentives would not include the exception of waivers from lease stipulations or permit conditions of approval (“COAs”) for oil and gas drilling on public lands.

Expedited operating permit issuance from the appropriate agency in exchange for additional emissions reductions offers incentives for both industry and the agencies

Industry Incentives include:

- The streamlining of operating permits.
- Direct and prompt cooperation with permit issuing agency.
- Obtaining an operating permit at an accelerated rate allows for an accelerated startup date, thus increased resource production (may be especially helpful for minor source operating permits).

Environmental Incentives include:

- The addition of emission control equipment such as a catalyst, Zero Emissions (a.k.a. Quantum Leap) Dehydrator, directional drilling, complying with emission limitations relating to hours of operation, lean burn engine, and/or implementing a program of environmental mitigation activities that would reduce air emissions.

This option would work well in the areas that smaller agencies, such as Tribes, oversee the operating permits. This option would be implemented by the applicable permitting agencies.

It would be modeled after the experience in the Pinedale Anticline and Jonah fields in Wyoming where producers face seasonal limitations on drilling due to concerns about wildlife impacts. As a result, drilling is prohibited for several months during the year, delaying development and increasing costs. Several producers have applied for and been granted permission to drill year round in exchange for efforts that mitigate environmental impacts. These efforts combine improved technologies and innovative practices that together greatly reduce adverse impacts. They include: directional drilling to reduce the number of drilling pads, and thus the amount of surface disturbance, by half or more; using natural gas-fired drilling rigs to reduce air emissions; transporting produced water by pipeline to eliminate truck trips;

using mat systems on drilling pads to reduce surface impact; partial remediation of drilling pads after the drilling phase; eliminating flares during well testing and completion to reduce air emissions and noise; centralized fracturing and production facilities; low impact road construction techniques; and produced water recycling. Producers and BLM will monitor wildlife impacts as part of the program. Year round drilling has the added benefits of reducing the duration of drilling operations by one third-to one-half, and increasing stability of the local community as workers move in with their families, rather than commuting seasonally.

Differing Opinion: This suggestion of modeling after the experience in Wyoming's Pinedale Anticline and Jonah fields fails to address the widespread and significant concerns that have been expressed regarding current and future impacts of oil and gas activity on wildlife in these fields and the wildlife population declines that have been documented through scientific studies. The Pinedale Anticline and Jonah field experience has not proven to be a model for wildlife, and recent proposals to increase drilling may even adversely impact a federally threatened species, the Bald Eagle, and further exacerbate problems for the sage grouse, a species which some believe should be listed as federally endangered because of recent population declines. Another report that helps put the Jonah field experience in perspective came in December 2006, stating that in places one well was being drilled per every five acres. Repeated concerns about the impact on wildlife in these areas of Wyoming have been expressed by numerous and diverse groups of people ranging from private citizens, outfitters, hunters, environmental organizations, scientists, to government agency personnel including personnel from Wyoming's Game and Fish Department. Drilling exceptions granted in crucial big game winter range around Pinedale early winter 2006/2007 were granted in the face of opposition by Wyoming's Game and Fish Department.

Differing Opinion Continued: Monitoring has also not been a model experience in this area. According to reports of a May 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife.

This option would involve tradeoffs between seasonal restrictions, which would be relaxed, and a comprehensive wildlife and environmental impact plan which would use the kind of technologies and practices listed above. This plan would reduce impacts on wildlife, as well as on air quality, land and water resources, and on the local communities. Ecological and environmental monitoring would assess these impacts and allow for adjustments in the plans as activities proceed. All of these elements would be contained in agreements between the land management agencies and industry, with public input.

Differing Opinion: Exceptions or waivers from wildlife lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands likely would increase negative impacts of oil and gas activities on wildlife in the Four Corners. At least in Northwest New Mexico and likely in the other Four Corners states, it is important to remember that the seasonal closures in the Bureau of Land Management Farmington Field Office management area exist only for parts of the year with their length dependent upon the animal species and the reason for the restriction such as elk calving or antelope fawning. The restrictions are in place to protect species during times of the year when they are especially vulnerable such as nesting for raptors; wintering for deer, elk, and Bald Eagles; and birthing and caring for young for antelope and elk. Provisions for waiving, excepting, or modifying the oil/gas lease stipulations already exist according to the Bureau of Land Management Farmington Field Office's 2003 Record of Decision for Farmington's Proposed RMP and Final Environmental Impact. These restrictions should remain in place to protect wildlife, especially with the current and anticipated intensity of drilling.

Differing Opinion Continued: An indication of the major potential for the impact of oil and gas activity on wildlife is found in the 2006 Annual Report of the Sublette Mule Deer Study conducted in the Pinedale Anticline Project Area. Study results that "suggest that mule deer abundance in the treatment area declined by 46 % in the first 4 years of gas development."

Differing Opinion Continued: In the summer, 2006, publication of the New Mexico Department of Game and Fish titled New Mexico Wildlife under the regional outlook for Northwest New Mexico, wildlife biologists are reported to be "concerned about the effects the severely dry spring had on fawn survival in the state's **already depressed deer herds**." [Bolding is this author's.]

Differing Opinion Continued: Removal of the wintering restrictions for mule deer could create problems in New Mexico and in both this state and Colorado where migratory populations are shared. Another word of caution is found in the Upper San Basin Biological Assessment in the Comprehensive Wildlife Conservation Strategy (New Mexico's wildlife action plan accepted by the US Fish and Wildlife Service in 2006), which places mule deer in its list of Species of Greatest Conservation Need in the Colorado Plateau Ecoregion. Under "Problems Affecting Habitats or Species" in Chapter 5 of this document is this statement: "Of particular concern are energy development…" along with invasive species and livestock grazing practices. The document states that "coal bed methane development in the San Juan Basin is currently a major land use…Depending on the scale, density, and arrangement of each well site in relation to other sites, habitat loss and fragmentation in the portions of this habitat type [Big Sagebrush Shrubland] subjected to energy development are extensive. At this high level of development, effects may not be successfully mitigated."

Differing Opinion Continued: Pronghorn antelope numbers were so low at the time the Farmington Field Office's Draft Pronghorn Antelope Habitat Management Plan was published in March 2004, that the populations were described as struggling to survive, a change from when this species was common in the 1950's and 1960's. The restriction of drilling and construction activity during antelope fawning period from May 1 through July 15 was proposed as one of the ways to bring the populations back to eventual self-sufficiency.

These actions reduce air emissions from drilling rigs, from trucks (both diesel emissions and road dust), and from flaring. There are also benefits from reduced surface impacts and improved water management, as well as improved community stability.

Differing Opinion Continued: The actions that are offered that will reduce air pollution appear to be important ways to address our air quality problem and should become required practice because of the serious air pollution problems in the San Juan Basin. They should not come at an expense to area wildlife, which is already negatively impacted by direct and functional habitat loss due to oil and gas activities, as delineated in the 2003 Bureau of Land Management Farmington Field Office Draft Resource Management Plan and Environmental Impact Statement.

This option would work well in areas of the Four Corners region where new oil and gas projects are being proposed and where those projects face access limitations from wildlife stipulations or COAs. In these cases, the land management agencies (principally the BLM and the Forest Service) would have the greatest opportunity to negotiate agreements for infrastructure and operational changes from project start, in exchange for relaxing the access restrictions, along with monitoring for wildlife impacts. Monitoring of the air quality impacts, including documentation of reductions over similar projects without mitigation, would be required.

In New Mexico, this option could be integrated with the New Mexico Oil and Gas Association's (NMOGA) Good Neighbor Initiative.

Differing Opinion: Year round drilling will not improve air quality. The current drilling seasons are in place to protect the wildlife in the area. The improved technologies and innovative practices described above should be standard industry requirements and not be used in trade for expanded drill seasons.

Differing Opinion: BLM should not entertain compromising one environmental value in exchange for protecting another when industry is legally mandated to protect both. Year round drilling will only add to the stress wildlife currently experience in an already highly fragmented habitat. Even more, in the San Juan Basin industry has demonstrated their reluctance to routinely employ directional drilling as a means to avoid further habitat fragmentation. Since directional drilling "all wells" would be the cornerstone of the proposed mitigation option it seems that this options would not be favorably received by industry.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary and would rely on the operators, the agencies, and any local communities obtaining benefits from the arrangements.
B. Indicate the most appropriate agency(ies) to implement: BLM and the Forest Service on Federal land. State and tribal land management agencies may implement this option on state and tribal lands.

III. Feasibility of the option

A. Technical: The technological approaches to reducing impacts are already being implemented in Wyoming and other locations.
Differing Opinion: Four Corners states should use the technological approaches without industry cost being a factor.
B. Environmental: The environmental benefits of the mitigation measures are currently being documented in Wyoming. Many of them seem apparent. The impact of year round drilling (or other permit-related incentives) on wildlife would have to be closely monitored.
C. Economic: Many environmental mitigation measures turn out to be economically attractive as well (e.g., natural gas drilling rigs can reduce fuel costs by two-thirds). Year-round drilling can shorten the project length by one-third to one-half, improving project economics. Producers would have to anticipate an economic benefit in order to enter into agreements.

IV. Background data and assumptions used

Web sites and presentations from operators and BLM on the experience with this kind of agreement in Wyoming. The NMOGA web site has information on their Good Neighbor Initiative.

See the following web sites:
BLM environmental assessment of year-round drilling in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/questar/01ea.pdf
(See especially section 2.5 on Applicant-Committed Mitigation.)

Questar presentation on development in Pinedale:
http://www.wy.blm.gov/fluidminerals04/presentations/NFMC/028RonHogan.pdf\

BLM assessment of year round drilling demonstration project in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/asu/01ea.pdf

Jonah Infill Project:
Encana release: http://www.encana.com/operations/upstream/us_jonah_blm.html
BLM air quality discussion:
http://www.wy.blm.gov/nepa/pfodocs/jonah/92FEISAirQualSuppleQ-As.pdf
BLM EIS and Record of Decision: http://www.wy.blm.gov/nepa/pfodocs/jonah/

NMOGA Good Neighbors Initiative:
http://www.nmoga.org/nmoga/NMOGA%20Good%20Neighbor%20Initiative.pdf
Wyoming Mule Deer Study Report (1 site)
http://www.west-inc.com/reports/big_game/PAPA_deer_report_2006.pdf
Wyoming wildlife, sage grouse
http://stream.publicbroadcasting.net/production/mp3/wpr/local-wpr-563699.mp3
http://gf.state.wy.us/downloads/pdf/sagegrouse/Holloran2005PhD.pdf
Wyoming wildlife, Bald Eagle http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/06chap3.pdf 3-97
http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/07chap4.pdf 4-123
Wyoming Bureau of Land Management, wildlife monitoring (1site)
http://www.washingtonpost.com/wp-dyn/content/article/2006/08/31/AR2006083101482.html
New Mexico: Comprehensive Wildlife Conservation Strategy (CWCS)
http://fws-nmcfwru.nmsu.edu/cwcs/New_Mexico_CWCS.htm
New Mexico—2003 Bureau of Land Management Resource Management Plan/Environmental Impact Statement, Record of Decision http://www.nm.blm.gov/ffo/ffo_p_rmp_feis/docs/Farmington_ROD.pdf Appendix B

V. Any uncertainty associated with the option

Medium: Depends on opportunities (proposed projects) for implementing incentives in exchange for mitigation activities, on producer willingness to participate, and on BLM/FS state and regional office and tribal policy.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups Impacts from trucks and roads may overlap with the Other Sources work group.

Mitigation Option: Economic Incentives-Based Emission Trading System (EBETS)

I. Description of the mitigation option

The central idea of this option is that inherent economic incentives promote innovative ways to achieve emission reductions, including gains from efficiencies in operation and maintenance and in applications of new innovative engine and control technologies.

This option encourages the use of pollution markets through implementation of an emission trading system (ETS) along with cooperative partnerships to reduce air emissions with the aid of emission reduction incentives. Basically in an emission trading program, the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates. The fact that the certificates have value as an item to be sold or traded gives the owner an incentive to reduce the company's emissions. Simply stated in an ETS, a producer who has low-emission engines could sell emissions credits to a producer who has high-emission engines. Typically, 0.8 units of credit could be sold for each unit of reduction below the standard or reference level. The end result is a ratcheting down of overall emissions. This option does not contemplate multi-pollutant trading, but rather a separate market for each individual pollutant.

Approximately 30 state and federal ETS programs existed or were being developed in the U.S. in the later part of the 1990s. Examples of ETS that have worked reasonably well in achieving emission reductions and providing economic incentives to industry include the Illinois EPA's Emission Reduction Market System (ERMS), Indiana Department of Environmental Management's credit registry trading system, U.S. EPA's Acid Rain Program, and commercial and non-commercial institutions like Chicago Climate Exchange (CCX). In addition, in 2002 the US EPA approved a plan submitted by the WRAP, which contained recommendations for implementing the regional haze rule. The plan included an SO_2 emissions allowance trading program for nine Western states and eligible Indian tribes. As an example, EPA's program took about three years to plan and begin implementing.

The proposed economic incentives based emission trading system (EBETS) mitigation option can be developed or modeled after ETSs which have been successful and tailored to issues specific to the Four Corner region. Emission credits can accrue through a variety of methods that are complementary to or independent of other mitigation options developed herein by the Task Force. For example, credits can be gained through use of partnerships that that provide incentives for voluntary emission reductions, such as in the EPA's Natural Gas STAR Program or New Mexico's VISTAS program (see the IBEMP mitigation option paper, OOP4). Credits for use or sale (e.g., sales within the ETS) can also be acquired through use of tax and/or lease incentives and through the initiatives coming from Small and Large Engine Subgroup (e.g., advanced ignition systems, use of electric engines, centralized large engine from many small engine mode of operations). In addition, opportunities exist for collaboration between engine manufacturers and producers for field testing new engine technology through a swap out program, dirty old for cleaner new. Finally, use of voluntary laboratory testing of a select group of existing engines (e.g. uncontrolled small, <300 hp, engines) could provide a means to identify innovative cost-effective modifications to improve engine efficiency and reduce engine emissions (SERP, 2006).

<u>Benefits</u>: Joint participation by oil and gas, electric power production, and other source category stakeholders provides opportunities for multi-pollutant emission reductions that cover key criteria air pollutants such as NO_x, SO_2, VOCs, $PM_{2.5}$, and PM_{10}. An added benefit could be realized by also including green house gases such as CO_2 and CH_4, in the mix. Examples of the emission reductions that

could be achieved by a well designed and implemented ETS are the 50% reduction from 1980 levels of SO2 emissions from utilities under the ETS within US EPA's Acid Rain Program[1] and the 65% reduction from 1990 levels achieved under the Ozone Transport Commission NOx Program (SERP, 2006).

Tradeoffs: The ETS could be designed to provide for pollutant emission allocation and/or credit tradeoffs (e.g., NOx for SO2 in NOx limited regions) and trades between source groups or categories (e.g., oil and gas NOx with power plant SO_2).

Burdens: The major burden would be administrative in nature. Who would be responsible for designing, setting up and administering the proposed EBETS program and how would it be funded?

II. Description of how to implement

A. Mandatory or voluntary: Participation in the program would be voluntarily.

B. Indicate the most appropriate agency (ies) to implement: The states.

III. Feasibility of the option

A. Technical: The technical feasibility of ETS programs is well established and is in use around the world.

Differing opinion: Accurately and reliably measuring the emissions from oil and gas sources will prove challenging. EBETSs have had broad success because those that have been established rely heavily on good monitoring and reporting, and it is not clear that such techniques are available for the oil and gas sources of interest. Parametric, as opposed to direct exhaust emissions monitoring is one option, but the less direct/accurate/reliable the measurement, the more likely it is that some offset/discount will be demanded to make up for the uncertainty, e.g., if a source wanted to purchase credits as part of its compliance plan, it would have to purchase two instead of one. Alternatively, sources with relatively weaker emissions monitoring would be allowed to purchase credits, but not sell them. This latter approach was taken in the WRAP SO2 Backstop Trading Program.

B. Environmental: The feasibility in achieving significant emission reductions has been clearly demonstrated through use of well designed and implemented ETS programs. Inclusion and addition of "Best Management Practices," innovative technologies, improved maintenance and other pay-back incentives enhance the feasibility of achieving emission reductions required to meet air quality and visibility enhancement goals in the Four Corners Region.

C. Economic: This program is economically feasible because emission trading provides economic incentives through implementation of complementary voluntary measures that reduce emissions, provide fuel savings, reduce operation and maintenance cost by adoption of BMPs and installation of innovative technologies. One recent study of projected economic gain by 2010 from the continued implementation of the ETS within the Acid Rain Program estimated it would provide an annual economic benefit of $122 billion (in 2000 $) at an annual cost of approximately $3 billion (or a 1 to 40 cost-benefit ratio).

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[1] The success of the Acid Rain Program ETS is evident from emissions data, which shows that SO_2 emissions were reduced by over 5 million tons from 1990 levels or about 34 percent of total emissions from the power sector. When compared to 1980 levels, SO_2 emissions from power plants have reduced by 7 million tons or more than 40 percent.

IV. Background data and assumption used

1. United States Environmental Protection Agency (USEPA) Acid Rain Program < http://www.epa.gov/airmarkets/arp/index.html>
2. Illinois Environmental Protection Agency Emission Reduction Market System (ERMS) <http://www.epa.state.il.us/air/erms/>
3. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006.
4. Chicago Climate Exchange < http://www.chicagoclimatex.com/>

V. Any uncertainty associated with the option Medium to high.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

A key crossover issue to establishing and implementing an effective EBETS is the facilitation of voluntary participation of electric utilities and other major source groups. This will provide the anticipated needed trade-offs in air pollutants (e.g., NOx and SO_2) that participation by one or a limited number of source groups may not be able to provide.

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation

I. Description of the mitigation option

This option provides for regulatory agencies and industry working together to utilize various legislative (state/federal/tribal) processes to achieve real emissions reductions. Emission reductions would be achieved by providing economic incentives that would encourage the industry to utilize lower emission internal combustion engines in various applications.

Emission reductions could be achieved through reducing the number of trucks in the field. This could be accomplished by providing incentives for companies to install underground piping in order to dispose of produced water. Criteria pollutants could be reduced by installing lower emissions compressor engines. Industry could be encouraged to install such engines by implementing tax incentives as described below.

Tax incentives provide economic relief to industry by reducing or eliminating taxes on certain equipment or activities. The equipment or activity must provide a recognized environmental benefit to the taxing entity that grants the incentive. Some examples of tax incentives currently being utilized are: (1) allowing costs of retrofitting existing engines or installing new engines to be fully deducted in the year they are incurred rather than being capitalized (2) tax credit certificates issued to program participants, which can be redeemed over a specified period of time (3) income tax credits upon installation of approved equipment.

The air quality benefits include net reduction of emissions, primarily of nitrogen oxides. However, reductions in sulfur oxides, greenhouse gas emissions and particulate matter emissions can also be calculated. Only positive environmental impacts have been identified. It is not anticipated that this strategy would cause any negative impacts, other than increased costs to industry. This strategy specifically provides for relief from such economic impacts.

Economic burdens include the cost to the oil and gas industry, engine manufacturers and other interest groups to develop and lobby legislative proposals. New technology would be more efficient, possibly resulting in increased production and reduced costs. The increased revenue would provide some offset to the initial costs of installation or retrofitting. Economic burden to the taxing entity would also occur. The taxpayers would, in effect, be subsidizing industry efforts to install or retrofit equipment to achieve lower emissions. Achieving taxpayer approval for such a subsidy might prove difficult.

Assistance from the Cumulative Effects Work Group could be helpful in estimating the potential cost-benefit of this option.

II. Description of how to implement

A. Mandatory or voluntary: Participation by industry or other groups would be voluntary, both in working to establish tax/economic development incentives and in taking advantage of such incentives.
B. Indicate the most appropriate agency(ies) to implement**:** States of Colorado and New Mexico. Counties of San Juan, NM; La Plata, CO; and other counties in the Four Corners area of impact. Indian tribes, including Jicarilla, Ute Mountain Ute, Southern Ute, Navajo, and others. These groups would need to work with state legislatures and/or Congressional representatives in getting sponsors to help draft an energy bill that includes tax incentives for improving Four Corners air quality.

III. Feasibility of the option

A. Technical: Many models of tax and economic development incentives are available. A list of some models follows, with more details contained in an Appendix to this document.

i. Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm

ii. Brownfields Tax Incentive (1997 Taxpayer Relief Act P.L. 105-34). This model allows costs to be fully deductible in the year they are incurred, rather than having to be capitalized.

iii. New York State Green Building Initiative. This tax credit program was developed by New York State Department of Environmental Conservation as per 6NYCRR Part 638. Tax credit certificates are issued and can be redeemed at any time over a designated period (i.e. 2006 – 2014).

iv. Montana Incentives for Renewable Energy include property tax exemptions, industry tax credit, venture capital tax credits, and a low interest revolving loan program, special revenue local government bonds, and streamlined permitting processes for participants, income tax credits for retro-fitting equipment.

v. State of Virginia House Bill 2141, July 1997 allows the local governing body of any county, city, or town, by ordinance, to exempt, or partially exempt property from local taxation annually for a period not to exceed five years.

vi. US EPA's Voluntary Diesel Retrofit Program is a non-regulatory, incentive-based, voluntary program designed to reduce emissions from existing diesel vehicles and equipment by encouraging equipment owners to install pollution reducing technology. This option would easily fit into the "partnership" mitigation option. However, it is also a model for the type of equipment that might qualify for a tax incentive.

vii. Philippines Department of Natural Resources developed a single document that consolidates all tax incentives for air pollution control devices. Not new incentives, but a compilation of existing programs.

viii. Western Regional Air Partnership diesel Retrofit program for diesel engines could be used as a model for other internal combustion engines. The guidance document for developing a retrofit program is found on the WRAP website. See Appendix for information. This option would easily fit into the "partnership" mitigation option. However, it operates similar to a tax incentive program and gives an example of how to set up a workable program.

B. Environmental: The environmental benefits of pollutant emissions reductions are well documented.

C. Economic: The entire concept of this mitigation option is that it must be economically viable.

IV. Background data and assumptions used

See Appendix for background studies.
Cooperation between the regulated community; local, state and tribal governments; and equipment manufacturers would have to be garnered in order for this option to work.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

The three member drafting team expressed no disagreement with this option.

VII. Cross-over issues to the other source groups

These tax incentive programs could also apply to other sources, such as power plants or vehicles.

APPENDIX

Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm This model can be used to show the effects of all tax incentives previously granted, as well as the effects of hypothetical tax incentives or tax relief that might be considered in the future. Impacts include reduction in taxes; increased production; effects on federal, state and local government revenues.

Brownfields Tax Incentive fact sheets (EPA 500-F-03-223, June 2003) and incentive guidelines (EPA 500-F-01-338, August 2001) can be found on US EPA's website at www.epa.gov/swerosps/bf/bftaxinc.htm There are also numerous case studies listed on this site as well as federal resources.

New York State Green Building Initiative credit certificates can be re-allocated to secondary users, if the initial recipient cannot utilize the entire credit amount. Information available at www.dec.state.ny.us/website/ppu/grnbldg/index.html or Pollution Prevention Unit (518) 402-9469; NY business tax hotline (518)862-1090 x 3311

Montana Incentives for Renewable Energy http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp

Virginia property tax exemptions for the Voluntary Remediation Program http://www.deq.state.va.us/vrp/tax.html

US EPA's Voluntary Diesel Retrofit Program information at http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm Includes a list of approved retrofit technology.

Philippines Department of Natural Resources lists many tax incentive and economic incentives at http://www.cyberdyaryo.com/features/f2004_0624_03.htm Also included are numerous links to related sites.

Western Regional Air Partnership guidance document for diesel retrofit programs can be found at http://www.wrapair.org/forums/msf/offroad_diesel.html

Mitigation Option: Voluntary Partnerships and Pay-back Incentives: Four Corners Innovation Technology and Best Energy-Environment Management Practices (IBEMP)

I. Description of the mitigation option

This option encourages establishment of partnerships between oil and gas producers and federal, state and local agencies and with engine manufacturers. Examples of such voluntary partnerships that have worked successfully in reducing emissions and providing cost benefits to industry include the U.S. EPA's Natural Gas STAR Program, the New Mexico's Voluntary Innovative Strategies for Today's Air Standards (VISTAS) Program, Green Power and Combined Heat and Power Partnerships. The Natural Gas STAR Program is one of many voluntary programs established by the U.S. Environmental Protection Agency (EPA) to promote government/industry partnerships that encourage cost-effective technologies and market-based approaches to reducing air pollution. There are seven San Juan Basin producers[1] that are currently active members of the Natural Gas STAR Program. The VISTA Program is modeled after Natural Gas STAR.

This option involves establishing new partnerships or extending existing partnerships that encourage voluntary measures that reduce emissions and provide industry payback through improved operation and maintenance efficiencies. The IBEMP option is based on and is intended to extend upon the successes achieved in EPA's Natural Gas STAR Program and to complement the newly established VISTAS Program.

The central ideas of this option

- Increasing efficiency will result in more productivity, less emission, and increased revenue.
- Complementing EPA's Natural Gas STAR Program and VISTAS program to focus on the pollutants not covered in these programs
- Collection and use of the Best Management Practices (BMPs) from around the world, latest innovative technologies, and innovative solutions found by IBEMP members.

The air quality benefits include reduction of criteria pollutants such as NOx, SO_2, $PM_{2.5}$, PM_{10} as well as green house gases CO_2 and CH_4. The success of the EPA's Natural Gas STAR Program is well documented. According to the EPA's Gas Program, "Since the Program's launch in 1993, Natural Gas STAR Partners has eliminated more than 220 billion cubic feet (Bcf) of methane emissions, resulting in approximately $660 million in increased revenues." One Natural Gas STAR Partner has achieved the 18% to 24% fuel saving and reduction of 128 Mcf of methane emission per unit per year after installing an automated air to fuel ratio (AFR) control system called REMVue. According to engine manufacturers, new generation engines have benefits over older generation such as low operating cost, high thermal efficiency, low emissions, maintenance simplicity, and low repair cost which will help in recovering the cost of investment faster. An example of rapid improvement in the engine technology is the new Cummins-Westport engine, which is capable of peak thermal efficiency of close to 40% with 0.01 g/bhp-hr PM and 0.2 g/bhp-hr NOx emission. Even though Cummins-Westport engines and new generation engines from other engine manufacturers are geared towards transportation sector at present because of tighter emission standards, the improved engine technologies will help reduce the pollution in the other industrial sectors as the demand grows for efficient engines.

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[1] BP, Burlington Resources, ConocoPhillips, Devon Energy, Williams Production, Energen Resources, and XTO Energy

Under this option, the time period to offset the cost of the replacing old engines with a new generation engines can be estimated through analysis of data from laboratory testing. Such data may be available from engine manufacturers or obtained through independent laboratory engine performance tests. The voluntary comparative laboratory performance and emissions testing (e.g., operating cost) and documentation would be performed by an independent test laboratory. In addition, voluntary laboratory and field-testing of a select group of existing engines (e.g., uncontrolled small, < 300 hp, engines) could provide a means to identify cost-effective modifications to improve engine efficiency and reduce engine emissions (Lazaro 2006, SERP).

Under this program the increased revenue from methane mitigation and fuel and maintenance savings can offset the cost of investment in the BMP and new technologies or equipment. In addition, under the proposed IBEMP option, partner members' mitigation efforts will be fully recognized and promoted similar to the recognition of partner contributions under EPA's Natural Gas STAR Program and New Mexico's VISTAS Program. Mitigation efforts can be recognized through awarding of emission credits (which can be traded in an emission market system, OOT-3). These efforts will also provide benefits to members through improved public and investor relations.

Since the IBEMP option is a voluntary program, participating members will have control or choice on mitigation decisions that are made. This provides opportunities for choices that provide a return on investments in best management practices and on new equipment and technology. As such, this option does not impose a burden on participating partners. Although, being a partner under this option would not relieve an operator from complying with non-voluntary measures or options, BMPs or other commitments made voluntarily under this option may facilitate compliance with other mandatory measures that may be adopted or come into play.

II. Description of how to implement

A. Mandatory or voluntary: The participation in the program is voluntarily

B. Indicate the most appropriate agency(ies) to implement: Through the New Mexico Environment Department under or a part of its VISTAS Program and/or in partnership with the Colorado Department of Public Health and Environment. The USEPA Gas Program may also be interested in collaborative partnerships with the Four Corners Air Quality Task Force.

III. Feasibility of the option

A. Technical: The success of the EPA's Natural Gas STAR Program is a clear indicator of the technical feasibility of this program.
B. Environmental: The Best Management Practices, including equipment upgrades are well established in the oil and gas industry and adoption of these measures will provide opportunities for significant and achievable emission reductions.
C. Economic: This program is economically feasible because innovative technologies and BMPs will result in increased productivity, fuel saving, and environmental benefits, which in return offset the cost of investment. The previously referenced EPA Natural Gas STAR Program example illustrates that significant savings can be achieved in reduced fuel consumption (e.g., in one case that covered 51 engines reduction in excess of 2,900 MMcf or an average of 78 Mcf per day per engine, when adjusted for load, was achieved over a two-year period). The final payout period was 1.4 years by taking into consideration of fuel saving of $4.35 million at a nominal value of $3/Mcf.

IV. Background data and assumptions used

1. United States Environmental Protection Agency (USEPA) Natural Gas STAR Program <http://www.epa.gov/gas/>

2. New Mexico San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) <http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html>
3. Engine Manufacturers: <www.cat.com>, <www.cummins.com>, <www.cumminswestport.com>.
4. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006
5. Near-term commercial availability of small clean efficient engines
6. Near-term commercial availability of advanced engine technology

V. Any uncertainty associated with the option Low to medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

Establishing and implementing an effective IBEMP is the facilitation of voluntary participation of San Juan oil and gas producers. There are no key crossover issues with other source groups.

Mitigation Option: Voluntary Programs

I. Description of the mitigation option

Overview
This option describes voluntary programs to implement mitigation strategies and achieve air quality benefits that are above and beyond the requirements of regulations and permits. This option is not meant to replace the *Voluntary Partnerships and Pay-back Incentive* mitigation option, nor is this option meant to indicate voluntary implementation should be applied to existing or future requirements necessary for improvement of air quality. There are situations in which mandatory measures are the only system that will result in emissions reductions that are high-impact, consistent, and necessary. There are also situations in which voluntary implementation of strategies may be a method to achieve emissions reductions in a time- and cost-effective manner. Voluntary programs allow participants to demonstrate their commitment to the issue and to local communities. Challenges to success with voluntary programs include publicizing a program to make it well-known, creating a list of strategies and technologies that may be implemented voluntarily, offering incentives sufficient to attract program participants, and quantifying emissions reductions adequately and consistently to estimate results.

Air Quality and Environmental Benefits

- Air quality improvement because voluntary measures would achieve emissions reductions beyond regulatory and permitting requirements.
- Depending on strategy/technology, other environmental benefits may exist.

Economic

- Capital investment from participants for voluntary measures and reporting.

Trade-offs

- Air quality improvement
- Positive public relations
- Agency's costs for administration and tracking.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary. The New Mexico Environment Department already administers a voluntary program called VISTAS (Voluntary Innovative Strategies for Today's Air Standards) that is modeled after EPA's Natural Gas STAR Program. To increase implementation, the agency could compile of list of mitigation options not otherwise required by regulation or permit, as a list of "qualifying" voluntary measures for VISTAS. More information about VISTAS is available at: http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html. Quantification of benefits and measurement of other results is essential to ensure accountability in a voluntary program and increase likelihood of success of the program. In addition, participants or the administrator of a voluntary program should describe voluntary actions by producing "Lessons Learned" papers, which are short descriptions of practices and technologies employed, benefits and challenges, feasibility, and implications for future use of the same voluntary actions.
B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies

III. Feasibility of the option

A. Technical: Good feasibility due to flexibility and choices regarding participation and specific technology(ies) implemented. Potential voluntary measures for the oil and gas industries may include, but are not limited to, the following:

- Plunger lift cycles for removal of liquid buildup and minimizing well blowdowns.
- Device on tanks to control over-heating, such as bands of insulation.
- Electrification where possible.
- Centralization of tank batteries to decrease truck traffic.

B. Environmental: Excellent feasibility, however environmental benefits depend on control strategies. Select control strategies may have other air or non-air environmental impacts, such as SCR's ammonia slip.

C. Economic: Feasibility depends on incentives. Economic feasibility often increases in response to incentives. Participation in voluntary programs for companies is often based on a cost/benefit economic analysis, and incentives can provide a deciding factor. Potential incentives would be determined by the implementing agency and may include the following:

- “Good Citizen” marketing
- Alternative to regulation, if any exist
- Paybacks/savings
- Consideration for expedited permits, if possible
- Parametric monitoring less strict or other requirement leniency, if possible
- Tax credit/royalty rate reduction
- For Federal land, modification in standard stipulations, if possible.
- “Credit” given like an Environmental Management System on compliance history

IV. Background data and assumptions used

Natural Gas STAR and San Juan VISTAS, both voluntary air programs in the Four Corners region.

V. Any uncertainty associated with the option High. Voluntary programs do not guarantee emissions reductions, nor are emissions reductions enforceable. Quantify of reductions through reporting may lessen uncertainty but do not guarantee or enforce reductions.

VI. Level of agreement within the work group for this mitigation option Medium. This option write-up stems from a discussion at the November 8, 2006 meeting of the Oil and Gas Work Group.

Some members of the work group expressed concern that mandatory application of the strategies outlined in this document prior to analysis by a regulatory agency may preclude consideration of advantages and disadvantages from voluntary programs. There was also some discussion of the concept of criteria for establishing whether a mitigation strategy is applied under voluntary or mandatory conditions should be developed to enhance capability for implementation of the options. These criteria would provide an important tool to agencies considering options by better defining feasibility. Additionally, voluntary application of the mitigation strategies would facilitate the development and efficient implementation of these options via a “lessons learned” approach where mandatory application may prematurely dictate the method of implementation.

VII. Cross-over issues to the other source groups

If a voluntary program has a wide range of participants, there are many cross-over issues to other source groups in terms of what voluntary measures could be implemented by those sources.

Mitigation Option: Cumulative Inventory of Emissions and Required Control Technology

I. Description of Mitigation Option

The Four Corners Region is a hotbed of oil and gas activity. There are more than 20,000 oil and gas wells in the San Juan Basin and at least 12,500 additional new wells are proposed within the next 20 years. Oil and gas facilities are being located in remote areas and in neighborhoods and cities. The City of Bloomfield, NM, population of 7,200 people, has at least six major oil and gas processing facilities in very close proximity. A large elementary school near the cluster of these facilities north of Bloomfield was evacuated in 2006 due to an accidental release of noxious emissions from one of these gas plants.

A cumulative inventory of total emissions from the large oil and gas facilities near densely populated areas should be conducted prior to the permitting of additional facilities. It has been reported that at least one new, large, petroleum processing facility is on the drawing board for the Bloomfield area.

All oil and gas facilities, large or small, should be required to report all emissions to appropriate governing agencies annually. A cumulative inventory of emissions is necessary.

Installation of best available technology emission control equipment on ALL oil and gas facilities should be MANDATORY to greatly reduce the release of pollutants into the environment. All internal combustion engines should be required to be fitted with catalytic converters.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: States of New Mexico and Colorado.

III. Feasibility of the option

A. Technical: is not clear whether the intent was to have a yearly report of emissions output based on continuous emissions monitoring for all pollutants (very expensive), or if the intent was to have the operators estimate the amount of emissions based on what sources had been operational during the year. Option also needs to define what levels of the given pollutants would be acceptable to assess feasibility.
B. Environmental: None
C. Economic: None

IV. Background data and assumption used

Bloomfield area ozone levels are already periodically high according to monitoring. Any consideration of permitting additional large oil and gas facilities near Bloomfield should include risk of increasing levels of ozone.

An example:
The North Crandall Compressor Station located within the City of Aztec is permitted by NMED Air Quality Bureau at 176.3 tons/yr (tpy) of Nitrogen Oxides (NOX), 39.4 tpy of Carbon Monoxide and 75.9 tpy of Volatile Organic Compounds (VOC's). There is a warning sign on the fence that states "Warning Hazardous B.T.E.X. emissions may be present." B.T.E.X. compounds are toxic to humans and wildlife. Several homes are located near this facility.

In comparison to the refineries and gas processing facilities in the Bloomfield area, the Williams Crandall Compressor Station is small but it is permitted to emit about 292 tons of pollutants per year into the atmosphere. Cumulative permitted emissions from the very large Bloomfield facilities are unavailable at this time.

Oil and gas facilities are sources of many hazardous pollutants such as NOX, SOX, VOC's, methane, hydrogen sulfide, etc. Many of these pollutants contribute to respiratory diseases, cardiac diseases and some of them are carcinogens. Hydrogen sulfide is a deadly neurotoxin.

V. Any uncertainty associated with the option None.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Mitigation of Hydrogen Sulfide

I. Description of Mitigation Option

Hydrogen sulfide (H2S) is a deadly neurotoxin. Since H2S contamination is becoming more widespread, for the safety of the public and the oilfield employees ALL wells should be tested for H2S by the well operators at least twice per year and the test results reported to appropriate agencies.

The companies provide H2S training and monitors for the employees. The employees are trained to be aware of H2S, but the general population is not. The typical rotten egg smell is a familiar warning to oilfield employees, but the general population who lives in close proximity to H2S wells are not informed about the dangers of an H2S release.

Public information programs on the dangers and toxicity of oil and gas pollutants and most importantly H2S, must be made available to the people. Ideally, gas wells and refineries should be isolated away from the general population; however, oil and gas facilities are being established in populated areas and vice versa. Houses are being built next to oil and gas sites. For the health of the public, exposure to H2S and other petroleum related toxics must be prevented.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: The companies and the States of New Mexico and Colorado.

III. Feasibility of the option

Not considered.

IV. Background data and assumption used

For H2S information, do a Google search on Dr. Kaye H. Kilburn MD, and Professor of Medicine at the University of Southern California. He is a leading researcher on chemicals such as hydrogen sulfide and diesel exhaust.

The Bureau of Land Management has been collecting data on the wells contaminated by hydrogen sulfide in the San Juan Basin.

Quick statistics are as follows:

- More than 375 wells test positive for H2S
- H2S is present in at least 5 formations
- 11 producers have reported H2S wells
- A lot of the small producers did not report, so these numbers are likely higher.

Sour gas (H2S) fields are common in Colorado and New Mexico. New Mexico has a State Regulation with an ambient air quality standard for H2S; however, it is reported that NMED does not have H2S measuring equipment. H2S must be closely monitored and controlled by the companies and the State and Federal agencies. It can be deadly.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Encourage States Importing San Juan Basin Natural Gas to Require Pollution Control at the Source

I. Description of the mitigation option

States that import San Juan Basin natural gas should require the gas be produced and transmitted in an environmentally clean method. End users should have a responsibility for the sources of pollution generated from natural gas production.

Recent California legislation banning importation of power from sources that generate more greenhouse gases than in-state natural gas-fired plants leads to this related issue.

Much of the natural gas used in these plants as well as in the residential sector is imported from other states or other countries. One published article[1] states that 85% of the natural gas used in California is from out-of-state and that one-quarter of this comes from the San Juan Basin. Other states may also be using San Juan Basin natural gas. It is disingenuous for states to claim to be producing clean power or using clean gas for residential use when the production of fuel for that "clean" power plant or clean burning appliance is creating serious air and water quality problems at the source of the fuel. If the user states are seriously concerned about improving air and water quality they should address out-of-state impacts as well as in-state impacts.

II. Description of how to implement

A. Mandatory or voluntary:

Adoption of a "clean fuel import policy" by user states would necessarily have to be voluntary. However, the application of such a policy by a user state, once adopted, could and should be mandatory for fuel importers.

B. Indicate the most appropriate agencies to implement:

Implementation of the policy in user states could be by the regulatory agencies or commissions charged with oversight of investor-owned or publicly-owned electric utility systems. In some cases legislation may be necessary to implement this policy.

There is a need to develop an inventory, state-by-state, of customers who are importing natural gas from wells in the San Juan Basin. The first step in implementation would involve contacting user states and urging adoption of policy or legislation requiring importation of "clean" natural gas; a definition of "clean" must be developed.

III. Feasibility of the option

A. Technical:

It may be difficult to develop a good working definition of what constitutes acceptably "clean" natural gas. This is also a legal issue and one must work within the framework of the Federal Clean Air Act and Clean Water Act as well as individual state statutes.

B. Environmental:

Should be feasible

C. Economic:

Could eventually lead to higher costs for electricity in user states due to the rightful inclusion of environmental costs of fuel production.

D. Political:

Could be very difficult to implement in some states

IV. Background data and assumptions used

Assumption that most natural gas produced in the San Juan Basin is exported to other states. The figures cited in Section I should be checked/verified.

V. Any uncertainty associated with the option
Yes; response of user states unknown.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups
Significant cross-over to the Power Plants and Oil & Gas Work Groups

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[1] *High Country News*, Dec. 25, 2006, p. 12.

OIL & GAS: PUBLIC COMMENTS

Oil & Gas Exploration & Production Public Comments

Comment	Mitigation Option
If "many companies BMPs in place already," then why does a mandatory approach to BMPs seem implausible. This should be a cost of doing business in this area; a cost that is well-absorbed by most other companies.	Best Management Practices (BMPs) for Operating Tank Batteries
VRU's have one big technical problem not addressed, the introduction of air in the gas. Air is made up of Nitrogen and Oxygen two contaminates that the gas pipeline companies refuse to take into their system. If one VRU allows air to enter the gas system, then the whole gas system must be shut down or flared in the field. The gas companies must be forced to take air in reasonable quantities into their system. The gas pipelines will argue that it is unsafe, if that is true then all the gas supplying houses in the Colorado front range must be shutdown because air is added to improve quality.	Installing Vapor Recovery Units
In the 60's and 70's this type of water removal was tried in the northern Rockies. The amount of saltwater disposal was huge and the beds may only last a day or two before they must be changed.	Dehydrators / Separators / Heaters
Glycol pumps are a critical item and any replacement system must have a high reliability. 5KW generators will had NOx, CO, CO2 and decrease reliability. Kimray pumps with flash gas separators reduce emissions and keep the system reliable. the gases recovered from the pump gas separator can be used for fuel MOST of the time. In some cases where the gas stream is high in liquefiable hydrocarbons (those with molecular weights higher than 40) the pump gas separator vapors will not burn reliably or completely cause unreliable operators and increased emissions. In the case of gases with high liquefiable content, vent gases need to be flared (burned).	Zero Emissions (a.k.a. Quantum Leap) Dehydrator
We strongly agree that an initial voluntary monitoring effort, followed by mandatory reporting and monitoring requirements, should be initiated by the operators to measure concentrations and species of VOCs and HAPs and other flaring by-products.	Venting versus Flaring of Natural Gas during Well Completions
We strongly agree that co-location and centralization of new oil/gas field facilities should be voluntarily implemented by operators. We also agree with the approach of state and federal agencies and mineral management agencies proactively integrating this approach into planning and permitting processes.	Co-location / Centralization for New Sources
The present laws will not allow this option. TEG (glycol) units must be permitted at a maximum rate. In the Rockies the maximum rate is only required for a few months during the year. Good operators adjust their pumps as needed to save fuel and lower emissions, but they get not credit for doing so because their permits are set. GLYCALC uses all kinds of default assumptions, this does not replace good engineering and the ability to make real life adjustments. Other design and simulation programs should be allowed without any legal ramifications.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Optical Imaging to Detect Gas Leaks

Comment	Mitigation Option
Instrument gas or instrument air is used to control facilities. These controls maintain the emission control system, gas quality controls and safety shutdown systems. If the instruments air/gas system lacks sufficient quantity and quality, the controls will fail and emissions, quality and safety devices can fail with undesirable results. At small and remote sites air compressors will be unreliable and gas must be used.	Convert Gas Pneumatic Controls to Instrument Air

Oil & Gas Stationary RICE Public Comments

Comment	Mitigation Option
The SUGF agrees that new air quality management strategies such as this option should be implemented to address cumulative air quality impacts. It is highly recommended that this option be considered by the regulatory agencies and be applied to both new and existing engines, particularly units of less than 300 horsepower. Although horsepower levels are lower and operating hours may be limited, emission rates of these smaller units are higher than larger units. As a single source, emissions may be minimal, but collectively with other area sources it may have a cumulative affect.	Industry Collaboration
Comments below are specific to the mitigation option as currently written, which assumes the power requirement would come from the power grid. A second alternative is also provided below as a sub option assuming the power comes from on-site generators. We recommend including both alternatives to this option. Comments are also provided on the analysis of this option under the cumulative effects section of the public draft report. Install Electric Compression (re-label as Alternative 1 - Power Grid, see recommended Alternative 2 addition below after comment # 6) 1. The overview is not consistent with overviews written for other mitigation options covered in the Task Force Report. As written, the overview presents a rather biased view on the viability of this option. The overview should provide a description of the option without any discussion about the option's technical or economic feasibility. Possible physical restriction or modification requirements on installation for specific compressors should be removed and discussed under Sec III. Feasibility of the option, A. Technical. The last two sentences on the electric grid should also be moved to the feasibility discussion or deleted. Under the mitigation option overview, we recommend inserting the following: The selection of combustion engines for electric compression should be on case-by-case basis which will allow the flexibility of evaluating necessary compressor interface modifications such as re-gearing to accommodate electric motors. 2. The discussion and emission table under Air Quality/Environment is inconsistent with discussions covered in the other mitigation options and should be deleted. Please see our comments on the Cumulative Effects section analysis of this option. The nationwide averages of emissions from power plants operated by the three identified companies would not be representative of the power supplied from the Western Power Grid. We recommend inserting the following under the mitigation option overview:	Install Electric Compression

Comment	Mitigation Option
The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. 3. The economics as written only covers the costs of the option if implemented. To provide a balance picture both costs and economic benefits should be covered. The following points should be included in the discussion: a. In case of electric motors connected to power grid, there is virtually no maintenance cost. b. The electric rates in the night are cheaper compared to peak times. This will result in additional saving for oil and gas industry. c. The need for less maintenance of electric motors and localized electric grid will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well as minimize impact on the wild area in the four corners region. In the second bullet not sure what specific maintenance and repair costs we be borne by producers that are associated with the electric power source for electric compression. Maintenance and repair of substations and transmission lines, from the grid to substation, are typically borne by electric generators and included in rates to consumers. The last bullet on suppliers/manufacturers is more an implementation issue than an economic issue. We recommend moving this discussion to description on how to implement. 4. Tradeoffs - We recommend striking any reference to new co-generation plants as means to supply power for electric compression, since the electric compression option requires no thermal power. As previously stated current plans for electric power generating within the western regional power grid should be adequate to meet even the most optimal electric compression demand that might develop. 5. Burdens - Since implementation of electric compression is voluntary the producers can evaluate which compressor conversions to electric are economically feasible. Economic burdens over the long term can be minimized and possibly turned into economic gain based on careful evaluation of return on capitol expenditures (e.g., lower electric motor vs. RICE engine maintenance costs). The assumed requirement for new electric power generation to support electric compression is speculative, since the degree of implementation of this option producer specific. We recommend deleting the sentence on capitol investment for new power plants. Also, existing plans for new generation may be sufficiently adequate to meet reasonably anticipated power requirements for implementing this option. We recommend consultation with the Power Plant Workgroup. 6. II. Description of how to implement and feasibility of option - See above comments. 7. III. Feasibility of the option, C Economics - On economics, we agree that costs need to be evaluated, including the economic benefits, as previously mentioned. The need for modeling (air quality) to evaluate the air quality	

Comment	Mitigation Option
benefits is true about all of the options. Also, the planned modeling to address cumulative regional air quality impacts is discussed elsewhere in the draft report. We recommend deleting the sentence. ON-SITE ELECTRIC GENERATOR ALTERNATIVE TO GRID POWERED ELECTRIC COMPRESSION As written the current option identifies only one source of electric power, power from the grid. A second alternative to this option would be to supply power to the electric motors using local dedicated low-emission natural gas lean-burn electric generators. The electric compression using the lean-burn electric generator should be included as a second alternative for the "Install Electric Compression" mitigation option. We recommend that the Four Corners Air Quality Task Force add the following language to the Install Electric Compression mitigation option: Mitigation Option: Install Electric Compression (Alternative - On-Site Generators) I. Description of the mitigation option Overview - As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers." The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc. Air Quality/Environmental Benefits The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx at 900 rpm which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation	

Comment	Mitigation Option
option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines. The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region. Economics The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost. The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines. The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines. Tradeoffs In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible. The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated. Burdens The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. II. Description of how to implement	

Comment	Mitigation Option
A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time. B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies. III. Feasibility of the option A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option. B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines). C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small. IV. Background data and assumptions used The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff. Gas electrical generator information was obtained from Caterpillar's Website. V. Any uncertainty associated with the option (Low, Medium, High): Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies. VI. Level of agreement within the work group for this mitigation option TBD VII. Cross-over issues to the other source groups (please describe the issue and	
The SUGF agrees that implementation of this federally mandated level of emission control will minimize emissions from newly manufactured, modified and reconstructed engines after their respective effective dates.	Follow EPA New Source Performance Standards (NSPS)

Comment	Mitigation Option
The SUGF supports the control technology options listed above as the SUGF supports usage of Best Available Control Technologies on internal combustion engines located within the exterior boundaries of the Southern Ute Indian Reservation.	Use of SCR for NOx control on lean burn engines Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines Install Lean Burn Engines
As EPA commented on the Cumulative Effects Paper, it is unclear how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE are being implemented. The mitigation option <u>Interim Emissions Recommendations for Stationary RICE</u> states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval (COA) for their Applications for Permits to Drill (APD). These limits currently apply only to new and **relocated** engines ... (compressors assigned to the well APD)..." However, we understand that BLM policy for a small engine COA as applied to an APD is for new and **replacement** engines. The Oil and Gas Workgroup should clarify how is the terms "relocated" and/or "replacement" are being defined by BLM and the USFS with respect to COAs for well located engines. For comparison, EPA's NSPS for spark ignition engines will apply to new, modified, and reconstructed units starting in January 2008. The terms new, modified, and reconstructed are defined in Federal Regulation.	Interim Emissions Recommendations for Stationary RICE
We recommend adding the following next generation technology to the four currently included in this mitigation option: Homogeneous-Charge Compression-Ignition (HCCI) technology was analyzed the by cumulative effects workgroup but was inadvertently omitted from the oil and gas work group mitigation option paper Next Generation RICE Stationary Technology. The following is a recommended text for inclusion in the Final Report: Homogeneous-Charge Compression-Ignition (HCCI) Engine I. Description of the mitigation option Overview Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is	Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

Comment	Mitigation Option
the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1] Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. II. Description of how to implement A. Mandatory or voluntary It is too early to determine whether implementation of this technology will be voluntary or mandatory. B. Indicate the most appropriate agencies to implement III. Feasibility of the option A. Technical - HCCI is in the laboratory stage of development. B. Environmental - HCCI has the potential of extremely low NOx levels. C. Economic - HCCI is not sufficiently developed to have proven economic feasibility. IV. Background data and assumptions used 1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript. 2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002. V. Any uncertainty associated with the option (Low, Medium, or High) HCCI has high uncertainty.	

Comment	Mitigation Option
VI. Level of agreement within the work group for this mitigation option VII. Cross-over issues to the other source groups (Please describe the issue and which group.)	

Oil & Gas Overarching Issues Public Comments

Comment	Mitigation Option
The Four Corners Air Quality Task Force (4CAQTF) is a noble way of beginning communication between our citizenry and the polluting industries. Hopefully some meaningful "common ground" can be reached that will produce measurable air quality improvements. With a demonstrated failure of industry to "want to do their best" and when the "dollar gain" in a corporation's quarterly report is the measuring stick for it's shareholders, the recommendations from the 4CAQTF is up against a mature lobby force very capable of stopping meaningful actions that will lead to measurable benefits to our air quality! Therefore, spending serious time deliberating measurable benefits that could predictably occur if industry's suggestion of "year round" drilling EVERYWHERE as a means of ameliorating their emissions to me, seems without merit. A simple catalytic converter on each of their established fossil fuel operated engines would be considered a "wonderful start" of industry wanting "to do their best". Recommending to any state or federal land wildlife management agency to consider removing established seasonal habitat protection bans for the assumed benefit of distributing annual air quality pollutants should not be an option. Many years were spent by land management and wildlife management agencies formulating the habitats that need protection for identified species. The process to establish habitat closures is elaborate. Let us let this industry recommendation respectfully die and encourage installation of catalytic converters on industry's fossil fuel motors. This action does have measurable air quality results. As we drivers know, we are required by law to have catalytic converters on our vehicles as a way of demonstrating our contribution to improving air quality problems. As a recommendation, I would only suggest that if the oil and gas industry wants to recommend the lifting of this seasonal closure on identified lands, that THEY contact the state and federal agencies that have programming prerogatives over habitat and wildlife issues with their suggestion that lifting this ban would have beneficial measurable benefits for air quality concerns that outweigh wildlife concerns. The 4CAQTF should not be the "quarter back" for carrying the recommendation to state and federal habitat and wildlife agencies. I make these comments as a degreed wildlife biologist with 27 years of experience. Respectfully, Warren J. McNall 900 Sabena, Aztec, NM	Lease and Permit Incentives for Improving Air Quality on Public Lands

Comment	Mitigation Option
Disagree - unlike Wyoming, Colorado has a shortage of state and federal specialists to monitor impacts from oil and gas development. As a result, monitoring of oil and gas impacts to wildlife would likely not happen. Streamlining the permit process would be beneficial to operators economically, but may be at the expense of area wildlife and habitat.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Regarding the paragraph: "Monitoring has also not been a model experience in this area. According to reports of a May, 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife." Basically, I would suggest a more neutral approach than the quoted paragraph. It is rather forceful, without sufficient follow-up. It would help our situation if we could see whether the Farmington office is under similar pressures. Alternatively, examining the policies, rather than experiences, might make for a stronger position. For example, as the author seems to know a bit about BLM and permitting--she/he might instead look into the use of categorical exclusions (CAX) which are currently used to circumvent the environmental assessments (EA) that would normally be required to develop well fields on BLM land. (Sometimes this is also called streamlining.) How prevalent is this practice in the Four Corners, do CAX result in a lower standard of environmental review, and could this practice deleteriously impact 4C air quality?	Lease and Permit Incentives for Improving Air Quality on Public Lands
In light of the current global climate conditions, lessening our overall impact on the environment is everyone's duty to the planet and its children's future. This task force should not be in the position of negotiating away wildlife habitat in exchange for mitigating measures that ought to be a duty of the oil and gas industry as a cost of doing business on this planet.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Economic-Incentives Based Emission Trading System (EBETS)

Comment	Mitigation Option
Economic-incentives based emission trading systems (EBETS) have had varying levels of success nationally and have been less successful in geographic regions where pollutants are already causing harm to human health or the environment. It can also be argued that these systems lack incentives to improve environmental quality over economics. They can be more a function of market supply and demand driving the trades, not variations in regional human and environmental health "costs". Multisectoral trading systems are complex, increase challenges in emissions monitoring, and environmental justice considerations become more complicated due to inequitable concentrations of source emissions and different pollutant mixing outcomes. (Regarding the federal Acid Rain Program, indeed, the nationwide level of emissions from electric utilities were halved since 1980, however, no geographic restrictions were imposed and many areas of higher pollution levels remained at higher levels.) As stated in the Task Force document, the major burden for the EBETS mitigation option would be administrative; however the full burden must be assessed and coordinated among the state agencies. Not only would comparability and tracking of different types, sizes and ages of installations be extremely complicated, multi-pollutant emissions trading is challenging to monitor and enforce. Although it would be impossible to have an emissions trading system that eliminates environmental injustice, a carefully designed trading system that is rigorous, far-sighted, and includes geographic restrictions would have a much better chance of reducing localized injustices to human health and/or the environment.	Economic-Incentives Based Emission Trading System (EBETS)
The proposed incentive to modify standard stipulations for federal land if it is to be the relaxing or waiving of seasonal restrictions for wildlife while promoting year round drilling should not be a part of the voluntary program. Seasonal restrictions have been written to benefit wildlife during times of the year when they are at increased risk due to weather, nesting, birthing, etc. The Wyoming experience has shown the potential negative impacts of intense drilling on wildlife, and how highly wildlife is valued by a broad range of American people. With the pressures from the increase in drilling, wells, roads, and pipelines in the Four Corners area, we can ill afford to lose the wildlife protections from the stipulations that we currently have.	Voluntary Programs
New Mexico and Colorado already have rules governing H2S, no need to add more rules that may conflict.	Mitigation of Hydrogen Sulfide
New Mexico Environment Department does have controls for H2S on paper, but state environmental officials have validated that the state does not have H2S monitoring equipment.	Mitigation of Hydrogen Sulfide
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Mitigation of Hydrogen Sulfide
Rules that are capable of being enforced due to adequate staffing and necessary monitoring tools are what is needed to regulate this area. More rules that cloud the issue, or are effectively toothless due to lack of enforcement infrastructure will not accomplish the goals of this task force.	Mitigation of Hydrogen Sulfide

Power Plants

Power Plants: Preface

Overview

The Power Plants Work Group was charged with developing mitigation strategies for existing, proposed, and future power plants in the Four Corners area. For each strategy, one or more work group members provided a basic description of the strategy, ideas for implementation, and discussed feasibility issues to the extent possible.

Participation in the Power Plants Work Group included representatives from state, tribal and federal agencies; industry (including regional power plants); citizens; and interest groups. Ten to 20 participants attended each face-to-face meeting throughout the process. In total, the Power Plant Work Group brainstormed a total of 36 mitigation options and drafted 34. In addition, work group members helped in drafting 18 mitigation options for the Energy Efficiency, Renewable Energy and Conservation section.

Organization

The Power Plants work group initially collected information on existing emissions inventories and emissions projections for existing and proposed power plants. A spreadsheet, called Four Corners Area Power Plants Facility Data Table**,** is located at the end of the Power Plants section and was used as a tool to help supplement mitigation options papers with emissions reduction estimates. The work group divided the remainder of its work into the following categories.

Existing Power Plants: The work group first considered existing power plants, focusing on the two largest power plants in San Juan County: San Juan Generating Station (1800 MW) and Four Corners Power Plant (2000 MW). Eleven mitigation options were brainstormed and drafted for this section. The options drafted ranged from software applications and process optimization to retrofitting NOx and SO_2 emissions control technologies.

Proposed Power Plants: The work group next considered the proposed power plants category. The focus here was on the proposed Desert Rock Energy Project, a 1500 MW coal-fired power plant to be built in Burnham, 30 miles Southwest of Farmington. Options included funding of air quality improvement initiatives and consideration of the Integrated Gasification Combined Cycle (IGCC) process. Four of the 11 comments received on the Power Plants section of the Task Force Report during the public comment process were against building another power plant in the Four Corners area. Desert Rock also submitted comments on the Task Force report. Please see all the public comments pertaining to power plants in an appendix at the end of this section.

Future Power Plants: The work group discussed and documented eight strategies that future power plants could use to mitigate air pollution, including a carbon capture and sequestration (CCS) option, an option for clean coal incentives, large scale renewable energy production, and also an option on nuclear energy production.

Overarching Issues: Finally, the Power Plants report section also has an overarching category for options and ideas that may apply more broadly. Ten options were brainstormed and drafted here, and include mercury pollution mitigation and the Clean Air Mercury Rule (CAMR), cap and trade programs, greenhouse gas mitigation and one calling for a health study.

EXISTING POWER PLANTS: ADVANCED SOFTWARE APPLICATIONS

Mitigation Option: Lowering Air Emissions by Advanced Software Applications: Neural Net

I. Description of the mitigation option

There are many areas of power plant operation where Advanced Software Applications could lower air emissions from current levels. These processes range from the primary power generation equipment, to the various air pollution control devices (APCDs), such as scrubbers, precipitators, baghouses, and SCR units. The best gains in emission reduction couple state-of-the-art APCDs with advanced software applications operating within or in concert with the Distributed Control System, DCS. This mitigation option discusses Neural Network software to lower NO_x emissions at coal combustion low-NO_x burners. Other examples may be found in the Appendix.

Many power plant processes/devices, such as fan speeds, air damper positions, air and coal flows, are automatically controlled by the DCS. The DCS is a networked computer system with "distributed" input/output electronic hardware near the plant control devices, and "live" displays for the control room operators. Given the current state (on/off status or analog value) of every device tag in its database, the DCS uses feedback control algorithms to drive many controlled device variables. Set-points are optimized for the current desired mode of plant operation, such as satisfying a specified megawatt demand at the best possible heat rate.

Neural Networks offer advanced software control by "training" the software to "know" where outputs should be in relation to many inputs. Unlike traditional mathematical equation models, neural networks do not demand intimate understanding of the process. A neural network, sometimes referred to as "fuzzy logic," is a type of "artificial intelligence" statistical computer program, which classifies large and complex data sets by grouping cases together in a manner similar to the human brain. Neural networks "learn" complex processes by analyzing their performance data.

San Juan Generation Station (SJGS) is currently working with a predictive neural network on Units 1 and 2 to lower NO_x emissions. This advanced software application, provided by the DCS vendor, minimizes NO_x formation by optimizing air flow to the burners (e.g., optimal flame temperature). SJGS is gaining experience with this type of software, anticipating the installation of state-of-the-art low-NO_x burner hardware. When these burners are installed on all units, increased reductions in NO_x are anticipated. Neural network software results in lower NO_x emissions than if the burners were controlled by standard DCS software alone.

The neural network uses inputs from the NO_x and O_2 CEMS, Carbon Monoxide (CO) emissions, burner air, secondary combustion air, coal flow, flame temperature, fan speeds, damper positions, etc. There could be dozens of inputs. The network is trained to identify the relative contribution of each process input to NO_x formation as measured by the CEMS. The network is trained across varying modes of plant operation – full load, partial load, startup, etc. at the lowest possible NO_x emissions. Then, as the generating unit operates in various modes, the neural network predictions refine the control actions the DCS would take on its own. This refinement lowered NO_x emissions by approximately 25% at an Entergy coal fired plant (Intech, July 2006 – "Netting a Model Predictive Combo").
Note: CO_2 readings do not correlate significantly to NO_x control. Inputs from the NO_x, CO, and O_2 CEMS are used.

Benefits: NO_x reductions of 10% – 30%. Earn NOx Trading Credits as future regulations may require. Another important benefit is that tighter process controls from the neural network may improve the plant heat rate. When the heat rate improves, less energy is needed to maintain required MW load. With less associated stack gas volume for that load, all pollutant emissions decrease.

Trade-offs: Neural network cannot adapt to unforeseen upsets for which it was not originally trained. Neural net refinement control may have to be removed in these situations.

Some existing boiler controls may need to be automated so the neural network can act on them via the DCS. There are significant associated hardware, software, and labor costs. In combustion control schemes, optimizing NO_x for lowest emissions generally increases CO. CO emissions might increase because the neural network allows CO to ride very close to its regulatory limit. Without the network, CO is manually controlled to a lower level providing a cushion for upsets.

Software is processor-intensive.

Burdens: Cost of software application, more powerful computer hardware, “training” labor. Cost of upgrading some of the other controls on the boiler. The neural net is not much good unless it can actually adjust the equipment such as dampers, burner air registers, fan speed, etc. The controls have to be automated and have to be compatible with the neural net.

II. Description of how to implement

A. Mandatory or voluntary:

This option is being considered by San Juan Generating Station as part of consent decree to reduce NO_x emissions. It may be a viable option for FCPP. There may be some grants available to help fund such upgrades to existing power plants in Four Corners area.

FCPP has also installed neural networks and is gaining experience with process and emissions optimization. Desert Rock’s potential use of this option is unknown.

B. Indicate the most appropriate agency(ies) to implement:

Federal, State, Tribal regulations should not specify specific control strategies, but rather impose emission limits reasonable for modern control strategies. Grandfathering of plants under NSR for installing enhanced controls, is another debate. However, if Federal NO_x budget trading is extended to this area under a Clear Skies option, the economic incentive of expensive NO_x trading credits to either buy or sell would encourage the final emissions control step of “advanced software applications” to realize optimum economic and environmental benefits.

Differing Opinion: Using NOx Budget trading and other grand fathering strategies do not address the pollution problems associated with old, out of date coal fired power plants. The Four Corners Power Plant is the top emitter of NOx in the Nation. Two coal fired power plants with high levels of emissions are located in the Four Corners. Grand fathering should not be an option. Extensive emissions clean up and control is necessary.

III. Feasibility of the option

A. Technical: Neural network technology is a viable control approach well established in many industrial process settings, but requires intensive computational capability. Powerful, cost-effective computers of recent years have facilitated growth of this technology. Due to some limitations to this control strategy, it takes its place with other advanced control strategies, such as Model Predictive Control.

B. Environmental: Environmental impacts are incidental, such as increased power consumption for more powerful computer hardware.
The point of this option is more efficient operation and thus lower emissions.

C. Economic: Software costs and labor are reasonable in light of the long term emission reductions attained. Generally, software costs are much less than capital expenditures for physical APCDs.

The Monitoring Work group asked if additional CEM or other technology be required to operate as part of the neural net feedback loop. SJGS and FCPP have existing NO_x CEMS to meet state and federal Acid Rain Program monitoring requirements. Acid Rain requires a high level of data quality assurance, including daily calibrations. A neural network continues to function upon loss of one or more inputs, within statistical limits. NO_x minimization control would continue during occasional loss of the NO_x CEMS input.

IV. Background data and assumptions used:

ISA Intech article
Information from San Juan Generating Station
There are many other sources of relevant information, including AWMA, Argonne, DOE.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups

Advanced Software Applications, including neural network control technology, could apply to sources in the Oil and Gas sector

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EXISTING: BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Mitigation Option: Control Technology Options for Four Corners Power Plant

I. Description of the mitigation option

Summary of Option

Presumptive Best Available Retrofit Technology (BART) emission limits for SO_2 should be applied to all units at Four Corners Power Plant (FCPP). Presumptive BART emission limits for NO_x should be applied to Units 1, 2 and 3; and combustion controls and Selective Catalytic Reduction (SCR) on Units 4 and 5. When BART for PM10 at FCPP is analyzed, the regulatory authority and the facility should consider the control level achieved at San Juan Generating Station.

Background: Best Available Retrofit Technology (BART)

The Four Corners Power Plant consists of five pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Because the two smaller units (#1 & #2, each at 190 gross MW) are subject to BART and are close in capacity to EPA's 200 MW threshold, the rationale for applying presumptive limits should hold for those units as well. Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 190 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 190 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 253 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu
- Unit #5 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu

Background: FCPP Emissions

In the 1980s, Arizona Public Service (APS) installed venturi scrubbers on Units 1-3, and early generation spray tower scrubbers—but with significant stack gas bypass—on Units 4 and 5. In 2003, APS began a program to further reduce SO_2 emissions at FCPP by eliminating most stack gas bypass. APS succeeded in bringing emissions down from a 30-day rolling plant wide average of 0.44 lb/mmBtu in 2003 to 0.16 lb/mmBtu by 2005, with further improvement to 0.14 lb/mmBtu; this represents a removal efficiency of 92 percent. Although NO_x and PM_{10} emissions were not addressed in that effort, NO_x emissions have been reduced slightly, but FCPP is still the largest emitter of NO_x among coal-fired power plants nationwide.[1] The current rate at which FCPP emits NO_x is approximately 0.54 lb/mmBtu.

The FCPP is located on the Navajo Reservation, and was previously regulated by emission limitations set by the State of New Mexico. The Tribal Authority Rule, however, generally stated that state air quality regulations could not be enforced against facilities on the Indian reservation. EPA, therefore, has to issue federally enforceable emission limitations for FCPP. On August 31, 2006 EPA Region 9 proposed a Federal Implementation Plan (FIP) to establish federally enforceable emission limits for SO_2, NO_x, total PM, and opacity. The proposed FIP would require 88 percent removal of plant wide SO_2[2] on an annual rolling average basis. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016.[3] The proposed FIP would require NO_x emissions not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5.

The Four Corners Power Plant is located on the Navajo Reservation and the Tribal Authority Rule has stated that state air quality regulations could not be enforced against facilities on the Indian Reservation. It is imperative that a firm agreement between the Navajo Tribe and the Federal EPA be negotiated to guarantee that the Federal EPA will be the regulatory and enforcement agency for the Four Corners Power Plant (FCPP) clean up process. This will allow the Federal EPA to regulate and enforce emission limits for SO2, NOx, PMs and opacity that are specified in the new EPA Region 9 FIP.

Update: On April 30, 2007, EPA Region 9 finalized a Federal Implementation Plan (FIP) that establishes federally enforceable emission limits for SO_2, NO_x, total PM_{10} and opacity. The FIP requires 88 percent removal of plant wide SO_2 on an annual rolling average basis, and limits three-hour average SO_2 emissions to 17,900 lbs/hr plant wide. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016. The FIP requires that 30-day rolling average NO_x emissions are not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5; and daily NO_x emissions are not to exceed 335,000 lbs. PM emissions are limited to 0.050 lbs/mmBtu, and opacity is limited to 20%, except for one six-minute period per hour not to exceed 27%.

Presumptive BART at FCPP

Sulfur Dioxide

The application of presumptive BART limits for SO_2 on Units 1-5 at FCPP would result in a plant wide annual average of 0.15 lbs/mmBtu or 93 percent removal based on future coal. Estimated emissions for 2018[4] are shown in Figures 2 & 3 for emissions at the current level of control, the proposed level of control under the FIP, a scenario with BART applied to Units 3-5 only, and BART applied to Units 1-5. All options assume control efficiency remain constant within each given scenario.

Emissions under the scenario where presumptive BART for SO_2 is applied to all Units are only slightly less than current emission rates. However, applying presumptive BART for SO_2 would result in an emission limit specified as an allowable rate of emissions (lbs/mmBtu). The FIP would allow SO_2 removal to decline from the present 92 percent to 88 percent. Additionally, the FIP specifies the SO_2 limit in terms of efficiency, or percent removal of SO_2 from the coal being burned. If the coal quality decreases (to higher sulfur coal), as it is projected to do, the limit in terms of percent removal will allow for more emissions of SO_2; thus, it is preferable to have an emission rate as the controlling limit.

Nitrogen Oxides

The application of presumptive BART limits for NO_x on Units 1-3 (0.23 lb/mmBtu), and combustion controls and SCR on Units 4 & 5 would result in a plant wide annual average of 0.16 lb/mmBtu. Application of presumptive BART for Units 4 & 5 would result in a rate of 0.45 lbs/mmBtu for those Units. Estimated emissions for 2018 are shown in Figure 4 for emissions at the current level of control, the current Title V permit limit, the proposed level under the FIP, a scenario with BART applied to Units 1-5, and a scenario that applies BART to Units 1-3 and applies combustion controls and SCR to Units 4 & 5. NO_x emissions under the proposed FIP would be significantly higher than current rates; application of presumptive BART for NO_x to all Units would reduce NO_x 30 percent from current rates; application of presumptive BART to Units 1-3, and combustion controls plus SCR on Units 4 & 5 would result in the most significant reductions of NO_x: 70 percent from current rates, and less than half from the scenario with BART on all Units.

Since Units 4 and 5 are cell burners, they are inherently very high emitters of NO_x, and, because of the narrowness of their furnaces, are very difficult to reduce emissions by combustion controls alone (combustion controls alone represent presumptive BART). EPA has recognized that the presumptive limits (and associated technologies) do not preclude the application of different technologies: "[b]ecause of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. . . . Our presumption accordingly may not be appropriate for all sources."[5] The cost (see below) of SCR on these Units is comparable to combustion controls—which may not be technically feasible—and SCR will result in significantly more reductions of NO_x. Currently, Units 4 and 5 each emit twice the NO_x as Units 1, 2 and 3 individually.[6] Therefore, SCR is the best reasonable method to achieve meaningful NO_x reductions at Units 4 and 5.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 52 km away from FCPP. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is EPA Region 9.

III. Feasibility of the option

FCPP is currently at or below the presumptive BART limit for SO_2. No additional controls are needed.
Differing Opinion: FCPP does not consistently operate at or below presumptive BART limit for SO_2

For Units 1-3, the Environmental Protection Agency's suggested presumptive BART for NO_x limits "reflect highly cost-effective technologies."[7] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet presumptive NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[8]

Application of EPA's Cost Tool model for Units 4 & 5 predicts that NO_x could be reduced by 70% to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed.[9] EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11_state_EGU_analysis" projections.

EPA's cost tool: http://www.epa.gov/airmarkt/arp/nox/controltech.html

V. Any uncertainty associated with the option

Uncertainties in FCPP's ability to meet the BART presumptive limit for SO_2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups None.

Citations:

[1] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=factstrends.top_bypollutant

[2] Although EPA limits annual average SO_2 emissions to 12.0% of the SO_2 produced by the plant's coal-burning equipment, its method of calculating the amount of SO_2 produced is not consistent with EPA's "Compilation of Air Pollutant Emission Factors," (AP-42) which assumes that 12.5% of the sulfur in sub-bituminous coal (as burned at FCPP) is never converted to SO_2 but is retained in the ash collected in the boiler. When this sulfur retention is taken into consideration, the EPA proposal represents 86% control of potential SO_2 emissions.

[3] BHP, the supplier of coal to FCPP, has projected coal quality to 2016 when its contract expires. This estimate is based upon 2016 coal with a heating value of 8,890 Btu/lb and a sulfur content of 0.85%. (document prepared by C. Nelson, BHP Navajo Coal Company on 27 February 2006 and submitted by Sithe Global as part of the Desert Rock permit application).

[4] All projections are based upon fuel quality estimates from the coal supplier and WRAP utilization growth projections.

[5] 70 F.R. 39134 (July 6, 2005).

[6] http://www.epa.gov/airmarkets/emissions/prelimarp/05q4/054_nm.txt

[7] 70 F.R. 39131, July 6, 2005.

[8] 70 F.R. 39135, July 6, 2005.

[9] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1.a. WRAP Total Extinction Trends

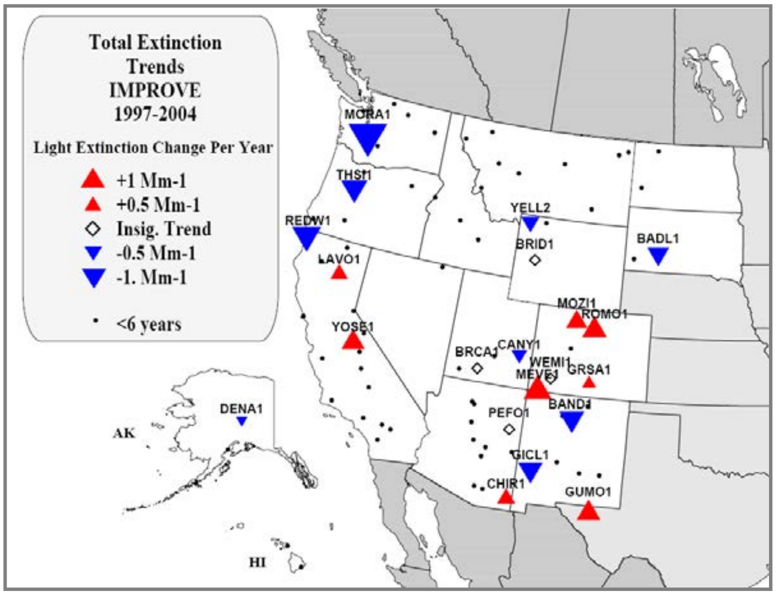


Figure 1.b. WRAP Sulfate Extinction Trends

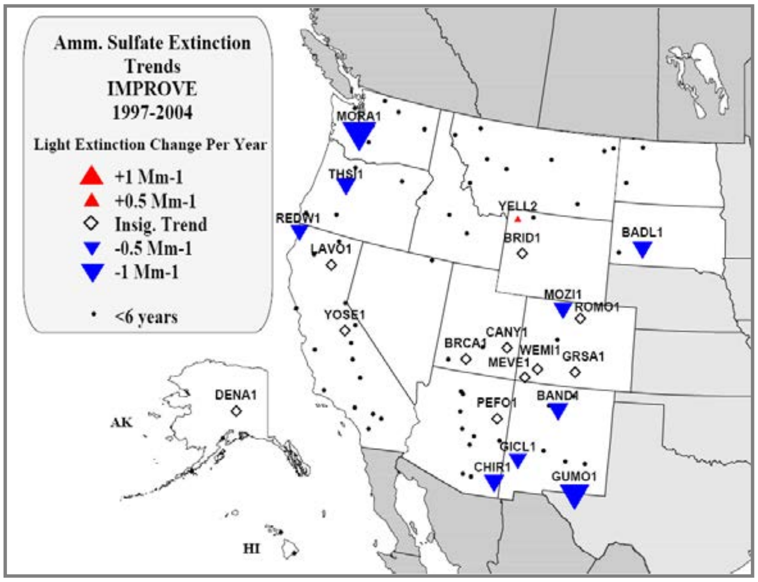


Figure 1.c. WRAP Nitrate Extinction Trends

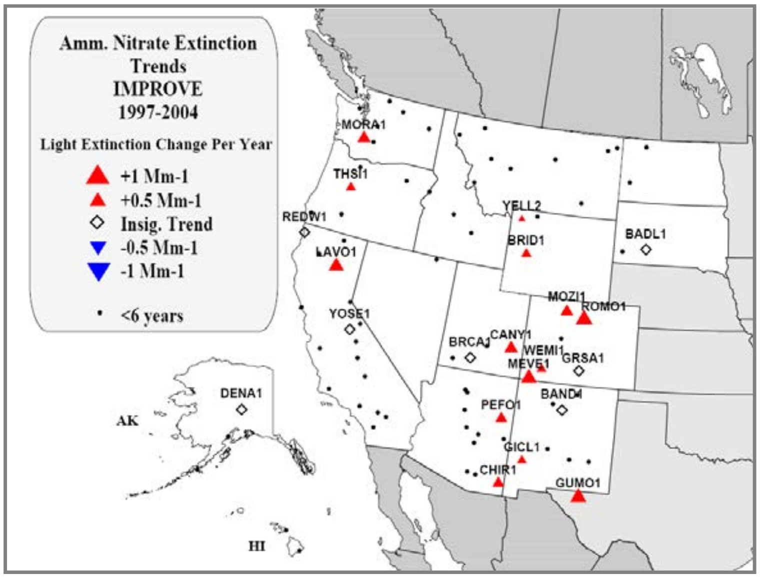


Figure 2. FCPP Emission Trends

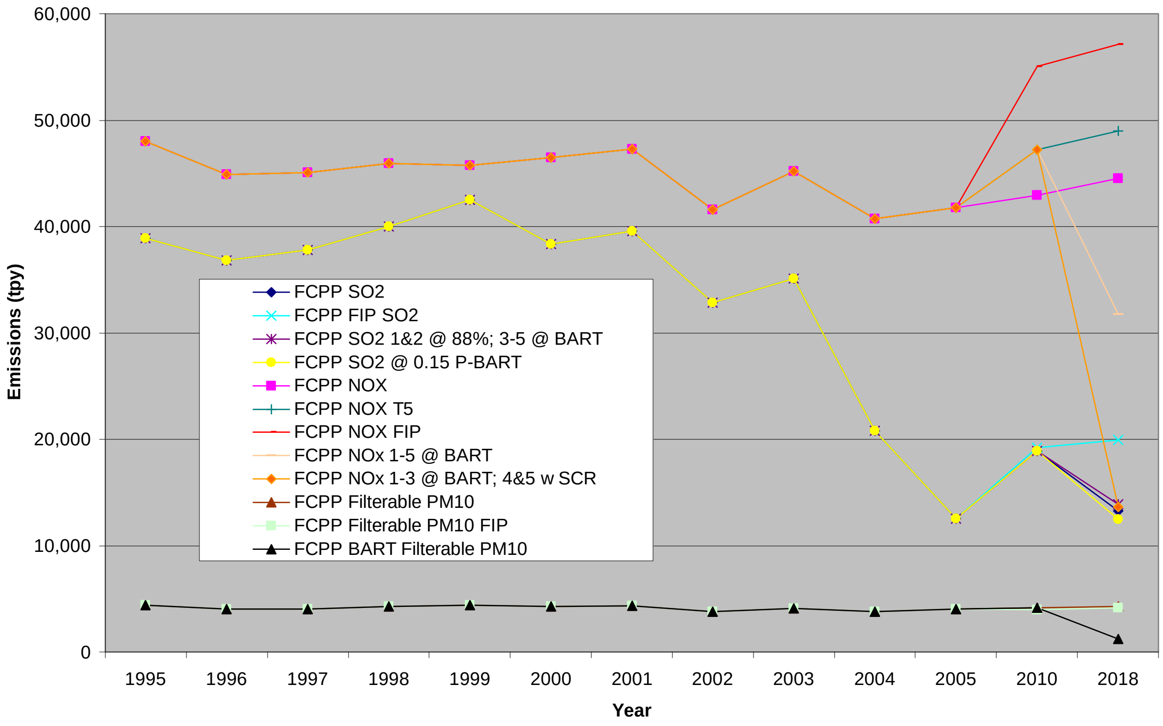


Figure 3. FCPP 2018 SO2 vs. Control Strategy

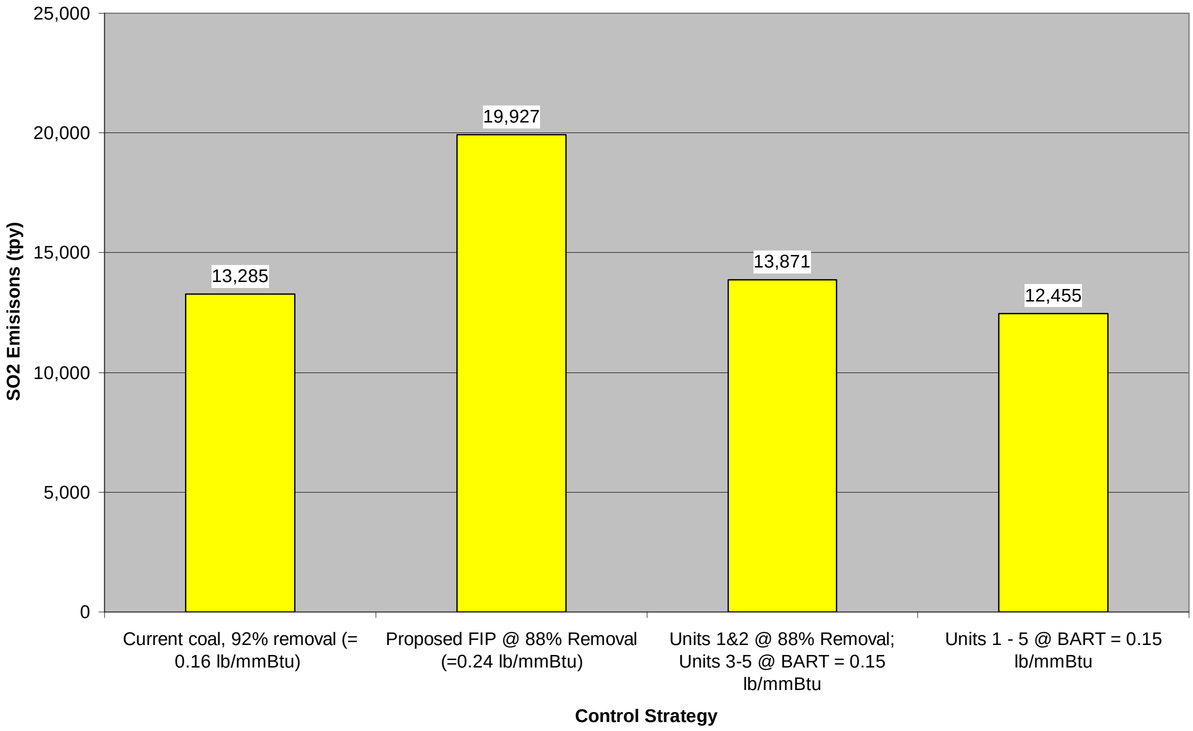
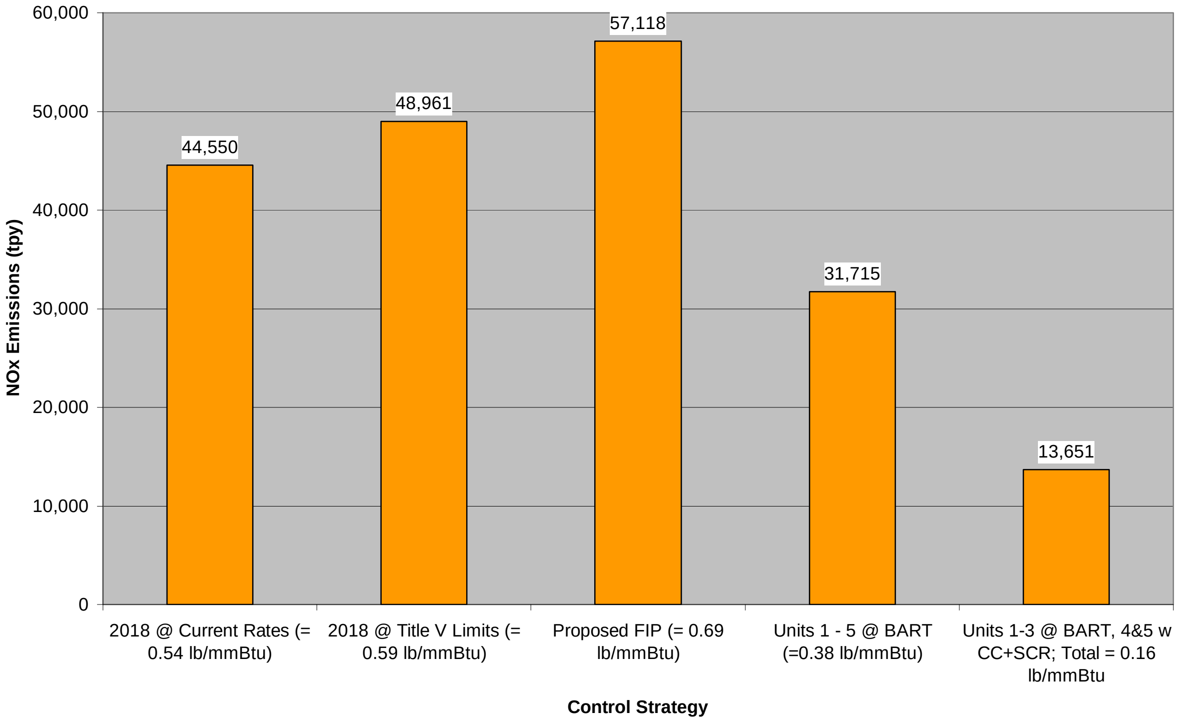


Figure 4. FCPP 2018 NOx Emissions vs Control Strategy



Mitigation Option: Control Technology Options for San Juan Generating Station

I. Description of the mitigation option

Summary of Option

Presumptive emission limits for NO_x should be applied to all units at San Juan Generating Station (SJGS).

Background: Best Available Retrofit Technology (BART)

SGJS consists of four pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu

Background: SJGS Emissions

In March of 2005, Public Service of New Mexico (PSNM) entered into a Consent Decree to reduce SO_2, NO_x, and PM_{10} emissions by 2010 at SGJS to the levels shown below:

- NO_x = 0.30 lb/mmBtu (30-day rolling average). The Consent Decree requires that San Juan minimize NOx emissions. The 0.30 lb/mmBtu limit will be evaluated after 1 year of operation and adjusted to a lower limit if possible.
- SO_2 = 90% annual average control,[1] not to exceed 0.250 lb/mmBtu for a seven-day block average.
- PM_{10} = 0.015 lb/mmBtu (filterable)

PSNM will replace all four existing Electrostatic Precipitators with Fabric Filters. San Juan currently meets the 0.015 lb/mmBtu limit with the existing Electrostatic Precipitators. The fabric filters (baghouses) will be installed primarily to reduce opacity spikes during upset conditions and to allow the addition of activated carbon for mercury control.

PSNM will have to meet the 90% SO_2 control requirement regardless of the coal quality. Current coal quality averages about 1.4 lb SO_2/mmBtu (uncontrolled). Therefore, ninety percent control would result in an annual average emission rate of 0.14 lb/mmBtu, and would likely satisfy the presumptive BART requirement.

Presumptive BART for NO_x at SJGS

The Consent Decree (CD) level for NO_x is 0.30 lb/mmBtu; the BART presumptive level for NOx is 0.23 lb NO_x/mmBtu. The BART presumptive level is lower than that in the CD, and therefore will result in lower emissions. Figure 1 depicts the historical trends of SO_2 and NO_x at SJGS, as well as future trends out to 2018 based upon available information on coal quality[2] and capacity utilization.[3] Emission increases after 2010 are due to increased utilization. The decreased NO_x emissions are based on the assumption that SJGS Units 1-4 will meet the presumptive BART limit for NO_x by 2018.

The presumptive BART level of 0.23 lbs/mmBtu was developed based on Powder River Basin (PRB) Coal. Although both the PRB and the San Juan Basin coals are considered sub bituminous, San Juan coal has properties of bituminous coal which has a higher presumptive BART level.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 43 km away from SJGS. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is the State of New Mexico.

III. Feasibility of the option

The Environmental Protection Agency's suggested presumptive BART limits "reflect highly cost-effective technologies."[4] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet these NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[5]

The most accurate cost estimate for SJGS to meet the BART limit for NO_x is likely to be from EPA's Cost Tool model, which estimates costs for specific units at specific emission rates.[6] That model predicts that the presumptive BART limits for NO_x could be met at costs of $355 - $501 per ton.

San Juan is currently in the process of doing a BART Analysis. It will be submitted to the NMED in June 2007.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11 State EGU Analysis" projections.
EPA's Cost Tool Model: http://www.epa.gov/airmarkt/arp/nox/controltech.html

V. Any uncertainty associated with the option (Low, Medium, High)

Uncertainties in SJGS's ability to meet the BART presumptive limit for SO2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None.

Citations:

[1] Based upon scrubber inlet and outlet SO_2 concentrations, as measured by Continuous Emission Monitors.

[2] Document prepared by C. Nelson, BHP Navajo Coal Company on Feb. 27, 2006 and submitted by Sithe Global as part of the Desert Rock permit application.

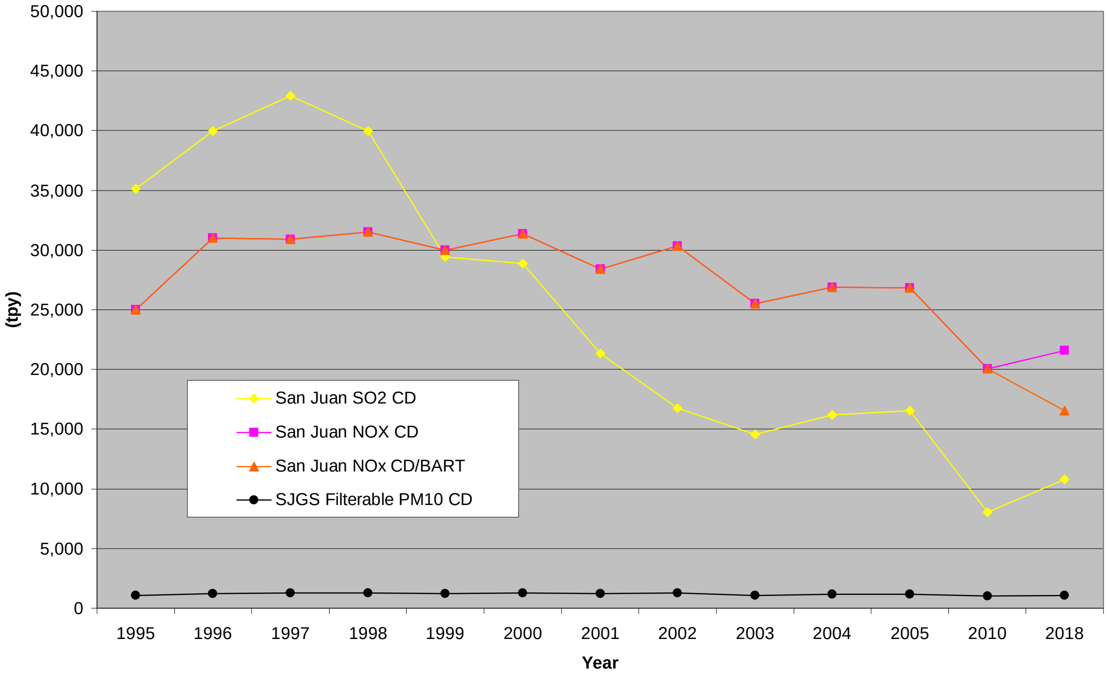
[3] Western Regional Air Partnership, 11 State EGU Analysis spreadsheet

[4] 70 F.R. 39131, July 6, 2005.

[5] 70 F.R. 39135, July 6, 2005.

[6] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1. San Juan SO2 & NOx



EXISTING: OPTIMIZATION

Mitigation Option: Energy Efficiency Improvements

I. Description of the mitigation option

Upgrades or major repairs to existing power plants are potentially subject to the New Source Review process. This includes projects that are undertaken to improve the efficiency of the plants (i.e., produce more power while burning less or the same amount of fuel.) This process has been so difficult and cumbersome that these projects are often not cost-effective to pursue. The regulatory agencies should work closely with the utilities to simplify the process, remove barriers and to encourage these efficiency improvements.

II. Description of how to implement

A. Mandatory or voluntary:

B. Indicate the most appropriate agency(ies) to implement

Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Air Quality Bureau

III. Feasibility of the option

A. Technical:
B. Environmental:
C. Economic:

IV. Background data and assumptions used:

V. Any uncertainty associated with the option (Low, Medium, High):

Medium

VI. Level of agreement within the work group for this mitigation option.

TBD

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Enhanced SO_2 Scrubbing

I. Description of the mitigation option

Enhanced SO_2 scrubbing on existing power plants in the Four Corners area has resulted in significant SO_2 reductions. This mitigation option suggests further efforts to develop and optimize SO_2 scrubbing at San Juan Generating Station and Four Corners Power Plant.

Background:
Wet Flue-Gas Desulfurization System:
Wet scrubbing, or wet flue gas desulfurization (FGD), is the most frequently used technology for post-combustion control of SO_2 emissions. It is commonly based on low-cost lime-limestone in the form of aqueous slurry. Lime is calcium oxide, CaO; Limestone is $CaCO_3$. The slurry brought into contact with the flue-gas absorbs the SO_2 in it. $CaSO_4$-$2H_2O$, Gypsum, is formed as a byproduct (1).

Gas flow per unit cross sectional area, which determines scrubber diameter, must be low enough to minimize entrainment. Mass transfer characteristics of the system determine absorber height. These vessels and the accompanying equipment used for slurry recycle, gypsum dewatering, and product conveyance tend to be quite large. Some variations of this technology produce high quality gypsum for sale. Less pure waste product may be sold for use in cement production. If neither of these options is practiced, the scrubber waste must be disposed of in a sludge pond or similar facility (2).

The wet scrubber has the advantage of high SO_2 removal efficiencies, good reliability, and low flue gas energy requirements (1).

What is being done:
San Juan Generating Station has initiated an Environmental Improvement program under its consent decree that includes enhanced SO_2 scrubbing. Projections show that optimization of SO_2 scrubbing will result in a reduction of SO_2 from the current emission rate of 16,569.5 tons/yr to an emissions rate of 8,900 tons/yr by the year 2010 (3, 4, 5). This would translate as an increase in SO_2 removal efficiency from 81% to 90% as required by the consent decree.

The Consent Decree that San Juan has entered into will require a minimum of 90% removal of SO2.

Four Corners Power Plant has also made significant improvements in SO_2 emissions control efficiency. APS, in partnership with the Navajo Nation, several environmental groups and federal agencies, conducted a test program to determine if the efficiency of the existing scrubbers at Four Corners Power Plant could be improved from the recent historical level of 72% SO_2 removal to 85%. The test program, which was completed in spring of 2005, was successful and the plant was able to achieve a plant-wide annual SO_2 removal of 88%. In fact, data indicates that a 92% removal, or 0.16 lbs/mmBtu SO2 limit was achieved. Some parties involved in the test program have agreed that a new rule should propose to require 88% removal efficiency for the Four Corners Power Plant (6). Parties are also interested, however, in a mass emissions limit as opposed to removal rate to protect against air quality degradation from higher sulfur coal.

The way “removal” is used here is based on including the amount of sulfur retained in the ash. For FCPP, this amounts to about 2% “bump-up” of the control efficiency. So, 88% removal is the equivalent of 86% control. By contrast, both the NM regulations and the SJGS consent decree require that the control efficiency across the scrubber be measured by CEMs before and after the scrubber.

72% SO_2 removal resulted in approximately 22,450 Tons/yr SO_2 emissions. The new emissions control removal efficiency of 88% translated to 12,500 Tons/yr SO2 emissions in 2005.

Further advances in SO_2 scrubber optimization should be explored and implemented as they become available. It may be possible to achieve over 90% SO_2 removal efficiencies with enhanced SO_2 scrubbing on existing power plants in the 4C area

During 2005, FCPP demonstrated that it can achieve better than 90% control of SO_2.

Benefits: SO_2 removal increase. Possible co-benefits are increased particulate removal, and also mercury removal.
Tradeoffs:
Burdens: Cost to existing power plants including: optimization controls or additional retrofit technologies.

II. Description of how to implement

A. Mandatory or voluntary
Voluntary emissions reductions that are above and beyond new standards

Differing Opinion: A FCPP FIP that reflects the capabilities of the control equipment and coal supply

B. Indicate the most appropriate agency(ies) to implement
New Mexico Air Quality Bureau
EPA Region 9 and Navajo Nation EPA

III. Feasibility of the option

A. Technical: technology is available and feasible.
B. Environmental: Optimized SO2 scrubbing could result in SO_2 control efficiency above 90%.
C. Economic: Improving existing emissions control process through optimization is often less expensive than retrofitting plant with entirely new emissions control equipment.

IV. Background data and assumptions used:

1. El-Wakil, M.M. Power Plant Technology; McGraw-Hill, New York: 2002.
2. Clean Coal Technology Topical Report #13, May 1999, DOE, "Technologies for the combined Control of Sulfur Dioxides and Nitrogen Oxides from Coal-fired Boilers"
3. Current estimated SO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
4. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"
5. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
6. Final rule for Four Corners Power Plant:
ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 49, [EPA-R09-OAR-2006-0184; FRL-], Source-Specific Federal Implementation Plan for Four Corners Power Plant; Navajo Nation

V. Any uncertainty associated with the option

Medium – SO_2 scrubbing control efficiencies have increased recently. Optimization of SO_2 scrubbing systems have limitations.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

EXISTING: ADVANCED NO_x CONTROL TECHNOLOGIES

Mitigation Option: Selective Catalytic Reduction (SCR) NO_x Control Retrofit

I. Description of the mitigation option,
To reduce NOx emissions from the existing power plants in the Four Corners area, a Selective Catalytic Reduction system could be retrofitted to San Juan Generating Station and Four Corners Power Plant.

Selective Catalytic Reduction, SCR, uses ammonia or urea along with catalysts in a post-combustion vessel to transform NO_x into nitrogen and water. It can achieve the 0.15-pound-per-million Btu standard (1).

Some eastern EGUs retrofitted with SCR have achieved 0.05 lb/mmBtu. Based on recent permit applications and boilers in the east that have retrofitted with SCR, this technology can typically achieve a 90 percent reduction in NO_x emissions.

Ammonia is used as the reducing agent. It is injected into the flue gas stream and then passes over a catalyst. The ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water.

The main Selective Catalytic Reduction reaction is $4NH_3 + 4NO + O_2 \rightarrow 4\ N_2 + 6H_20$ (2)

Supplemental description of Selective Catalytic Reduction available from US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)

This report further discusses technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system (3).

And the SCR system
The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system (3).

Based on heat input and emissions data from the Acid Rain Program:
Currently NO_x emissions from San Juan Generating Station are on the order of 0.42 lbs/mmBtu or 26,800 Tons/yr.
Currently NOx emissions from the Four Corners Power Plant are approximately 0.57 lbs/mmBtu or 40,700 Tons/yr (4). Note: FCPP is the largest NOx-emitting EGU is the US.

The proposed Desert Rock Energy facility is planning to build their facility with Selective Catalytic Reduction technology to control NO_x emissions. They expect 85-90% control of NOx. The permit allowed NOx emissions will be 0.060 lbs/mmBtu fuel input (2).

Retrofitting a Selective Catalytic Reduction to existing power plants would be much more difficult than installing equipment with the construction of the plant; however, it is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50%.

Differing Opinion: Applying SCR to existing plants may be more difficult than new installation; it is not a given. SCR has been successfully applied in the East in response to the CAIR rule. Retrofits at eastern utilities subject to the NOx SIP Call and CAIR typically set a 90% reduction goal. The vintage EPA Cost Tool database assumes 70% control by SCR, and SCR has improved dramatically since then.

Benefits: It is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50% - 90%+. SCR may have some co-benefit reductions of Mercury emissions.

Tradeoffs:
Ammonia that is not reacted will "slip" through into exhaust. Ammonium salts could also form thus increasing loading to the particulate collection stage as PM10 (and PM2.5) (2). This is less likely with lower sulfur coal.
SCR tends to increase the reaction of SO_2 to SO_3 and increases the formation of acid mists. This could require additional treatment of the flue gas. This is less likely with lower sulfur coal.

Any analysis should compare the cost of SCR to the costs of combustion controls.

Application of EPA's Cost Tool model for the Four Corners Power Plant, Units 4 & 5 predicts that NO_x could be reduced by 70 percent to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed. EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

Burdens: Retrofit costs to existing power plants. Installation may be cost prohibitive for some existing plants because of the physical layout of the plant. Safety issue with handling of ammonia for use as reducing agent

II. Description of how to implement

A. Mandatory or voluntary
Retrofit program could be mandatory or voluntary
SCR application could be considered in the context of BART.

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Bureaus, Federal EPA, Industry

III. Feasibility of the option

A. Technical – commercially available

B. Environmental – high reduction efficiencies demonstrated 85-90+%.
Sulfur content of the coal is an important factor in use of SCR. The low-sulfur coals burned in the 4 Corners area should be more compatible with SCR. SCR is being widely applied to a variety of bituminous and sub-bitumninous coals, especially in the East. Requiring catalyst replacement is an economic issue.

The SCR process is subject to catalyst deactivation over time (2).

C. Economic – Retrofit costs. Additional maintenance costs

*Cumulative Effects Work Group – How would 50%-90% emissions reductions from the two existing power plants affect visibility and ozone?
*Monitoring Work Group – Would it be possible to measure ammonia slip in the exhaust gases?

IV. Background data and assumptions used

1. US Department of Energy (DOE) Pollution Control Innovations Program
http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/index.html

2. Development of Nitric Oxide Catalysts for the Fast SCR Reaction, Matt Crocker, Center for Applied Energy Research, University of Kentucky (2005)

3. US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)
*A good description of Selective Catalytic Reduction is available on pp.9-10 of the US EPA, Ambient Air Quality Impact Report, Best Available Control Technology discussion, for the Desert Rock Energy Facility.

4. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

5. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"

V. Any uncertainty associated with the option High.

Differing Opinion: The success of SCR in reducing NO_x emissions is a proven technology

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Oil & Gas industry may also look at SCR as a method to reduce natural gas compressor NO_x emissions

Mitigation Option: BOC LoTOx^{TM} System for the Control of NOx Emissions

I. Description of Mitigation Option

Belco BOC LoTox is an oxidation technology for flue gas NOx control. It was developed in recent years and has become commercially successful and economically viable as an alternative to ammonia and urea based technologies. Older commercial technologies such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which reduce NOx to nitrogen using ammonia or urea as an active chemical, are limited in their use for high particulate and sulfur containing NOx streams such as from coal-fired combustors, or are unable to achieve sufficient NOx removal to meet new NOx regulation levels. In contrast, oxidation technologies convert lower nitrogen oxides such as nitric oxide (NO) and nitrogen dioxide (NO2) to higher nitrogen oxides such as nitrogen sesquioxide (N2O3) and nitrogen pentoxide (N2O5). These higher nitrogen oxides are highly water soluble and are efficiently scrubbed out with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. NOx removal in excess of 90% has been achieved using oxidation technology on NOx sources with high sulfur content, acid gases, high particulates and processes with highly variable load conditions.

The BOC LoTOx^{TM} System is based on the patented Low Temperature Oxidation (LTO) Process for Removal of NOx Emissions, exclusively licensed to BOC Gases by Cannon Technology. This technology has met the stringent cost and performance guidelines established by the South Coast Air Quality Management District in Diamond Bar, CA and has set new lower limits for Best Available Control Technology (BACT) and Lowest Achievable Emissions Reduction (LAER). The LoTOx^{TM} System for NOx Control uses oxygen to produce ozone as the primary treatment chemical using an ozone generator. The oxidation of NOx using ozone is a naturally occurring process in the atmosphere. The absorption of higher nitrogen oxide by water to form nitric acid is also a naturally occurring process in the atmosphere, resulting in “acid rain”. The LoTOx^{TM} System reproduces these naturally occurring processes under controlled conditions within an enclosed system. This treatment method produces the treatment chemical, ozone, on demand from gaseous oxygen in the exact amount required for oxidation of the NOx.

A demonstration was conducted at Southern Research Institute’s (SRI) Combustion Research Facility, Birmingham, AL using a mobile demonstration trailer. The test was the first in a series of tests planned to demonstrate the effectiveness of ozone for oxidation and removal of NOx emissions from SRI’s coal-fired combustor. The results from the tests demonstrated that the LoTOx^{TM} System is highly effective for removal of NOx emissions from as high as 350 ppmv NOx to below 50 ppmv NOx levels without significant residual ozone in the exhaust stream. The LoTOx^{TM} System is very selective for NOx removal, oxidizing only the NOx and therefore efficiently using the treatment chemical, ozone, without causing any significant SOx oxidation and without affecting the performance of the downstream SOx scrubber. Furthermore the ozone/NOx ratios required to produce desired NOx oxidation are less than the predicted stoichiometric amounts. Various types of coals and fuel types will be used in the combustor. The information gathered will be used for the design of commercial LoTOx^{TM} Systems for effective and efficient NOx removal at utility power plants and other large-scale NOx sources. [1]

Chemistry

The LoTOx process is based on the excellent solubility of higher order nitrogen oxides. Typical combustion processes produce NOx streams that are approximately 95% NO and 5% NO2. Both NO and NO2 are relatively insoluble in aqueous streams, therefore, wet scrubbers will only remove a few percent of NOx from the flue gas stream. Species Solubility at 25°C and 1 atm
NO 0.063 g/l, NO2 1.260 g/l
The LoTOx process uses ozone to oxidize NO and NO2 to N2O5 ,which is highly soluble, and by wet scrubbing N2O5 is easily and quickly converted to HNO3, based on the following reactions:
$NO + O3 \rightarrow NO2 + O2$
$2NO2 + O3 \rightarrow N2O5 + O2$

$N_2O_5 + H_2O \rightarrow 2HNO_3$
Both N2O5 and HNO3 are extremely soluble in water. N2O5 reacts instantaneously with water forming HNO3. Since HNO3 is so highly soluble (approaching infinity) it is difficult to measure, and therefore reliable solubility data is not available in published literature. However, HNO3 mixes with water in all proportions and therefore the N2O5 to HNO3 reaction is irreversible in the presence of water. [2]

Benefits: Low Temperature, No chemical slip
Tradeoffs:

Burdens:
Ozone unused in the treatment process produces no health hazards to plant workers nor to the environment. The ozone is injected into flue gas stream where it reacts with relatively insoluble NO and NO2 to form N2O3 and N2O5, which are highly water soluble, and are easily and efficiently removed and neutralized in a wet scrubbing system. [1]

II. Description of how to implement

A. Mandatory or voluntary
LoTOx could be the answer to achieve required limits under regional haze rule. This control technology could be an option to meet mandatory emissions limits

B. Indicate the most appropriate agency(ies) to implement
4 Corners Power Plants would implement new technology as an integrated component of emissions control system

III. Feasibility of the option

A. Technical: Low temperature reaction is good. Ozone generation and other LoTOx system components are well understood technologies used in other applications.
B. Environmental: Pilot scale demonstrations showed 90% removal, very high reduction efficiencies
C. Economic: Retrofit technologies can be expensive on existing power plants.

This technology has only been tested on pilot plants and there are no full scale installations. The technology should therefore, at this point, be considered not technically feasible.

IV. Background data and assumptions used

1. DEMONSTRATION AND FEASIBILITY OF BOC LoTOx^{TM} SYSTEM FOR NOx CONTROL ON FLUE GAS FROM COAL-FIRED COMBUSTOR abstract, presented at 2000 Conference on SCR & SNCR for NOx Control/BOC, http://www.netl.doe.gov/publications/proceedings/00/scr00/ANDERSON.PDF
2. CARB Innovative Clean Air Technology, “Low Temperature Oxidation System Demonstration,” BOC paper 1999, http://arbis.arb.ca.gov/research/apr/past/icat99-2.pdf
3. DuPont BELCO LoTOx Technology homepage http://www.belcotech.com/products/nox.html

V. Any uncertainty associated with the option

Medium, any retrofit technology has a degree of uncertainty. It can be difficult and expensive to retrofit emissions control technology that the plant was not originally designed for.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: OTHER RETROFIT TECHNOLOGIES

Mitigation Option: Baghouse Particulate Control Retrofit

I. Description of the mitigation option

Installation of baghouses at existing power plants in the Four Corners area could reduce particulate emissions by approximately 25% or more. Baghouses, or fabric filters, as they are often called, collect fly ash and other particulate matter from the coal combustion process like large vacuum cleaners. Typically a baghouse removes more than 99.8 % of the fly ash.

The original design for the two major power plants in the 4 Corners area was for electrostatic precipitators (ESPs). The ESPs on San Juan Generating Station remove approximately 99.7 % of the particulate matter from the exhaust stream. This exceeds current state and federal emissions requirements (0.1 lbs/mmBtu and 0.05 lbs/mmBtu).

The San Juan generating station is currently undergoing a series of environmental improvements between 2007 and 2009 including designing for a 0.015 lbs/mmBtu particulate limit. PNM will install fabric filters (baghouses) for all four SJGS units collect particulate emissions. The ESPs at San Juan will remain in place but will be de-energized. It is believed that a portion of the ash will continue to be removed in the ESPs (because of gravity separation) but they will not be considered a control device. One of the reasons to install the baghouses was because of PNM's commitment for Activated Carbon Injection for the removal of mercury. An ESP would not have been efficient in the collection of the activated carbon. An additional benefit of the baghouse is the reduction of opacity spikes that are caused by an increase in unburned carbon in the flyash. This unburned carbon is caused by combustion problems associated with the operation of the low-NOx burners and is not efficiently collected by an ESP. Also, we will not know until the Baghouses are installed and operational, but we do not anticipate that the actual particulate emissions will be significantly less than the current emissions. However, the permit requirement will be reduced from 0.05 lbs/mmBtu to 0.015 lbs/mmBtu.

Since all units at San Juan and Units 4 & 5 at Four Corners currently have or will have baghouses in the near future, this option will only apply to Units 1,2 & 3 at Four Corners.

Benefits: Current reported levels of particulate emissions at major power plants in the 4Corners area include: San Juan Generating Station emits approximately 673 Tons/yr, approximately .011 lbs/mmBtu; 4 Corners Power Plant emits approximately 1,187 Tons/yr, approximately .017 lbs/mmBtu (see 4CAQTF_PowerPlant_WorkGroup_ FacilityDataTableV10). Baghouse installation may result in improved particulate removal efficiencies. If baghouses could reduce emissions to .010 lbs/mmBtu, this option could lead to over 500 tons per year reduction of particulates collectively from the two largest coal fired power plants in the region.

Differing Opinion: The benefits (500 ton reduction of particulates) may be over estimated because San Juan and Four Corners Unit 4 & 5 will have baghouses and will perform at or close to the 0.01 lbs/mmBtu. The only units that would see a reduction would be Four Corners Units 1,2 & 3.

Burdens: Cost of baghouse installation on power plants

II. Description of how to implement

A. Mandatory or voluntary
Voluntary or consent decree

B. Indicate the most appropriate agency(ies) to implement
Power Plants would install

III. Feasibility of the option

A. Technical: Technology is available commercially

B. Environmental: Feasible

C. Economic: Expensive to install new technology

IV. Background data and assumptions used

1. San Juan Generating Station (SJGS) Emissions Control Current and Future, presentation for 4CAQTF, May 2006 ,http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf

2. 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10

3. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

4. San Juan Environmental Improvement Upgrades Fact Sheet,
http://www.pnm.com/news/docs/2005/0310_sj_facts.htm

V. Any uncertainty associated with the option

Medium.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other Task Force work groups

None.

Mitigation Option: Mercury Control Retrofit

I. Description of the mitigation option
Existing power plants in the Four Corners area should evaluate the installation of mercury removal technology to reduce mercury emissions. According to EPA's 2005 Toxic Release Inventory report the San Juan Generating Station released 770 lbs and Four corners Power Plant released 625 lbs of mercury into the air. Activated carbon injection technology is the most likely control technology at this time. This technology has been demonstrated in several pilot studies.

The Clean Air Mercury Rule (CAMR) will require the reduction of mercury emissions from power plant beginning in 2010 with further reductions in 2018. This rule will also require the installation of mercury Continuous Emissions Monitoring systems by January 1, 2009.

San Juan Generating Station will have mercury control (activated carbon injection) on all four units by 2010 and Mercury CEMs on 2 units by 2008 and all 4 units by 2009.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory and/or Voluntary

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Environment Department

III. Feasibility of the option
A. Technical: The injection of activated carbon into the flue gas stream has been demonstrated in pilot studies to remove mercury. However, there have not been any long-term applications of this technology. Also the effectiveness of this technology has not been demonstrated on the type of coal in the San Juan Basin so the actual removal efficiency of the technology is unknown. Nevertheless, many new coal-fired power plant projects are proposing installation of activated carbon injection.

B. Environmental: Mercury emissions will be reduced, however, the addition of activated carbon to the fly ash will make the ash unsuitable for sale to the cement/concrete industry and will increase the amount of fly ash that will have to be disposed.

C. Economic: The cost of additional equipment for ACI injection is relatively small, however, the annual operating and maintenance cost can be significant because of the cost of the activated carbon. Also there currently is a limited supply of activated carbon. The increase cost for ash disposal could be significant. Also, ACI injection requires a bag house or fabric filter for particulate control. This cost would be significant if this technology would have to be retrofitted to existing units.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: STANDARDS

Mitigation Option: Harmonization of Standards

I. Description of the mitigation option,

This option would require existing power plants to meet the most stringent standard of any governmental agency in the region, i.e., the strictest state, federal, or tribal standard. At present facilities are subject to varying standards depending on where they are located, even though emissions affect the entire area and beyond.

This option is limited to existing power plants on the basis that new power plants are held to Best Available Current Technology (BACT) limitations on controlled emissions, which are usually much lower than current state or federal air standards.

One of problems in the Four Corners area is the aging fleet of large power plants. These older power plants have significantly higher emissions than potential new sources. The two largest generating stations in the Four Corners Region, Four Corners Power Plant (FCPP) and the San Juan Generating Station (SJGS), are regulated by different agencies even though they are within 30 miles of each other. San Juan Generating Station is being held to more stringent regulations by the New Mexico Air Quality Bureau regulations.

The burden of this requirement to adopt more stringent regulations would fall on the owners of the facilities and might also lead to the eventual retirement of some older Four Corner area power plants. However, the long-term effect of this rule, especially if applied to other multi-state regions over time, might lead to standardized regulations, also a benefit, if the new standards converged on the most stringent requirement.

II. Description of how to implement

This rule should be mandatory and phased in over a designated period of time.

A valuable lesson is to be learned from the Four Corners Power Plant jurisdiction quandary. The Navajo Tribe ruled that the State of NM cannot regulate and enforce FCPP emissions. Very recently, a lawsuit was filed against the Federal EPA regarding FCPP emissions. This lawsuit may have expedited the current series of action by the Federal EPA such as public sessions, the FIP, etc. The FCPP is on tribal land, but the air emissions affect the entire Four Corners area. Somehow, a regulatory agency responsible for governing and enforcing emissions of present and future power plants and oil and gas facilities should be agreed upon by all entities.

The area's ozone problem is an example of why it is important to have one regulatory agency. The Four Corners area has unusually high volumes of ground level ozone. The Four Corners Ozone Task Force (FCOTF) has been working for the past several years on ozone mitigation options. The FCOTF is working closely with EPA Region 6. Recently EPA Region 9 officials came to the area to talk about the proposed Desert Rock coal fired power plant. This area's ozone problems were not addressed by EPA Region 9 in the Desert Rock Proposed PSD Permit. In order to avoid costly environmental oversights and/or confusion, only one EPA Region should be designated as the Federal Agency to regulate and enforce in an area such as the Four Corners.

Differing Opinion: Implementing this option could initially be voluntary, as it would ultimately require changes to the Clean Air Act and/or Code of Federal Regulations to address tribal authority over air programs, and the role of the Federal Implementation Plan.

III. Feasibility of the Option

Technical issues: none, technology currently exists to meet the most stringent existing requirement

Environmental issues: Benefits of stricter standards are intuitive. The following are examples of significant disparities in state and federal limits:

For example, the current State permit limit for NOx emissions from San Juan Generating Station is 0.46 lbs/mmBtu. The federal limits for NOx at Four Corners Power Plant are 0.65 – 0.85 lbs/mmBtu. San Juan Generating Station NOx emissions rate is approx. 0.4 lbs/mmBtu or 26,800 Tons/yr. Four Corners Power Plant, under the federal regulation, emits approx 0.6 lbs/mmBtu or approx 41,700 tons/yr

The state limit for SO_2 emissions from San Juan Generating Station is 0.65 lbs/mmBtu. The federal limit applied to Four Corners Power Plant is 1.2 lbs/mmBtu. The state permit limit for PM emissions from San Juan Generating Station is 0.05 lbs/mmBtu. The Federal PM standard is 0.1 lbs/mmBtu.

Economic: Implementation of resulting standards could be expensive. Experience of the political unit currently having the strictest standard could provide some data on the cost. In any case, the standard, even though not industry-wide, would be applicable area-wide and therefore more fair to competing power generators

Political issues: resistance would be great, just as it is now to tightening of standards. Effective implementation of this idea might require creation of a Four Corners regional authority or special district, which might require enabling legislation: the difficulty of accomplishing this is unknown.

IV. Background data and assumptions

The Federal/State PSD rules are applied industry wide for new power plants and existing power plants with major modifications in NAAQS attainment areas. Existing power plants in different jurisdictions continue to be regulated by different standards even though they are in the same air basin. This option would be a step in harmonizing standards. It is clear that the two plants we have heard from could meet tighter standards, especially when applied industry-wide; but since they are not required to do so, they cannot get their owners to support meeting them. It is intuitive that if any installation in the Four Corners region using San Juan Basin coal can meet the tightest standard, they all can over a reasonable period of time.

Green House Gases Such as Carbon Dioxide –
It is becoming more and more apparent that Global Warming or Climate Changes is a world wide problem. Reductions in carbon dioxide emissions, one of the green house gases, should be addressed in the Mitigation Options for all existing and future coal fired power plants in the San Juan Basin. The carbon dioxide issue will have to be dealt with sooner or later and the sooner, the better.

New Mexico Environmental Regulations for Air Quality may be found at:
http://www.nmenv.state.nm.us/aqb/regs/index.html

V. Any uncertainty associated with the option

There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

EXISTING: MISCELLANEOUS

Mitigation Option: Emission Fund

I. Description of the mitigation option

This option would establish an emissions fund for emitters of one or more air pollutants of concern, such as nitrogen oxides. Sources emitting more than a specified amount annually would pay by the ton emitted into a fund that would then be used for environmental improvement projects. There should be no maximum number of tons over which fees wouldn't be paid.

The fund should be used for environmentally beneficial projects, to be decided by the administering body (see below). One option is to have a grant system whereby applications are made to the fund by anyone—regulated community, environmental community, public, academia, etc—and the administering body would have set criteria against which they evaluated each request. Another option is to specify the allowable uses of the fund, such as for the development or investment in innovative technologies.

Benefits: Ideally, emitters required to pay per ton emitted would have an incentive to emit less. To make this incentive effective, the fee per ton would need to be relatively high. A thorough search of similar programs and any evaluations of those programs should be done to determine what fee level would provide an effective incentive. Monetary incentives could result in emission reductions at significantly lower costs than "command and control" regulation. Emission fees also work to "internalize the externalities" involved in air emissions and environmental degradation by recognizing and attempting to account for the social costs of the operations of the emitters.

Burdens: the primary burden would be on the emitter, to pay into the fund based on annual emissions. There would be some administrative burden, lessened by using existing reporting and oversight frameworks to implement the program.

II. Description of how to implement

A. Mandatory of voluntary: Payment into an emission fund would be mandatory for a defined size or class of sources

B. Most appropriate agency to implement: These programs have generally been administered by state agencies. Tribal air quality agencies could also develop and implement an emissions fund. An oversight committee or the air quality entity with regulatory authority would have authority to administer the fund. The committee or board should have members representing the regulated community, environmental community and general public.

The program could be phased in: fees per ton of emissions of specified pollutant(s) could gradually be increased over 5-10 years. The program could be based on existing permitting systems: fees would be based on the number of tons reported emitted, via existing reporting requirements within permits or any other existing framework for reporting.

III. Feasibility of the option

Emissions funds for air pollution are used in France, Japan and many states as well. There are no technical feasibility issues associated with this option.

IV. Background data and assumptions used

Stavins, R. (Ed.) (2000). *Economics of the Environment (4th Ed.)*. WW Norton: New York, New York.
New Hampshire Code of Administrative Rules, Chapter Env-A 3700: *NOx Emissions Reduction Fund for NOx-Emitting Generation Sources*.

Ohio EPA *Synthetic Minor Title V Facility Emission Fee Program*. http://www.epa.state.oh.us/dapc/synmin.html. (via statute--need cite).

Texas Administrative Code, Title 30, Part 1, Chapter 101, Subchapter A, Rule sec. 101.27: *Emissions Fees*

V. Uncertainty

VI. Level of agreement within workgroup

VII. Cross-over issues to other workgroups

The oil and gas industry could be subject to the emissions fund.

PROPOSED POWER PLANTS: DESERT ROCK ENERGY FACILITY

Mitigation Option: Desert Rock Energy Facility Stakeholder Funding to and Participation in Regional Air Quality Improvement Initiatives such as Four Corners Air Quality Task Force

I. Description of the mitigation option

Sithe Global and other stakeholders in Desert Rock Energy Facility will provide time and resource commitments to participate in inter-agency environmental initiatives to improve air quality in the Four Corners area.

Background:
Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (3). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

While the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area. See appendix 1.

Industry support would help to provide the resources necessary to ensure the air quality in the Four Corners, including our National Ambient Air Quality Standards (NAAQS) attainment, is maintained. There are substantial stakeholder interests in having air quality cleaner than simply meeting the NAAQS, for example, to improve visibility.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of a Voluntary Regional Air Quality Improvement Plan, CO2 emissions, and IGCC in relation to the proposed facility. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Environmental initiatives will be supported by industries that contribute to the air quality issues. Much needed financial support will be provided to regional environmental initiatives. Information resources will be provided to help in the environmental regulation planning process.

Tradeoffs: None

Burdens: Sithe Global and other stakeholders will provide time and resource commitment to participate in inter-agency environmental initiatives in the Four Corners area.

II. Description of how to implement

A. Mandatory or voluntary
Voluntary or mandatory

Differing Opinion: Mandatory: because of the fact that the Four Corners Area is already heavily polluted by several industrial sources such as the Four Corners Power Plant and the San Juan Generating Facility, over 19,000 oil and gas wells (over 12,500 new wells are planned in the next two decades), a fast growing population, more motor vehicles, etc.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Air Programs
Desert Rock Energy Project voluntary participation

Differing Opinion: According to an article in the December 11, 2006 "Farmington Daily Times" titled "Navajo Nation to Partially Own Desert Rock", "Representatives from the Dine Power Authority (DPA) say they will operate the proposed Desert Rock Power Plant with at least one degree of separation from the Navajo Nation Environmental Protection Agency (NNEPA) which will have oversight of the project." This should be a major concern. The Desert Rock Power Plant if built, must be closely monitored and enforcement must be very strict. There are concerns that a conflict of interest may exist. The Federal EPA should be the governing agency.

III. Feasibility of the option

Feasible.

IV. Background data and assumptions used

Literature cited
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(3) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

V. Any uncertainty associated with the option

Low.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

None.

Table 1. Estimated Maximum Annual Potential Emissions from Desert Rock Energy Facility [Source: AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)]

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Project Estimated Emissions
NOx	3,315	7.13	2.26	0.41	n/a	3,325
CO	5,526	2.55	0.17	0.031	n/a	5,529
VOC	166	0.17	0.11	0.019	n/a	166

SO2	3,315	3.61	0.068	0.012	n/a	3,319
PM[2]	553	1.02	0.083	0.015	16.1	570
PM10[3]	1,105	1.68	0.077	0.014	12.9	1,120
Lead	11.1	0.00064	0.00012	0.0000022	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	13.3
H2SO4	221	0.062	0.002	0.0004	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	0.057

[1] tpy -tons per year

[2] PM is defined as filterable particulate matter as measured by EPA Method 5.

[3] PM$_{10}$ is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM$_{10}$ as a surrogate for PM$_{2.5}$.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be used over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Area

I. Description of the mitigation option

The present proposed monitoring permit requirements for Desert Rock Energy Facility address only measurement of permit standards while there is another category of monitoring which could and should be done. This category would be data needed or useful for the evaluation of mitigation options in the present or the future.

PROPOSED ADDITIONAL MONITORING
a. PM2.5 continuous monitoring requirement.
The Four Corners region has several class 1 areas and a long term requirement by the EPA for improving visibility. PM2.5 is a critical element in this problem and future mitigation of it will require precise knowledge of the relative contributions from multiple and varied sources. This could come about by inclusion in the EPA permit conditions or by the company adding it to what they are doing to protect themselves from future finger pointing. Either way the data needs to be publicly available so those evaluating mitigation options have the use of it.

Total filterable PM CEMs have been certified by EPA. EPA contends that there is no currently certified method to continuously monitor PM_{10} or $PM_{2.5}$. However, there are some PM CEMs vendors that suggest CEMS can be modified to monitor a certain particulate size fraction.

b. Speciated Mercury (Hg) stack emission plus a plume contact measurement.
This region now has several lakes where restrictions of fishing exist because of Hg levels in the fish. The sources of Hg are multiple (geology, mining, oil & gas, agriculture, and power plants) to devise a proper mitigation plan the Hg species will need to be known so that sources can be identified and contribution determined. Models which predict Hg species in the environment from those found in the stack have shown problems. (Hg Speciation in Coal-fired Power Plant Plumes Observed at Three Surface Sites in the SE U.S.,Environ. Sci. Technol.2006, 40, 4563-4570:Modeling Hg in Power Plant Plumes, Environ. Sci. Technol,2006, 40,3848-3854) For this reason sampling at plume ground contact needs to be done to determine species for our environment and plant and coal types as the Hg enters the environment since we can not count on modeling to give correct Hg speciation. The stack sampling should be required under the permit plume surface contact samples however might be a cooperative venture between state or tribal personnel and the company. (State or Tribal personnel taking the sample and this sample then run by the company with the stack sample.)

c. VOC sampling in addition to that presently specified in the permit.
While the VOC's are nowhere near levels that would cause general health problems they are critical to the processes involved in the visibility problem which needs addressing. VOC's react in the plume after emission and change. A measurement of the VOC's after the initial reaction in the plume would be advantageous since it would give what is present to react to give the visibility problems. The VOC's present after this initial reaction is usually predicted by modeling however the literature indicates there are some problems with this approach measurements made at the plume ground contact could be a joint operation. State or Tribal personnel might collect a sample with the company running the sample with their stack sample.

II. Description of how to implement

A. Mandatory or voluntary
Desert Rock Energy Facility would be responsible for facility monitors

There are concerns that there are not enough monitors in place in the Four Corners Area and that the existing monitors are not placed in optimum locations. Several more monitors in logical locations must be installed in order to accurately measure emissions. The Federal, State, and Tribal EPA agencies should be responsible for collection and analyzing samples. The Four Corners Power Plant and the San Juan Generating Station are among the dirtiest coal fired power plants in the Nation. Desert Rock must be placed under strict scrutiny. The Four Corners Area is already close to ground level ozone levels of non-attainment. The area cannot afford further degradation of the air quality.

B. Indicate the most appropriate agency(ies) to implement
State or Tribal personnel might collect and analyze some samples

III. Feasibility of the option

A. Technical
B. Environmental
C. Economic

*Monitoring Work Group – assess the feasibility (technical, environmental, and economic) of conducting the proposed monitoring.
*Cumulative Effects Work Group – Will the proposed additional monitoring in this mitigation option be useful in assessing the Desert Rock Energy Facility point source contributions to the cumulative Four Corners area air quality?

IV. Background data and assumptions:

V. Any uncertainty associated with the option (Low, Medium, High)

Low

VI. Level of agreement within the work group for this mitigation option

TBD

VII. Cross-over issues to the other source groups

None

Mitigation Option: Coal Based Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, should be considered in the BACT analysis.

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

On July 7, 2006, the Environmental Protection Agency (EPA) released a technical report titled "The Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The Report provides information on the environmental impacts and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to conventional pulverized coal (PC) technologies.

"IGCC is a power generation process that uses a gasifier to transform coal (and other fuels) to a synthetic gas (syngas), consisting mainly of carbon monoxide and hydrogen. The high temperature and pressure process within an IGCC creates a controlled chemical reaction to produce the syngas, which is used to fuel a combined cycle power block to generate electricity. Combined-cycle power applications are one of the most efficient means of generating electricity because the exhaust gases from the syngas-fired turbine are used to create steam, using a heat recovery steam generator (HRSG), which is then used by a steam turbine to produce additional electricity (3)."

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, was not included in the BACT analysis for the Desert Rock Energy Facility (2).

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of IGCC. Please see the comment in its entirety in the appendix to the Power Plants section.

Benefits: For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM) and mercury (Hg), IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. IGCC also has multi-media benefits, as it uses less water than Pulverized Coal facilities. IGCC also produces a solid waste stream that can be a useful byproduct for producing roofing tiles and as filler for new roadbed construction. IGCC also has the potential to reduce solid waste by using as fuel a combination of coal and renewable biomass products (3).

IGCC is considered one of the most promising technologies to reduce the environmental impacts of generating electricity from coal. EPA has undertaken several initiatives to facilitate the development and deployment of this technology

IGCC thermal performance (efficiency and heat rate) is significantly better than current generation pulverized coal technologies in the US;

The Capture of CO2 emissions from IGCC plants would be cheaper and less energy intensive than in conventional coal plants (3, 6)

Tradeoffs:
Burdens: IGCC has 10 – 20 % higher capital costs than conventional PC plants [3]
When carbon capture becomes mandatory, that cost disadvantage will likely disappear.

II. Description of how to implement

A. Mandatory or voluntary
Mandatory to look at IGCC as a Best Available Control Technology option for future power plants in the Four Corners area

Permit levels could be set based upon IGCC performance. It would be up to the source how to meet those limits with whatever technology it chooses.

This could be a new legislative requirement at the State or Tribal level

B. Indicate the most appropriate agency(ies) to implement
Policy options for use of Integrated Gasification Combined Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), New Mexico Energy, Minerals, and Natural Resources Department (NMEMNRD).

*EPA could designate IGCC as a Best Available Control Technology.

Differing Opinion:
Assuming that coal gasification is an innovative fuel combustion technique for producing electricity from coal, EPA does not believe Congress intended for an "innovative fuel combustion technique" to be considered in the BACT review when application of such a technique would redesign a proposed source to the point that it becomes an alternative type of facility. In prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. Therefore, the question is whether IGCC results in a redefinition of the basic design of the source if the permittee is proposing to build a supercritical pulverized coal (SCPC) unit. EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source if a supercritical pulverized coal unit was the proposed design. Accordingly, consistent with our established BACT policy, we would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis. Instead, we believe that an IGCC facility is an alternative to an SCPC facility and therefore it is most appropriately considered under Section 165(a)(2) of the CAA rather than section 165(a)(4).

Four Corners state legislatures and/or Tribal Nations could legislate that IGCC be considered?

III. Feasibility of the option

A. Technical:
Development and implementation of IGCC technology is relatively new compared with the PC technology that has hundreds or thousands of units in operation globally. Currently in the US there are two gasification unit installations using coal to make electric power as the primary product. The two IGCC plants in commercial operation include the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana. Each has been in operation since the mid-1990s. Recently, however, a number of companies have announced plans to build and operate additional IGCC facilities in the US (3).

These plants have yet to maintain better than 80% availability after more than 10 years of operation. Improved process control strategies are needed to ensure optimum operation over the full range of operating conditions. Real time coal quality analysis is needed to stabilize the coal gasifier process. Several areas of instrumentation development are warranted by the challenging physical conditions of the high temperature, abrasive, slagging gasifier environment. Other areas of the IGCC process face unique challenges that require development efforts to achieve the high availability rate needed for economic viability.

IGCC plants have not been demonstrated larger than 300 MW. For Desert Rock, more/larger gasifiers and several combustion turbines would be needed to attain 1500 MW. This technology is promising, but needs much development funding before the investment community would take on the risk of building such a large IGCC facility.

B. Environmental: This is a process control option

C. Economic: IGCC has higher capital costs than conventional PC plants (3).

IGCC has not demonstrated the typical 85-95% PC plant availability factors necessary for viable on-going profitable operation.

Historically, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. Such conditions are changing toward the more rapid advancement of the IGCC option. IGCC is a versatile technology and is capable of using a variety of feed stocks. In addition to various coal types, feed stocks can include petroleum coke, biomass and solid waste. Along with electricity production, IGCC facilities are able to co-produce other commercially desirable products that result from the process. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Troph fuels (3).

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.
In 1994 EPA established the Environmental Technology Council (ETC) to coordinate and focus the Agency's technology programs. The ETC strives to facilitate innovative technology solutions to environmental challenges, particularly those with multi-media implications. The Council has membership from all EPA technology programs, offices, and regions and meets on a regular basis to discuss technology solutions, technology needs and program synergies. One of the technologies identified as a promising option to address the production of energy from coal in an environmentally sustainable way is IGCC. This technical report is part of the ETC initiative and supports the combined efforts of EPA and the Department of Energy to advance the use of IGCC technology (3).

IV. Background data and assumptions used:

(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)

(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(4) Wabash River IGCC Topical Report 2000 – www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(5) Pioneering Gasification Plants (DOE) – http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(6) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75
(7) ISA-2005 "I & C Needs of Integrated Gasification Combines Cycles" Jeffrey N. Phillips, Project Manager, Future Coal Generation Options, Electric Power Research Institute – presented at the 15th Annual Joint ISA POWID/EPRI Controls and Instrumentation Conference, 5-10 June 2005, Nashville, TN

V. Any uncertainty associated with the option

Medium. Integrated Gasification Combined Cycle (IGCC) is still a relatively new technology. There are coal gasification electric power plants in the US and other nations.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Desert Rock Energy Facility Invest in Carbon Dioxide Control Technology

I. Description of the mitigation option

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

CO_2 emissions are not regulated; however, they are the primary Greenhouse gas that causes global warming.

In June 2005, the Climate Change Advisory Group was created in New Mexico as the result of an executive order from the Governor. The Climate Change Advisory Group (CCAG) is tasked with preparing an inventory of current state (New Mexico) Greenhouse gas emissions, as well as a forecast of future emissions. An action plan with recommendations to reduce Greenhouse gas emissions in New Mexico is also being prepared (3).

The process of generating electricity is the single largest source of greenhouse gas emissions in the United States (34 percent) [4]. CO_2 emissions. The Desert Rock Energy Facility will contribute approximately 11,000,000 Tons/yr CO_2 emissions (5, 6).

Desert Rock is a new proposed power plant in the Four Corners area. Technology is now available to capture and store CO_2 emissions. Many of these technologies are easier and less expensive if integrated into the design and construction of the power plant, rather than added later as retrofits. Retrofitting generating facilities for Carbon Capture and Storage (CCS) is inherently more expensive than deploying CCS in new plants (7).

CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001)

This mitigation option is for Desert Rock Energy Facility and any other proposed power plants to invest into CO_2 emissions control and capture technologies. Desert Rock is in a unique situation to set an example and take the lead in this emissions reduction field.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period including a discussion of CO2 emissions. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Reduced CO_2 emissions
Tradeoffs: None
Burdens: CO_2 control technology is expensive. Burden would be on the power plant; however, there may be some funding for the innovative technologies that would be used.

II. Description of how to implement

A. Mandatory or voluntary
Voluntary

Differing Opinion: According to experts, Desert Rock, if built, would be the seventh largest source of greenhouse gas pollution in the Western United States. It is expected that Desert Rock will emit over 11million tons of carbon dioxide per year. Emission controls on carbon dioxide will most likely be required in the very near future. Carbon dioxide emission reduction technology should be mandatory on the Desert Rock facility.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Region 9 Air Program
Navajo Nation Air Programs
Industry leadership

EPA Climate Protection Partnership is a possible or New Mexico's San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) are possible vehicles for this mitigation option.

III. Feasibility of the option

A. Technical: Technologies exist; many are in the research and development phase. Technological components are commercially ready in unrelated applications (7).

B. Environmental: Capturing and storing CO_2 emissions is difficult. Integrated systems have yet to be constructed at necessary scales. Feasibility question remains whether CO_2 could be stored without substantial leakage over time

C. Economic: Capturing and storing CO_2 emissions can be expensive.

IV. Background data and assumptions used

(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Climate Change Advisory Group (CCAG) homepage: http://www.nmclimatechange.us/index.cfm
(4) EPA Climate Protection Partnerships: http://www.epa.gov/cppd/other/energysupply.htm
(5) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(6) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(7) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75

V. Any uncertainty associated with the option High

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Federal Land Manager Mitigation Agreement with Desert Rock Energy Facility

I. Description of option

Background

Sithe Global Energy (Sithe) is proposing the Desert Rocky Energy Facility (DREF) on the Navajo Nation in northwestern New Mexico. The proposed facility would be within 300 km of 27 National Park Service units, nine of which are Class I areas, and six are U.S. Forest Service Class I areas. The proposed facility will have two 750 megawatt pulverized-coal boilers, and would be well-controlled for a coal-fired power plant. SO2 emissions would be controlled to 3,315 tons per year with Wet Limestone Scrubbers, and NOx emissions would be controlled to 3,315 tons per year with Low-NOx burners and Selective Catalytic Reduction. Despite these controls, the National Park Service and U.S. Forest Service have concluded that the emissions from DREF, absent mitigation measures, would have an adverse impact on visibility at four or more Class I areas in the region. There are also concerns with the emissions contributing to cumulative negative impacts in the region as a whole.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Sithe, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the DREF. Sithe and the federal land managers (FLMs) both sought to avoid a formal adverse impact determination that would jeopardize the issuance of the air quality permit. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006.

In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.

Both the National Park Service and the U.S. Forest Service have asked EPA to include the mitigation measures in the PSD permit. In the absence of the terms of the agreement in principle included as part of the final PSD permit, Task Force members are interested in ensuring the measures will be put in place to avoid adverse impacts to air quality related values in Class I areas and the region as a whole will be avoided throughout the life of the facility.

Sulfur Dioxide Mitigation

The following options outline the sulfur dioxide mitigation strategy for the DREF. The choice between Option A or Option B shall be made by Sithe or its assigns prior to the commencement of DREF plant operations.

Option A: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe[1] shall develop or cause to be developed a capital investment project or projects that generate Emission Reduction Credits from physical and/or operational changes that result in real emission reductions at one or more Electric Generating Units[2] (EGUs) within 300 km of the DREF and retire sulfur dioxide[3] Allowances in accordance with the following:

- The number of sulfur dioxide Emission Reduction Credits required for the respective calendar year shall be determined by DREF's actual sulfur dioxide emissions, in tons, plus 10%, measured as set forth in the next paragraph below.
- The amount of Emission Reduction Credits achieved would be determined by comparing the emission rate (in tons) during the year for which the reduction is claimed to a baseline emission rate. The baseline emission rate shall be the average emission rate (in tons per year) during the two-year period prior to any emission reduction taking place.
- Acceptable sulfur dioxide Emission Reduction Credits under this condition shall be allowances originating from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73[4] and that are located within 300 km of the DREF facility.
- The vintage year of the Emission Reduction Credits shall correspond to the year that is being mitigated. Sithe shall retire the required Emission Reduction Credits by transferring an equivalent number of Allowances into account #XXX with the U.S. EPA Clean Air Markets Division[5]. Except for Sithe's purposes under Title IV, these retired Allowances can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD. However, surplus Emission Reduction Credits could be used at the discretion of the holder of the credits.
- Sithe shall submit a report to the EPA Region 9 Administrator (or another party acceptable to the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted; amount, facility, location of facility, vintage of Emission Reduction Credits retired; proof that Emission Reduction Credits/Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Emission Reduction Credits/Allowances.

Due to the actual emission reductions obtained from nearby sources under this Option, the Federal Land Managers prefer this approach to mitigating DREF's air quality impacts.

Or,

Option B: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe shall obtain and retire sulfur dioxide "Mitigation Allowances" from one or more EGUs within 300 km of the DREF in accordance with the following:

- In addition to those Allowances required under Title IV, the required number of sulfur dioxide "Mitigation Allowances" for the respective calendar year shall equal DREF's actual total sulfur dioxide emissions, in tons.
- Acceptable sulfur dioxide "Mitigation Allowances" under this condition shall be from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73 and that are located within 300 km of the DREF. However, the total annual cost of "Mitigation Allowances" purchased beyond those regular Allowances required by Title IV is not to exceed three million dollars[6]. Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
- The vintage year of the "Mitigation Allowances" shall correspond to the year that is being mitigated. Sithe shall retire these "Mitigation Allowances" by transferring them into account #XXX with the U.S. EPA Clean Air Markets Division. These retired "Mitigation Allowances" beyond Title IV can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD.

- Sithe shall submit a report to the EPA Region 9 Administrator (or another party subject to approval of the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted from the DREF; amount, facility, location of facility, vintage of Allowances retired; proof that Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Allowances.

Additional Air Quality Mitigation
If Sithe chooses Option A, it will contribute \$300,000 annually toward environmental improvement projects that would benefit the area affected by emissions from DREF, including the Class I areas and the Navajo Nation. If Sithe chooses Option B, it will contribute toward environmental improvement projects an amount equal to the \$3 million cap described under Option B above, minus the cost of the Mitigation Allowances, up to a maximum of \$300,000. Appropriate projects will be determined jointly by the Federal Land Managers, Navajo Nation EPA, the Desert Rock Project Company and Diné Power Authority, and may include projects that would reduce or prevent air pollution or greenhouse gases, purchasing and retiring additional emission reduction credits or allowances, or other studies that would provide a foundation for air quality management programs. Up to 1/5 of the contributions can be dedicated to air quality management programs. The remaining contributions shall be used to support projects that mitigate greenhouse gas emissions or criteria pollutants impacts. The Desert Rock Project Company shall have the ability to bank the emission reduction credits achieved through these projects and be entitled to these credits to comply with future greenhouse gas emission mitigation programs. Mitigation and contributions toward environmental improvement projects shall not occur before operation of the Desert Rock Energy project begins.

And,

Sithe will reduce mercury emissions by a minimum of 80% on an annual average using the air pollution control technologies as proposed in the permit application, i.e. SCR, wet FGD, hydrated lime injection, and baghouse. In addition, Sithe will raise the mercury control efficiency to a minimum of 90% provided that the incremental cost effectiveness of the additional controls (such as activated carbon injection or other mercury control technologies) does not exceed \$13,000/lb of incremental mercury removed. Compliance with this provision will be determined by installation and operation of an EPA-approved mercury monitoring and/or testing program. In operating periods when a minimum of 80% mercury control (or 90% as noted above) is not technically feasible due to extreme low mercury concentrations in the burned coal, Sithe will work with EPA to establish a stack mercury emission limit in lieu of a percent reduction, for the purposes of demonstrating compliance.

Examples of Mitigation Strategies

Example #1:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, Sithe would be required to reduce SO_2 emissions at another source (or sources) within 300 km by 3,300 tons. These credits can be used to meet the requirements of the acid rain program under Title IV of the Federal Clean Air Act provided that the physical and/or operational change occur on one or more EGUs.

Example #2:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, suppose Sithe reduces SO_2 emissions at another source (or sources) within 300 km by 4,000 tons. In this case, Sithe would have created 700 tons of surplus SO_2 Emission Reduction Credits that it may use as it sees fit.

Example #3:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from any source, anywhere, plus up to 3,000 tons of SO_2 “Mitigation Allowances” from another source (or sources) within 300 km, provided that the total cost of the “Mitigation Allowances” does not exceed \$3 million (in 2006 dollars). If each “Mitigation Allowance” costs at least \$1,000, Sithe would be done.

Example #4:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from one or more EGU sources. For the remaining 3000 SO2 “Mitigation Allowances”, Sithe may choose, as an option, to obtain 9000 NOx emission reduction credits from physical or operational changes of one or more NOx emission sources within 300 km.

Example #5:
Suppose Sithe obtains the necessary SO_2 reductions through a capital investment project (Option A), or purchases SO_2 Mitigation Allowances (Option B) at a cost of \$2.7 million or less. Sithe would then contribute the maximum \$300,000 to the environmental improvement fund because the total annual costs (allowances plus contribution) would be below the \$3 million cap. On the other hand, if the mitigation allowances cost more than \$2.7 million, Sithe would contribute the difference between the \$3 million cap and the actual cost of the Mitigation Allowances (i.e., if allowance costs equal \$2.9 million, the environmental improvement fund contribution would be \$100,000).

Implementation
The clearest way for these measures to be implemented would be to include them in the PSD permit. Since EPA Region 9 is the permitting authority in this case, that agency would be responsible for including the measure in the permit. Absent including the measures in the permit, other ways of ensuring the mitigation measure will take place are being explored. The FLMs prefer that the mitigation measures be federally enforceable regardless of the mechanism ultimately used.

III. Feasibility of the option
By agreeing to the mitigation measures, Sithe has implicitly affirmed the feasibility of the measures. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

Background Data and Assumptions
The suggested mitigation measures are taken from the agreement-in-principle between Sithe Global Power and the FLMs. Estimated emissions from DREF come from the draft permit.

V. Any uncertainty associated with the option
The uncertainty in this option involves how stakeholders can be assured the measures will actually happen.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] References to Sithe include its subsidiary "Desert Rock Energy Company, LLC" which will be the owner of DREF (referred to herein as the Desert Rock Project Company).
[2] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain real emission reductions at sources other than EGUs.

[3] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking emission reductions, nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.

[4] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.

[5] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking Emission Reduction Credits, Sithe may obtain real emission reductions at sources other than EGUs. Nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.

[6] All costs referenced in this document are base-year 2006 dollars that will be adjusted for inflation by using the consumer price index.

FUTURE POWER PLANTS

Mitigation Option: Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Energy related projects in the Greater Four Corners Region (NM, CO, AZ, UT and WY) are expected to continue to grow at or above current rates. Population and related commerce growth in the 12 county local Four Corners Region (NM, CO, AZ, UT) grew at a brisk rate of 23.8% during the 1990s (1). Future electric power demand will require new power plants and transmission grid capacities. Alternative future “clean coal” power generation technologies such as, FutureGen, Integrated Gasification Combined Cycle (IGCC), and advanced fossil fuel power plants (with carbon capture and sequestration (CCS) technologies) and renewable energy facilities (e.g., wind farms, solar arrays, …) will be needed to accommodate this growth, as well as the increasing demand outside the Four Corners area. Given the size of the western coal reserve and its relatively inexpensive cost compared to natural gas, commercial IGCC power plants could potentially play a role in meeting the region’s future “clean” power needs.

Overview: A power plant based on IGCCtechnology combines or integrates a coal gasification system (gasifier and gas clean-up systems) with a highly efficient combined cycle power generation system. There are a variety of coal gasification technologies in various stages of development that are designed to produce clean synthesis gas (syngas) from coal. The combined cycle unit includes a gas turbine set consisting of a compressor, burner and the gas turbine coupled with a heat recovery steam generator (HRSG). The steam generated in the HRSG, as well as any excess steam generated in the gasification process that is not used elsewhere in the system, is used to power a steam turbine. An IGCC unit has the potential to achieve similar environmental benefits and thermal performance as a natural gas fired combined cycle power generation unit. The use of relatively low cost coal as a feedstock is the one of the main advantages of coal-based power plants. The ability of an IGCC unit to use coal while generating lower air emissions than conventional coal technologies has lead to increased interest in the technology. While IGCC is a promising technology, it has not completely commercially developed. Two small 260 MWe IGCC plants, the Wabash River Plant in Indiana and the Polk Plant in Florida, have been operating for over a decade. Originally built as demonstration plants, reliability of the IGCC units has generally improved over time with gasifier capacity factors in the range of 80% demonstrated in a number of years (2). (Note: the Polk Power Station IGCC unit has only had one year of operation where the gasifier CF was greater than 80% and two years where the CF was near 80% in the 10+ years of operation.) Currently there are at least five separate permit applications for commercial size IGCC plants in the continental United States. Four of these applications are for plants exceeding 600 MWe nominal capacity.

The operation of the major chemical and mechanical process components of a typical coal based IGCC power plant can be summarized as follows (3):

- The gasifier produces syngas by partially oxidizing coal in presence of air or oxygen.
- The ash in the coal is converted to inert, glassy slag.
- The syngas produced from the gasifier is cooled.
- The syngas is cleaned to remove particles.
- The slag and other inert material are collected to be used to make some products or can be safely discarded in the landfill.
- The mercury is removed by passing syngas through the bed of activated carbon.
- The sulfur removed from the syngas is converted into elemental sulfur or sulfuric acid for sale to chemical or fertilizer companies.
- The clean syngas can either be burned in a combustion turbine/electric generator to produce electricity or used as a feedstock for other marketable chemical products.

- Steam produced in the HRSG from the hot combustion turbine exhaust, as well as additional steam that has been generated throughout the process, drives a steam turbine to produce additional electricity.
- The stream exhausted from the steam turbine is cooled and condensed back to water. The water is then pumped back into the steam generation cycle.

Benefits:

- For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM) and mercury (Hg), IGCC is lower polluting than the current generation of traditional coal-fired power plants. It is potentially as "clean" a NOx emitter (< 0.3 lb/MW-hr) as for NGCC plants (4).
- The removal of sulfur compounds, particulates and mercury is more efficient in an IGCC because the removal can take place before the gas is burned (fuel gas) instead of removing the compounds from the exhaust gases following combustion (flue gas).
- The water requirement for the IGCC process is approximately one-third less than that of a pulverized coal plant.
- Solid waste generation at an IGCC power plant is less than that of a PC plant.
- IGCC plants are more flexible in terms of fuel feedstock because they can utilize a variety of fuels, such as coal, biomass, and refinery by-products such as petroleum coke (petcoke). In general, IGCC units are designed to use only one type of coal (i.e. bituminous, sub-bituminous or lignite), but can handle a variety of coals from within the same coal type.
- The CO_2 emissions from an IGCC unit can be higher than from a conventional coal power plant (3). However, based on current technology, it is believed that capture of CO_2 emissions from IGCC plants would be more energy efficient than capture from a conventional coal fired power plant.
- IGCC plants operate at efficiencies of about 40% but have the potential to be as high as 45% (or higher if fuel cells are used). By comparison, conventional combustion-based power plants have efficiencies that range from about 33% to 43%.

Burdens (or deployment barriers):

- General lack of commercial-scale operating experience, especially at Four Corners altitudes.
- Doubts about plant financial viability without subsidies. IGCC has significantly higher capital costs, nominally approximately 20% or higher than the cost for conventional PC plants (Wayland, 2006).
- Low plant reliability, demonstration of commercial plant reliability and capacity factor remains a concern.
- Without carbon capture, an IGCC can have a higher carbon footprint compared to a conventional PC plant. However, the lower total gas flow, the higher percentage of CO_2 in the gas stream, combined with the high operating pressure of the gas stream, makes it easier to recover CO_2 from the syngas in IGCC power plants than from flue gas in conventional coal power plants, based on current technology.
- IGCC carbon capture and sequestration (CCS) technologies have not yet been demonstrated at commercial scale. However, once CCS is demonstrated, IGCC has a potential advantage in capturing and sequestrating CO_2 at lower costs for the reasons stated in the bullet above.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary to look at IGCC as a future clean power generation option for future power plants in the Four Corners area.

B. Indicate the most appropriate agency(ies) to implement

Policy options for use of Integrated Gasification Combined Cycle Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), State or Tribal Environmental Protection Agencies.

III. Feasibility of the option

A. Technical: There is some concern about the feasibility of IGCC power plants at high altitude, elevated temperatures and using western fuels. High altitudes and elevated temperatures lead to significant derations of the power output from the gas turbine portion of the IGCC unit. Turbine manufacturers are working on ways to overcome this altitude deration but, to-date, no solutions have been developed and/or demonstrated.

Carbon dioxide capture technology from IGCC units is still in its research and development phase. To be more cost competitive, a number of technology improvements will need to be made in IGCC plant design; including larger, higher pressure and lower cost quench gasifiers (6). In addition, new and improved gas turbines will be needed that enable air extraction across the operating range of ambient temperatures and with hydrogen firing (7).

Carbon capture and sequestration technologies have potential to substantially reduce carbon emissions into the atmosphere. However the given the current cost of carbon capture and sequestration technologies, it will not be viable solution without a carbon penalty. CO_2 sequestration is also a site-specific geological issue. Options to address this issue include:

- Locating the IGCC unit in an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Pipe the captured CO_2 from an IGCC unit to an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Gasify the coal close to an area suitable for geologic sequestration, EOR, EGR or ECBMR and then send the gas for the power production (although this option does not receive the efficiency benefits associated with a fully integrated IGCC unit).

Currently in the US there are two small IGCC plants, the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana, using coal to make electric power as the primary product. These plants were funded and built in the mid-1990s as demonstration plants by DOE. Recently, however, five companies have applied for and in few cases already received permits and at least five companies have announced plans or issued letters of intent to build and operate IGCC facilities in the US. American Electric Power is proposing to build two 629 MW power plants in Ohio and West Virginia – although the projects have been put on hold due to concerns over project cost escalation (as have several other utilities) (8). Xcel Energy is investigating building an IGCC plant with CO_2 capture and sequestration. Duke and Tampa Electric have received tax credits to help reduce the cost of building IGCC power plants under the Energy Policy Act of 2005.

B. Environmental: For traditional pollutants such as NOx, SO_2, PM and Hg, IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. There are a number of concerns related to the geologic sequestration of CO_2, whether or not the CO_2 is from an IGCC unit. These concerns include, but not limited to the following:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights associated with the sequestered CO_2 be addressed

- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: IGCC has higher capital costs than conventional PC plants (9). Historically – and currently, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. IGCC can be a versatile technology and is capable of using a variety of feedstocks. In addition to various coal types, feedstocks can include petroleum coke, biomass and solid waste.

Along with electricity production, IGCC facilities, if designed to do so, can co-produce other commercially desirable products. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Tropsch fuels (10).

There is not a consensus about the relative costs of carbon capture technology for various plants. General consensus is that, given current technology, it is less expensive to capture CO2 from IGCC plants than from any other coal-based plant, as well as NGCC plants (11). According to an MIT study, today the capital cost (in 1999 dollars?) of CO_2 capture and separation is $1730/kW, which will reduce to $1433/kW in 2012. The CO_2 capture and separation cost for a NGCC power plant is about $1120/kW today, which will reduce to $956/kW in 2012 (12). There are many uncertainties with regards to the costs of CCS.

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.

IV. Background data and assumptions used:

(1) City of Farmington Draft Consolidated Plan, 2004, June
(2) Coal-Based IGCC Plants – Recent Operating Experience and Lessons Learned. Gasification Technologies Conference, Washington, DC (October 2006).
(3) Pioneering Gasification Plants (DOE): http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(4) Wayland, R.J., 2006, U.S. EPA's Clean Air Gasification Activities, Gasification Technologies Council, Winter Meeting January 26, Tucson, Arizona
(5) Blankinship, Steve. "Amid All the IGCC Talk, PC Remain the Go-To Guy." Power Engineering International.
(6) Revis, James, 2007, Clean Coal Technology Status: CO_2 Capture & Storage *Technology Briefing for COLORADO RURAL ELECTRIC ASSOCIATION, February 19*
(7) Wabash River IGCC Topical Report 2000 - www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(8) American Electric Power permit application for proposed IGCC power plant in Great Bend, Ohio and Mountaineer, West Virginia. http://www.aep.com/about/igcc/technology.htm
(9) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(10) IGCC & CCS Background Document. 2006, State Clean Energy-Environment Technical Forum Integrated Gasification Combined Cycle (IGCC) Background and Technical Issues June 19
(11) Clayton, S.J., Stiegel, G.J., and Wimer, J.G., 2002, Gasification Technologies Product Team U.S. Department of EnergyU.S. DOE's Perspective on Long-Term Market Trends and R&D

Needs in Gasification 5th European Gasification Conference Gasification – The Clean Choice Noordwijk, The Netherlands April 8-10
(12) Herzog, Howard. “An Introduction to CO_2 Separation and Capture Technologies.” MIT Energy Laboratory (1999).

V. Any uncertainty associated with the option (Low, Medium, High):
Medium to High, particularly when coupled with CCS as both are developing technologies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Carbon (CO_2) Capture and Sequestration (CCS)

I. Description of the mitigation option

Carbon Capture and Sequestration (CCS) generally consists of removing carbon in the form of CO_2 from either the fuel gas stream; syngas of an Integrated Gasification Combined Cycle (IGCC) power plant or the flue gas stream of other fossil fuel power plants (i.e. pulverized coal, including supercritical pulverized coal (SCPC) and ultra-super critical pulverized coal (USCPC), and natural gas (NGCC) units) compressing and transporting the CO_2 to the sequestration site and sequestering the CO_2. Sequestration can consist of either injecting the CO_2 into a deep saline aquifers or using the CO_2 for enhanced oil recovery (EOR), enhanced natural gas recovery (EGR) or enhanced coal bed methane recovery (ECBMR). Utilization of CCS in combination with other mitigation options such as alternative fuels, energy efficiency and renewal energy would mitigate the potential greenhouse gas (GHG)/climate change impacts of using fossil fuels for power generation.

Overview:

Currently, there are two generic types of CO_2 removal solvents available:

- Chemical absorbents (i.e. amines) that react with the acid gases and require heat to reverse the reactions and release the CO_2
- Physical absorbents (i.e. Selexol and Rectisol) that dissolve CO_2

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. The Selexol process requires less energy than amine-based processes as long as the operating pressure is above 300 psia. At lower pressures, the amount of CO_2 that is absorbed per volume of solvent drops to a level that generally favors the use of an amine system.

Rectisol: Rectisol is the trade name for a CO_2 removal process that uses chilled methanol. In the process, methanol at a temperature of approximately –40 °F absorbs the CO_2 from the gas stream at a relatively high pressure, generally in the range of 400 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. While the methanol solvent is less expensive than the Selexol solvent, the Rectisol process is more complex, has a higher capital cost and requires costly refrigeration to maintain the low temperatures required. It does, however, provide for the most complete removal of CO_2.

Cryogenic coolers are also currently shown to capture CO2 from the combustion exhaust. The cost of CO2 capture is generally estimated as three fourth of the whole carbon capture, storage, transport, and sequestration system. Currently the average cost of carbon capture is about $150/ton by using current technology is high for carbon emission reduction purposes (1). In order to transport and sequester the CO_2, the gas must be compressed to 2000 psia or higher. Research is underway to find better technologies for carbon capture. Presently, the most likely identifiable options apart from absorbents for the carbon separation and capture are (1):

- Adsorption (Physical and Chemical)
- Low-temperature Distillation
- Gas separation Membranes
- Mineralization and Biomineralization

Benefits:

- CO_2 that would otherwise be emitted to the atmosphere is sequestered.
- If used for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) or Enhanced Coal Bed Methane Recovery (ECBMR), the CO_2 from power plants is put to beneficial use and could replace some or all of the natural CO_2 that is currently used for those purposes as well as recover fossil fuel.

Burdens (or deployment barriers):

- Currently there are no power plants in the world that perform CCS, so the integration of the power plant technology with the CCS technology has yet to be proven.
- The capital and O&M costs for CCS are significant and adversely impact the cost of electricity (COE). The cost of electricity will increase by 2.5 cents to 4 cents/Kwh if current carbon capture technologies are added to electrical generation(1).
- No large-scale tests of deep saline aquifer injection have been performed to-date. The Sleipner project in Norway's North Sea is the world's first commercial carbon dioxide capture and storage project(2). CO2 is extracted from gas production on Statoil's Sleipner West Field in the Norwegian North Sea. Started in 1996, it sequesters about 2800 tons of carbon dioxide each day and injects into Utsira sandstone formation (aquifier)(3).
- No environmental laws, rules or procedures are in place for CCS projects.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary in the near term; mandatory as laws, rules and procedures are established.

B. Indicate the most appropriate agency(ies) to implement

Environmental Protection Agency (EPA), Department on Energy (DOE), State Environmental Protection Agencies.

III. Feasibility of the option

A. Technical:

IGCC

In IGCC power plants, CO_2 can be captured from the synthesis gas after the gasification process before it is mixed with air in a combustion turbine. The CO_2 is relatively concentrated (50 volume %) and at high pressure which provides the opportunity for lower cost for carbon capture (4).

While proven carbon capture technology is available for IGCC plants, there are currently no IGCC facilities in the world that capture, compress and sequester CO_2. Depending on the IGCC technology and the carbon capture technology used, it is estimated that carbon capture and compression could add 35 - 50% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2, both from a demonstration (pre-permitting) and ongoing operations perspective.

A number of IGCC technology vendors are working on improvements to their gasifiers that allow for easier CO_2 capture at reduced capital and O&M cost. In addition, a number of firms are working on improved CO_2 capture systems, with most efforts in the area of enhanced or advanced amine systems. It is too early in the development process to verify or quantify the potential cost and performance benefits of these new design efforts.

Another concern is the fact that there is currently no large combustion turbine commercially available that is capable of burning the hydrogen rich gas that would result from an IGCC plant with CCS.

SCPC/USCPC

While proven carbon capture technology is available for SCPC/USCPC plants (currently limited to amine systems), there are currently no SCPC/USCPC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 65 - 100% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

A number of projects are currently underway to try to improve the capture of CO_2 from SCPC/USCPC units in terms of removal efficiency and capital and O&M expenditures. Generally, these projects are targeting 90% capture of CO_2, although there is a general belief that the optimal/achievable reduction level will be less. EPRI and Alstom are working on a chilled ammonia (chemical absorbent) system. A 5 MW slipstream chilled ammonia pilot system will go into operation in Wisconsin in the fall of 2007. According to EPRI, the goal for the project is to reduce the cost for CO2 capture and compression by approximately 66% versus the cost of conventional amine systems. While the exact costs and efficiency gains of the chilled ammonia system are not known at this time, it is known that the system efficiency will decrease in warmer climates.

Babcock & Wilcox (B&W) is currently working on a design for a 500 MW oxygen fired, recirculating gas stream (oxy-fired) boiler for Sask Power in Canada. This unit would use oxygen from an air separation unit (ASU) instead of air for combustion. This use of oxygen means that less NOx is formed (approximately 65% less) in the combustion process and that the resulting flue gas is mainly CO_2 (up to approximately 80%). The flue gas stream, after removal of particulates, SO_2 and moisture, would be recirculated through the boiler, removing a portion (20 - 35%) of the CO_2 with each pass. B&W expects to start testing the design at their 30 MW Clean Environment Development Facility (CEDF) in Alliance, Ohio in June of 2007. Net power output before CCS from the 500 MW unit is expected to be on the order of 350 MW. Additional power will be required to compress and sequester the captured CO_2.

In addition, a number of vendors are working on enhanced/advanced amine systems that they believe will outperform current amine systems.

NGCC

While carbon capture technology is available for NGCC plants (currently limited to amine systems), there are currently no NGCC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 40 - 80% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

B. Environmental: There are currently no environmental laws, rules or procedures in place for CCS projects. Issues that need to be addressed include, but are not limited to:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights issues associated with the sequestered CO_2 be addressed
- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: The capital and O&M impacts of CCS are significant and will result in substantial increases in the cost of electricity.

IV. Background data and assumptions used:

1) Carbon Capture Research. U.S. Department of Energy
<http://www.fossil.energy.gov/programs/sequestration/capture/>
2)Carbon Capture and Sequestration Technologies, MIT.
<http://sequestration.mit.edu/>
3) Carbon Dioxide storage prized. STATOIL.
<http://www.statoil.com/statoilcom/SVG00990.NSF?OpenDatabase&artid=01A5A730136900A3412569B90069E947>
4) Carbon Sequestration. National Energy Technology Laboratory.
<http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html>

V. Any uncertainty associated with the option (Low, Medium, High)

High, as the integration of power generation and CCS is a developing and undemonstrated technology and there are currently no laws, rules and procedures are established to address CCS.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits

I. Description of option

Summary of Option
Agreements regarding mitigation of air quality and air quality related value impacts negotiated between PSD permit applicants and parties other than the permitting authority should be incorporated into the PSD permit and made federally enforceable. If the other party is a federal land manager, there should not have to be a formal declaration of adverse impact before the agreement is made part of the permit.

Background
A primary goal of the PSD program is to protect air quality and air quality related values in areas that attain the National Ambient Air Quality Standards, specifically certain National Parks and Wilderness areas (i.e., "Class I" areas). If representatives of a proposed new source are willing to mitigate the predicted impacts of the new facility, then the permitting authority should honor this intent to reduce air pollution impacts at Class I areas by including mitigation measures in a PSD permit.

This issue arose in the context of federal land manager (FLM) review of the Desert Rock Energy Facility permit application. Federal land managers responsible for "Class I" areas are responsible for reviewing PSD permit applications for new sources to determine if that source would cause or contribute to an adverse impact on visibility or other air quality related values. In the immediate Four Corners area, Mesa Verde National Park and Wemminuche Wilderness Area are the closest Class I areas, and would be impacted the greatest by the Desert Rock Energy Facility. However, there are a total of 15 Class I areas that could be impacted by the facility.

Typically, FLMs address potential adverse impacts through consultation with the permit applicant and permitting authority before the permit is proposed, and before any formal adverse impact finding. When it becomes apparent through the modeling analysis that a facility *may* have an adverse impact, applicants are generally willing, and actually prefer, to discuss changes to address those adverse impacts, through tightening down the control technology, obtaining emission offsets, or other methods. State permitting agencies have generally incorporated the agreed-upon mitigation measures directly into the PSD permit, which as a practical matter, makes those agreements enforceable. This process allows for consultation in the case of suspected adverse impacts and avoids delays in permitting or denial of a permit, which may result from a formal finding of adverse impact.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Desert Rock representatives, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the Desert Rocky Energy Facility. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006. In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.

Without the terms of the agreement in principle included as part of the PSD permit, there is no mutually acceptable way to ensure the specific mitigation measures will be enforceable, and therefore, no assurance that adverse impacts to air quality related values in Class I areas will be avoided throughout the life of the facility.

It is unacceptable that the EPA, in July 2006, issued a proposed PSD permit for the facility but did not include the agreed upon visibility mitigation measures. The so called brown curtain of “regional haze” already present which blankets the Four Corners Area blocks visibility. Not only is it ugly, it indicates degradation of the air quality. Visibility mitigation must be enforceable; therefore, visibility measures must be included in the permitting of Desert Rock and any other future coal fired power plants in the Four Corners Area.

II. Description of how to implement

The permitting authority for a given facility would be responsible for including any agreed-upon mitigation measures into a PSD permit. Usually the permitting authority is the state agency responsible for air pollution control; in some cases, however, the EPA is the permitting authority.

Regarding the actual negotiation of any mitigation measures, information regarding the mitigation measure and its effects is exchanged in the permitting process. In some instances the applicant may supply additional information in the form of an air quality modeling analysis and/or control technology analysis to demonstrate to the FLM the effectiveness of the mitigation measures in reducing impacts to AQRVs at the Class I area(s) in question.

III. Feasibility of the option

By agreeing to a mitigation measure, a permit applicant has implicitly affirmed the feasibility of the measure. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

IV. Background data and assumptions used

The PSD program is created at 42 U.S.C. §§7470-7492; implementing regulations are codified at 40 C.F.R. §51.166 and 40 C.F.R. §52.21.

V. Any uncertainty associated with the option

No uncertainties known.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

None

Mitigation Option: Clean Coal Technology Public Education Program

I. Description of the mitigation option

The goal of this option is to educate all stakeholders, particularly the wider public, as to the cost/benefits of the latest clean coal technology during the permitting process for new coal based power generation facilities in the Four Corners. The public who then participates in the hearings and other steps of the permitting process, would be educated and know the pros and cons of the various technological options available to those proposing the project.

According to the Department of Energy, coal will continue indefinitely to be one of the least expensive sources of electric power in the United States. The Four Corners region has abundant coal resources and many stakeholders who wish to capitalize on that abundance to produce energy, jobs and revenue. Technologies for transforming coal to energy vary enormously in cost, and pollution, including release of global warming gases. Research into improved (cleaner) technologies continues, see President Bush's new commitment to the Clean Coal Power Initiative as one example. The public in the Four Corners area needs to be informed and frequently updated as to the status of research and testing in clean coal technology so they can ask educated questions and make educated political decisions and/or demands on policy-makers in the agencies permitting power generation installations in the Four Corners area. This mitigation option lays out a plan for the on-going education of Four Corners stakeholders with regard to the latest, cleanest, safest technologies for converting our generous resource into energy.

This option would require the primary permitting agency for a proposed project to designate early in the process a non-political 'clean coal technology scientist/advocate' whose responsibility it would be to prepare documentation in layman's terms on the latest research and feasibility of clean coal technology and where the proposed technology stands in relation to the current ideal. This individual would make presentations at hearings, be available by phone/internet for consultation with stakeholders, including the media, submit factual information pieces to the Four Corners media on clean coal technology, speak at community meetings, etc. In other words, the scientist/advocate would design and conduct an extensive public relations campaign to education the public during the permitting process.

Many institutions, including the Department of Energy, and educational institutions, conduct research in clean coal technology on an ongoing basis and NGOs like San Juan Citizens Alliance make themselves experts on the issues and could be called upon to educate the public at any given point. The obstacle here is how to ensure that the latest knowledge reaches the lay public when they can use it during the permitting process of new coal-based power plants and/or updates of older units. One way is to tie public education into the EPA permitting process. (Other ideas are welcome.) This option places an additional burden on the EPA in time, energy and cost and therefore indirectly on those proposing the new or updated power plants on to whom the additional costs of this step would be passed.

Participation of an educated public in the permitting process will lead to better long-term decision-making for the Four Corners area.

II. Description of how to implement

A. Mandatory or voluntary:
Mandatory

B. Indicate the most appropriate agency(ies) to implement:

The lead permitting agency, typically the EPA. The Department of Energy might be another appropriate agency; however, it is hard to envision how they could be motivated enough to know when and where their expertise is needed if not tied to the permitting process.

EPA is strongly encouraging companies proposing to build to power plants to meet with the local citizens in nearby communities and regional areas to discuss their plans including their projected emissions if the facility has been announced. In addition, if they are constructing near a non-attainment area for any pollutant, EPA believes it is important to meet with local air planning officials in the non-attainment area. The companies need to be willing to lay everything on the table with respect to technology, emissions, and comparisons to other similar facilities nationwide. The companies are better off actually doing these types of meetings before they even send in the permit application. Oftentimes, people are not opposed to a new cleaner EGU, but they want something done about those older existing units in the area. This hopefully will help educate the community on what the company would like to construct.

Remember once the permitting application arrives and the State proposes the permit for public comment.....some State regulatory requirements may require them to treat any meeting where comments are made about the facility's proposed permit and technology into the public record. Therefore, it would be encouraged that any meetings with the community to occur prior to the permit being public noticed.

Another option for sponsoring a Clean Coal meeting in the 4 Corners area is to invite speakers from Dept. of Energy, EPA, National Labs doing coal related work, and State permitting officials. It would also be okay to invite independent experts. Obviously, the issue becomes funding for such a meeting. Generally, a DOE and/or EPA rep will not cost you anything. Many technology vendors know the clean coal technology in depth and would participate.

Another option is to talk to state Air Quality Bureau chief about applying for special projects funds from EPA to host such an event in the future. It is not certain what type of funds DOE may have available, but they may have funding for such a meeting as well. Another option is for a company to fund as part of an enforcement settlement agreement, or for a consortium of the mining companies and power utilities to fund the meeting location, but the State to do all of the planning and agenda development for the meeting.

It would be strongly encouraged that the state environment department go through the actual permitting process at any meeting clearly showing in a process flowchart the specific points for public comment opportunities since it would be the state process that they would be following. The state environment department also needs to educate the public on the types of comments that actually are considered valid or significant comments.....(examples are great) versus the general "not in my backyard" comments.

Options for on funding, implementation, and a CCT public educational program within existing state PSD permitting programs:

- **Establish a federal/state agency MOU**: A memorandum of understanding (MOU) would provide a mechanism for CCT public information transfer during the PSD permit application. It could facilitate the selection of an independent engineer/ scientist on clean coal technology from nearby leading universities such as Colorado School of Mines or from independent national labs such as National Energy Technology Laboratory or from reputable CCT research non-for profit scientific institution such as Union of Concerned Scientists. The engineer/scientist would provide the public with status on CCT research/demonstration/commercialization as well as comparative advantages or disadvantages of these technologies with the proposed power plant technology (e.g., SCPC plant).
- **Develop and maintain a CCT education/information transfer web-portal**: New commercial power generation technological advancement occur over a relatively long time frame. An easily accessible and updatable source of CCT information and educational material can be provided through a web portal. Argonne has developed a variety of energy web portals, many with public

outreach and some with educational elements (http://ocsenergy.anl.gov/, http://www.onlakepartners.org/). A web based outreach platform can provide CCT educational material on demand in layperson language and can provide public outreach tools for more informed and effective public involvement. Advancements in the clean coal technology could be updated on a regular basis. The state permitting agency could assume web-portal maintenance with an option for independent oversight and feedback from CCT experts. These experts (an engineer/scientist) can be retained to further support these efforts in person at public meetings during breakout public CCT education sessions.

III. Feasibility of the option

A. Technical:
Feasible, these people exist in the Four Corners area; Bill Green is an example of one. The Department of Energy undoubtedly could recommend local or regional experts.

B. Environmental:
Not relevant, no impact

C. Economic:
Retaining such a scientist/advocate will cost money but the reasonable expenses for this individual could be passed by the permitting agency to the organizers of the proposed power generation facility

This may require a regulatory and fee changes by state agencies......include a requirement for such a meeting in the State rules including a fee requirement for the permit applicant to fund the meeting location/facility to host such a meeting in the Regional area of the proposed facility. It would need to be researched and discussed to ensure that it's not prohibited by the CAA.

The ideas for funding of clean coal technology education program (within existing state PSD permitting programs):

- To implement such an effective clean coal technology education program a funding mechanism needs to be worked out between states and EPA. Options include but are not limited to:
    - The permitting fee for the power plan can be increased in order to pay for the the public education outreach program (e.g., web-portal and/or CCT expert).
    - Some non-for profit foundation involved in public education can be contacted to obtain a grant to build the webportal as well as pay for the compensation to experts/scientists.
    - It may be possible to find independent experts/scientists who will be able to provide their time for free for public good but there will still be a need of compensation for travel and lodging.

D. Political:
There is likely to be political resistance to spending additional dollars in this way. Additionally, the effort to educate the public on clean coal technology should be on ongoing effort, not dependent on proposal of power plants; however, it is difficult to figure out how to tie such an independent effort to the motivation and funding that it would take to get it to actually happen.

IV. Background data and assumptions used

Assumptions:
1. Coal continues to be abundant in the Four Corners area and in demand in power generation facilities
2. Stakeholders continue to desire to construct power generation facilities in the Four Corners area using coal, as opposed to transporting it out to other areas for use.
3. A standardized cost-effective perfectly clean technology for use of coal in power generation is years away.

V. Any uncertainty associated with the option (Low, Medium, High)

The only uncertainty that exists involves the degree of success the scientist/advocate would have in educating the public given the apathy sometimes exhibited by the public around these issues

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Mitigation Option: Utility-Scale Photovoltaic Plants

I. Description of the mitigation option

Future Large-scale photovoltaic power plants (solar energy plants) could be built to accommodate future energy demands and offset some of the current coal-based coal fired power demands

Large-scale Photovoltaic power plants would consist of many PV arrays working together. PV electricity generation does not consume fuel and produces no air or water pollution.

The Electric Power Research Institute (EPRI) announced in July 2007 the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington, NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.

Benefits:

- Utilities can build PV plants much more quickly than they can build conventional fossil or nuclear power plants, because PV arrays are fairly easy to install and connect
- Unlike conventional power plants, modular PV plants can be expanded incrementally as demand increases
- Utilities can build PV power plants where they're most needed in the grid, because siting PV arrays is usually much easier than siting a conventional power plant
- Solar energy is clean energy and uses the sun for fuel.

Tradeoffs:
Burdens:

- Photovoltaic systems produce power only during daylight hours, and their output thus can vary with the weather. Utility planners must therefore treat a PV power plant differently than they would treat a conventional plant.
- Using current utility accounting practices, PV-generated electricity still costs more than electricity generated by conventional plants in most places, and regulatory agencies require most utilities to supply the lowest-cost electricity

II. Description of how to implement

A. Mandatory or voluntary

Mandatory (could be added as part of Renewable Energy Portfolio system)

May become more cost effective and implemented voluntarily as the technology continues to mature and power generation stakeholders see economic advantages to solar power.

B. Indicate the most appropriate agency(ies) to implement

State and Federal Governments can pass legislation requiring larger Renewable Energy Portfolios

III. Feasibility of the option

A. Technical –
PV Technology is available and technically feasible

B. Environmental –
PV systems have little adverse environmental impact

C. Economic –
Cost of PV systems to generate power is still more expensive than conventional fossil-fuels

DOE, the Electric Power Research Institute, and several utilities have formed a joint venture called *Photovoltaics for Utility-Scale Applications* (PVUSA). This project operates three pilot test stations in different parts of the country for utility-scale PV systems. The pilot projects allow utilities to experiment with newly developing PV technologies with little financial risk.

IV. Background data and assumptions used

1. DOE Energy Efficiency and Renewable Energy, Solar Energy Technologies Program
http://www1.eere.energy.gov/solar/utility_scale.html

2. PVUSA Solar: a Renewable Ventures Project, http://www.pvusasolar.com/

V. Any uncertainty associated with the option:

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Biomass Power Generation

I. Description of the mitigation option

Power Generation using biomass fuels can potentially reduce net CO2 emissions and other criteria pollutants from 4 Corners area power generation if displacing traditional coal-fired generation and is an option for future power plants in the area. Power from biomass is a proven commercial electricity generation option in the United States. With about 9,733 megawatts (MW) in 2002 of installed capacity, biomass is the single largest source of non-hydro renewable electricity. [1, 2]

Biomass used for energy purposes includes: Leftover materials from the wood products industry, Wood residues from municipalities and industry, Forest debris and thinnings, Agricultural residues, Fast-growing trees and crops, Animal manures. [2]

An aggressive Renewable Portfolio Standard was set in the 2007 NM legislative session. It includes 20% of power generation from renewables by 2020 (for large utilities) and 10% by 2020 (for rural electric cooperatives).
Biomass may be a necessary part of power generation to meet these standards.

In addition a 2005 executive order outlined Greenhouse Gas Emission Reduction Targets. These included reductions of NM Greenhouse gases to 2000 levels by 2012. Biomass power generation may be an alternative source of energy that can offset some of the CO2 emissions from fossil fuel-based combustion.

Benefits

Biomass combustion to produce electricity generates negligible Sulfur Dioxide and it has been shown to produce less Nitrogen Oxide emissions than coal-fired combustion. CO2 is absorbed during biomass growth cycle in photosynthesis and then released during combustion, so the direct combustion of the biomass feedstock can be considered to have a net 0 effect on CO2 emissions. If the biomass fuel can be planted, matured, and harvested in shorter periods of time compare to the natural growth plants then the recycling of CO2 in the environment can be reduced to close to one – third.

Other benefits include rural economic growth, increased national energy security, and using waste products that would otherwise have to be disposed. Using biomass fuel to generate electricity will reduce the greenhouse gas methane in the environment because if discarded in the landfill, the decomposition of biomass fuel generates methane.

Tradeoffs

- Land required for growing biomass.
- Higher nitrogen content of biomass fuel can contribute to higher NOx emission such as in the case of fertilizer used to grow biomass fuel.
- N2O emissions from fertilizer to grow biomass, if used.
- Energy emissions to grow, collect, and transport biomass fuel to plant
- Vehicle and dust emissions from transport trucks
- Energy emissions to dispose of waste
- The particulate emission from the biomass power generating power plant is a real concern. However the particulate emission can be controlled using readily available PM control technologies.

Burdens

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs — the preferred system has transportation distances less than 100 miles.[3]

II. Description of how to implement

A. Mandatory or voluntary

Voluntary. Biomass may offset some of the coal based power generation.
May be necessary under new Renewable Portfolio Standard requirements for New Mexico & Colorado

B. Indicate the most appropriate agency(ies) to implement

Industry Research and Development, State and Federal Policy Support

III. Feasibility of the option

A. Technical – Biomass power generation is a proven commercial technology. Co-firing with fossil fuels may be the most feasible option at this time

B. Environmental – Biomass power generation has some significant advantages over fossil-fuel power generation. As demonstrated by some of the public hearings and objections to a new 35-megawatt plant, proposed to be built in Estancia, NM by Western Water and Power Production LLC., biomass may be a challenging technology to implement.

C. Economic –
A typical coal-fueled power plant produces power for about $0.023/kilowatt-hour (kWh). Cofiring inexpensive biomass fuels can reduce this cost to $0.021/kWh, while the cost of generation would be increased if biomass fuels were obtained at prices at or above the power plant's coal prices. In today's direct-fired biomass power plants, generation costs are about $0.09/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as $0.05/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about $0.04-$0.05/kWh at fall 2000 gas prices.[3]

IV. Background data and assumptions used

1. US DOE Energy Efficiency and Renewable Energy, Biomass Program
http://www1.eere.energy.gov/biomass/technologies.html

2. EIA RENEWABLE ENERGY 2002,
http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/table5.html]

3. US DOE Energy Efficiency and Renewable Energy, State Energy Alternatives
http://www.eere.energy.gov/states/alternatives/biomass.cfm

4. Electricity From: Biomass
http://powerscorecard.org/tech_detail.cfm?resource_id=1

V. Any uncertainty associated with the option: High.
VI. Level of agreement within the work group for this mitigation option: To Be Determined.
VII. Cross-over issues to the other Task Force work groups
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Bioenergy Center

I. Description of the mitigation option

Sunflower Electric Power Cooperative is planning a bio-energy center adjacent to their coal fired electric plant in rural Kansas[1].Three new 700 MW units are planned to supplement the existing 360 MW unit. The bioenergy center promises some CO2 mitigation along with energy efficient and low pollution auxiliary business enterprises. The bioenergy center concept involves a feedlot, dairy, anaerobic digester, algae reactor, ethanol plant, biodiesel plant, and the coal plant. Methane, electricity, ethanol, and biodiesel will be produced. The wastes (water, manure, biogas, nitrogen, phosphorus, flue gas, glycerol, CO2, wet distiller's grain, and ammonia) are used for inputs for the processes, rather than being discarded.

The anaerobic digester processes manure to produce methane to power the ethanol plant. The algae reactor consumes CO2 from the coal plant flue gas, and nitrogen and phosphorus from the anaerobic digester. The reactor then produces oil-rich protein for biodiesel production, with the residue used for livestock feed. The ethanol plant will consume corn and grain sorghum, and produce wet-distillers grain for livestock feed.

Locally, there could be variations on this theme. Excess corn fodder biomass, not fed to livestock, could be burned in the power plant. Only the grain is useful in ethanol production with current technology. Livestock could be omitted and the ethanol plant powered with natural gas.

Benefits: Any burned biomass has close to zero net effect on CO2 emissions from the coal fired power plant. Energy efficient businesses produce ethanol and biodiesel for sale. Local economic growth is enhanced, with increased national energy independence. Waste products are recycled that would otherwise have to be disposed.

Tradeoffs:
Land is needed to grow grain crops
Nitrate run-off from needed fertilizer
Ancillary energy usage, and lowering of CO2 net efficiency, to cultivate, harvest, and transport the crop, and remove waste products

II. Description of how to implement

A. Mandatory or voluntary: Voluntary.
It should be more feasible to plan such an adjunct facility at the proposed Desert Rock Power Plant, rather than at the existing power plants. Livestock and grain crops could be expanded at the NAPI, resulting in short transportation distances. Sithe Global is required to provide financing for local environmentally beneficial projects as an offset for tax benefits. This could help fund the feasibility studies for this project and a portion of the construction costs.

B. Indicate the most appropriate agency(ies) to implement
Navajo Nation, San Juan County, State of New Mexico economic development departments

III. Feasibility of the option

A. Technical – Co-firing biomass in coal plants is proven technology. Ethanol plants are being constructed at a rapid pace. There is a local construction company with extensive experience with ethanol plants. Each bio-energy component has been commercialized to some degree, but the challenge is the integration of these components in an energy center.

B. Environmental – VOC emission output from an ethanol plant could be mitigated by vapor capture routed to the power plant, or to a thermal oxidizer. The thermal oxidizer could accommodate vapors from the biodiesel plant. A portion of the power plant and thermal oxidizer CO2 emissions would be mitigated by the algae reactor. Expanded feedlot activities have associated groundwater, ozone layer (methane), and odor impacts.

C. Economic – Detailed economic modeling is needed along with the engineering studies to provide input to a viable business plan. A renewable energy project should attract grant money and gain tax benefits. Labor infrastructure at the Desert Rock construction site could be leveraged to construct, then operate the bio-center.

IV. Background data and assumptions used

1. "Farming for Energy" Sunflower Electric's Bioenergy Center in Kansas – EnergyBiz Magazine, Jan./Feb. 2007 -- www.energycentral.com

2. Kansas Technology Enterprise Corporation -- http://www.ktec.com/index_Flash.htm

3. Four Corners Air Quality Task Force Mitigation Option "Biomass Power Generation"

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option To be discussed.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Nuclear Option

I. Description of the mitigation option

Nuclear reactor power generation should be considered as a mitigation option. We should not assume that it is too politically controversial for consideration. The mitigation options would lack balance if the taskforce were not to consider a future nuclear power plant. Such a plant would have virtually zero air emissions and global warming impact.

The U.S. Nuclear Regulatory Commission is adding staff to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, which has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. Many of these units will be in the south and southeast, where utilities have prior nuclear experience. NRC has streamlined their processes so standard design certifications will be approved, and the safety design hurdle will not be raised continually. Many of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications.

These designs include the GE AWBR (Advanced Boiler Water Reactor), the Areva EPR (Evolutionary Power Reactor), and the Mitsubishi advanced pressurized water reactor. Bechtel is working on standard, pre-engineered modular designs, so that units can be replicated quickly and cost effectively. Construction time is approximately four to five years. If fifteen units were to be built from now until 2020, there would be a need for 30,000 new high-paying craft jobs. Several utilities are committing to these designs because of the certainty they will be completed on schedule with low risk financing, and their operating experience at similar plants.

There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent convection cooling protection to electrically powered valves and pumps. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. General Electric is offering its ESBWR (Economically Simplified Boiling Water Reactor) and Westinghouse its AP1000, an advanced passive reactor. TVA and Entergy are considering use of this technology. Plants of this type will be among those soon licensed by the NRC.

Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

Opposition will come from perceived plant safety and spent fuel issues. Regional storage of spent fuel already exists in New Mexico. It is likely that Yucca Mountain will be licensed for long term storage. New Mexico should participate in research for the safe long term storage of spent nuclear fuel. There is strong congressional and public recognition that nuclear power generation should be part of the energy portfolio, along with increased renewables, to address climate change. There is also a 20-30% group that opposes both existing and future nuclear power generation. This level of opposition would also be expected in New Mexico, and must be considered in any political process to license a nuclear plant locally. Worldwide, especially in China and India, there is a very active nuclear buildout in progress. Nuclear power generation is actively expanding worldwide, and about to in the United States.

A realistic approach would keep our options open politically, while closely monitoring the re-emergence of the nuclear industry in the United States over the next 5 – 10 years. We should especially follow the operating experience of the new passive cooling reactors which should be on-line in less than ten years.

New Mexico is already in an area of low seismic activity. The additional safety advantage of a passive reactor design should lower public opposition significantly. Much of the anticipated surge of nuclear construction is by existing utilities that already operate conventional nuclear plants. It makes economic sense for many of them to continue in this direction. That argument does not hold in New Mexico, and we should embrace the construction of one or more passive nuclear power reactors as this technology matures.

We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.

A nuclear building program in the Four Corners would greatly enhance the growth of a local and regional high technology professional and vocational workforce. San Juan College would step up with new programs to educate the vocational workforce needed to build and operate a nuclear plant. The college should also benefit from creative financing support similar to that proposed for Desert Rock. The Four Corners and New Mexico would be recognized as an energy focal point in the U.S., with an exceptional balance of conventional, renewable, and nuclear energy generation, along with our strong base in oil/gas production.

Benefits: Zero air emissions impact; No carbon footprint; Cost effective electricity generation; Foster high technology educational and employment basis in the Four Corners; Proximity to current New Mexico and future Nevada spent fuel storage site.

Tradeoffs: Minority negative public opinion related to plant safety and spent fuel containment.

Differing Opinion: While it may be true that nuclear power plants have almost no carbon dioxide emissions (except in construction and in mining, processing and supplying the uranium fuel) and low global warming impact, there are other enormous liabilities which make them, in my opinion, the least desirable alternative to replace fossil fuel-fired power plants.

The availability of fissionable uranium (U-235) is not discussed. The supply will be quite limited, especially if the rate of usage increases significantly. One proposed solution, going to breeder reactor technology, would involve transport of radioactive materials to and from reprocessing plants, entailing enormous problems of safety and security.

The stated maintenance cost of 1.7 cents per Kwh for nuclear plants is deceptive. In all likelihood it does not include the cost of decommissioning the facility at the end of its useful life, nor the totally unknown cost of eventual “permanent” storage of the radioactive waste products. It also does not include any portion of the massive and continuing federal subsidies for nuclear R&D ($145 billion between 1947 and 1998 according to one source).

The issue of permanent storage of radioactive wastes (spent fuel) is not adequately discussed. The federal government and the nuclear industry have had half a century to develop permanent storage facilities; it seems they are no closer to a solution than when they started. Yucca Mountain is not close to viable, the latest blow being a federal court decision upholding the Nevada State Water Engineer’s authority to deny the federal government’s use of groundwater at the site. Even if a permanent storage facility is eventually developed, there is a major moral issue. I do not believe we have the right to impose an almost perpetual guardianship role on future generations (8,000 generations if the estimate of a 200,000 year storage time for plutonium wastes is accurate).

II. Description of how to implement

A. Mandatory or voluntary
B. Indicate the most appropriate agency(ies) to implement

III. Feasibility of the option

A. Technical –
B. Environmental –

We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.

C. Economic –

Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

IV. Background data and assumptions used:

Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up." Vol. 4, Issue 4 (July 07, August 07) “Bechtel sees Nuclear Surge” and “The Nuclear Balance Sheet.”

V. Any uncertainty associated with the option: TBD

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups:

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

OVERARCHING: POLICY

Mitigation Option: Reorganization of EPA Regions

I. Description of the mitigation option

The Four Corners geographic area is under the jurisdiction of three different regions of the Environmental Protection Agency: Colorado and Utah are in Region 8, headquartered in Denver; New Mexico is in Region 6, headquartered in Dallas; and Arizona (and the Navajo Nation, which is in both Arizona and New Mexico) is in Region 9, headquartered in San Francisco.

Due to the abundance of coal and oil and gas in the San Juan Basin energy development in the area is likely to continue. It is becoming increasingly well-documented that the majority of the pollution experienced in the Four Corners area is coming from coal-fired power plants on or near reservation lands in New Mexico as well as oil and gas development throughout the region. The EPA staff engaged in addressing environmental impacts from oil and gas development, and responsible for actually permitting or overseeing permitting of stationary sources (power plants) needs to be located where the pollution is happening and be responsible to the recipients of that pollution as well as to hold its generators accountable.

A permanent EPA human presence within the area of energy development and pollution would sensitize EPA personnel to the issues within the Four Corners area. Creating an interregional office of the EPA with jurisdictional authority in order to include within a single jurisdiction the pollution generating sources and the public lands and communities they impact would improve EPA effectiveness in oversight and permit processing by facilitating communication and focusing feedback.

II. Description of how to implement

Create a permanent inter-region office within the EPA chartered to focus on, and located in, the Four Corners region. The office would assume all regional duties with respect to the Four Corners area, and have responsibility for overseeing state and tribal permitting, permitting stationary sources in the absence of state or tribal permitting, and any activities relating to oil and gas development currently performed by the various regions.

III. Feasibility of the Option

EPA Headquarters, as well as the three regions involved, would need to approve this option. The states and tribes would need to support this option as well.

IV. Background data and assumptions

The statement by Colleen McKaughan of Region 9 to the Durango Herald epitomizes our perception of the sensitivity of Region 9 personnel to the issues in the Four Corners region. As quoted in the Durango Herald on September 15, 2006, Ms. McKaughan, an air-quality expert with the federal Environmental Protection Agency's Region 9, said the Four Corners region has air so clean that it can absorb additional pollutants without harm. She said the EPA had no significant concerns about the proposed coal-fired Desert Rock plant.

V. Any uncertainty associated with the option There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

OVERARCHING: MERCURY

Mitigation Option: Clean Air Mercury Rule Implementations in Four Corners Area

I. Description of the mitigation option

States and tribes are presently drafting regulations (some such as NM and CO now have completed rules, see appendix on NM & CO) to meet the Clean Air Mercury Rule (CAMR) while simultaneously meeting their mission to protect public health and the environment. For states, this means allocating mercury allowances to electric generating facilities to operate. CAMR may eventually have profound effects on the amount of mercury reduced from the affected facilities.

States participating in the Task Force might work in concert to determine if even greater reductions are possible than initially scheduled in CAMR. Some examples of working in concert might include:

- "Incentivizing" early mercury reductions at CAMR-affected facilities;
- Retiring any excess allowances that may exist (Colorado has in effect a "Colorado Citizens' Trust" to effectively permanently set aside excess allowances);
- Addressing the concerns for local mercury impacts ("hot spots") from new and proposed facilities in the Four Corners area by requesting that State air quality permitting agencies consider this hot spot criterion in their decision to approve/disapprove facilities' air quality permit requests (as individual state budgets and their "set aside allowances" may be inappropriate indicators of the impacts the local area might receive from power plants in Four Corners);
- Promoting additional mercury studies (e.g., air deposition) that would benefit Four Corners area (could/should be tied to option #5);
- Requiring early installation of mercury CEMs at facilities (to better gauge effectiveness of various co-control efforts);
    - For example, Mercury CEMs will be installed on 2 of the 4 units at San Juan by 12/31/07 and the other 2 units by 12/31/08.
- Developing more stringent control requirements for facilities in Four Corners Area;
- Other examples as identified.

II. Description of how to implement

A. Mandatory or voluntary:
Could be either mandatory or voluntary depending on the specifics of the option.

Differing Opinion: Since many of Four Corners Area lakes, streams, and rivers are currently under a mercury advisory, mandatory control of mercury is necessary. The health of humans and other living beings is at risk

B. Indicate the most appropriate agency(ies) to implement:
States' environmental (permitting) agencies

III. Feasibility of the option

A. Technical: Some of the technical options may be difficult to implement, especially depending on the timing. That is, CAMR plans are due to EPA by November 2006 and hence options developed here may come too late. However, options developed here could be possibly used in the states' future allocation schemes and/ or approaches surrounding CAMR.
B. Environmental: N/A
C. Economic: Difficult to ascertain as this depends on the specifics of the option developed.

IV. Background data and assumptions used

CAMR information and data are plentiful; however, the long-term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

Basic Information on New Mexico CAMR:

- Rule applicability covers coal-fired EGUs (presently 4 units at San Juan Generating Station and 1 unit at Escalante Generating Station).
- Mandatory mercury monitoring by sources begins 1/1/09.
- Mercury limitations become effective 1/1/10.
- See Tables 1 and 2, below, for mercury emissions data and proposed limitations.
- Monitoring includes installing monitoring systems (CEMS or sorbent traps), certification, performance test, and recording, quality-assuring, and reporting data.
- Initial monitoring performance test is 12 months (calendar year 2009).
- State rules takes state "budget" and turns it into state "cap" with portions of the cap assigned to facilities as facility-wide emission limitations as well as EPA-recommended new source set-aside.
- State rules prohibit participation in trading and banking program.
- State rules establish emissions fees to support one full-time equivalent for implementation of the mercury rules.

Table 1: New Mexico Mercury Emissions Data	
New Mexico Mercury Emissions (1999 EPA data; Tons)	1.09
New Mexico Mercury Emissions (2004 TRI data; SJGS + Escalante; Tons)	0.389
New Mexico Mercury Budget (2010-2017; Tons per year)	0.299
New Mexico Mercury Budget (2018 and after; Tons per year)	0.118

Table 2: New Mexico Mercury Limitations (Per year)						
	2010-2017			**2018 and after**		
	Tons	Ounces	%	Tons	Ounces	%
Total "State Cap"	0.299	9,568	100 %	0.118	3,776	100 %
San Juan Generating Station	0.244	7,808	81.6 %	0.104	3,323	88 %
Escalante Generating Station	0.04	1,280	13.4 %	0.01	340	9 %
New Source Set-Aside	0.015	480	5 %	0.035	113	3 %

Basic Information on Colorado CAMR:

Overview: Colorado's Air Quality Control Commission adopted a rule specific to CO's Utility Hg Reduction Program on 2/6/07. This rule specifies 100% of the state's allowances be transferred into the State's General Account. The State allocates allowances to units based on annual actual emissions, up to Model Rule allocations with an option to access additional allowances based on need through a safety-valve. In addition, the rule requires phased reductions over time on a rolling 12-month average basis, exempting low mass emitters and new units with existing permits in place:

- 2012: Pawnee and Rawhide 0.0174 lb/GWh or 80% inlet Hg capture;
- 2014: 0.0174 lb/GWh or 80% inlet Hg capture; and
- 2018: 0.0087 lb/GWh or 90% inlet Hg capture.

This rule allows for averaging of units at the same plant. The rule also provides soft-landing, requiring Best Available Mercury Control Technology installation if units demonstrate to the State that they cannot meet the performance standard. Finally, the rule includes a provision associated with retirement of allowance accrual, beginning in 2016, 2019 and every five years thereafter, if no separate rulemaking is commenced prior.

Trading: Yes, but allocations are made based on actual emissions.

Allowance Allocations: Up to 95% in phase I and 97% in phase II, with the remainder used for new units. However, actual allocations are made based on actual emissions, which are reduced over time due to state-only Hg emission standards. Therefore allocation amounts are also expected to decrease over time.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – again, the long term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other Task Force work groups

TBD.

Mitigation Option: Federal Clean Air Mercury Rule (CAMR) Implementation on the Navajo Nation

I. Description of the mitigation option

The Environmental Protection Agency (EPA) promulgated the Clean Air Mercury Rule (CAMR) on May 18, 2005. CAMR established a mechanism by which mercury (Hg) emissions from new and existing coal-fired power plants (EGUs) are capped at nation-wide levels of 38 tons/year effective in 2010 and 15 tons/year effective in 2018. EPA then established Hg emission levels for each state and for Indian country in cases where there are existing EGUs; this includes the Navajo Nation. State and Tribal plans to implement and enforce Hg emission levels were to be submitted to EPA by November 17, 2006. State plans can be more stringent than the EPA Model Rule and may or may not allow trading or banking of emissions allowances.

In cases where a State or Indian Tribe does not have an approvable plan in place by the prescribed deadline of March 17, 2007, EPA may implement a Federal plan by May 17, 2007. In order to facilitate this action, EPA published proposed rules on December 22, 2006. These rules are expected to be finalized by May 17, 2007, and will be used to implement CAMR on the Navajo Nation. A major shortcoming of these EPA rules is the lack of provision for meaningful public participation in the process to develop and allocate specific Hg emission limits for existing and proposed EGUs on Navajo Nation lands. This is significant since the Navajo Nation mercury emissions budget is larger than that of either Arizona, New Mexico, or Utah, and almost as large as the budget for Colorado.

The Navajo EPA, Region 9 EPA, and the operating agencies for the Four Corners Power Plant and the Navajo Generating Station – Arizona Public Service Company (APS) and the Salt River Project Agricultural Improvement and Power District (SRP), respectively – have already had discussions regarding a potential allocation methodology for the Navajo Nation. A meeting was held on July 10, 2006, at which Region 9 EPA presented a “strawman” proposal which differed significantly from the EPA model Rule with respect to the amount and disposition of the new source set-aside portion. This proposal has not been well-received by APS and SRP. The degree to which the air quality agencies in the surrounding, contiguous, and sometimes overlapping States of Arizona, Colorado, New Mexico and Utah have been aware of these early meetings is not known. From all appearances it seems that much greater effort should go towards facilitating adequate public participation in this process. The prime responsibility for achieving this rests with Region 9 EPA.

At a minimum the process for allocation of mercury emissions limits to EGUs in Navajo lands should be at least as open to public participation as the most transparent State CAMR process has been. For the Navajo Nation this might include informational meetings and public hearings in Window Rock and Page, Arizona, and Farmington, New Mexico. Final decisions on nature and location of meetings should be negotiated among the various jurisdictional agencies.

II. Description of how to implement

A. Mandatory or voluntary

This should be mandatory. In the past, public participation has been a cornerstone of EPA policy and in fact is mandated in many of their regulations.

B. Indicate the most appropriate agencies to implement

Region 9 EPA, with assistance and cooperation of Navajo EPA and air quality agencies in affected States.

III. Feasibility of the option

A. Technical: Entirely feasible

B. Environmental: Feasible

Economic: Feasible; minor administrative costs to conduct public meetings and hearings
Political: Medium feasibility. Some advocacy to Region 9 EPA may be needed to implement this option.

IV. Background data and assumptions used

A small amount of information has been received from Region 9 EPA.
Clean Air Mercury Rule making process is in process so newer information may now be available

V. Any uncertainty associated with the option

Medium – responsibility to implement rests primarily with Region 9 EPA.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups TBD

OVERARCHING: AIR DEPOSITION STUDIES

Mitigation Option: Participate in and Support Mercury Studies

I. Description of the mitigation option

Background

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the San Juan Mountains have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness, a Federal Class I Area.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)[2]. Results show mercury concentrations among the highest in the nation. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS[3] and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for McPhee, Narraguinnep, Navajo, Sanchez and Vallecito Reservoirs[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these waterbodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. Mercury amounts and concentrations in wet deposition at Mesa Verde National Park are not likely to portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of waterbodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. In 2007, the Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Option 1: Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

Option 2: Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

Option 3: Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., recommendations 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgibin/asap.cgi/esthag/asap/html/es060377q.html[9]). This study would build on the pilot study planned for Vallecito Reservoir. Costs TBD.

Option 4: Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Option 5: Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Option 6: Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

II. Description of how to implement

See above. Studies would utilize the existing Mercury Deposition Network and expertise developed from past and ongoing studies. Investigators could include scientists from academia, non-profit, private and government organizations and agencies.

III. Feasibility of the Option

Technical -Very feasible; all technology exists or is in development for the above options.

Environmental – Very feasible. Harmful effects on the environment are negligible and permits for sample collection should be easy to obtain.

Financial – Uncertain. It is likely that a consortium of funding entities collaborate for these options. Potential partners include States, industry, US-EPA, USDA-Forest Service, US-Department of Energy, and local governments, watershed groups and public health organizations.

IV. Background data and assumptions used See introduction section

V. Any uncertainty associated with the option Funding uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups Energy and Monitoring Groups

Citations:

[1] See http://www.epa.gov/mercury/about.htm.

[2] National Atmospheric Deposition Program (NADP). Mercury Deposition Network http://nadp.sws.uiuc.edu/mdn/. National Trends Network. http://nadp.sws.uiuc.edu/.

[3] Campbell, D, G Ingersoll, A Mast and 7 Others. Atmospheric deposition and fate of mercury in high-altitude watersheds in western North America. Presentation at the Western Mercury Workshop. Denver, CO. April 21, 2003.

[4] Colorado Department of Public Health and Environment website: http://www.cdphe.state.co.us/wq/FishCon/FishCon.htm and http://www.cdphe.state.co.us/wq/monitoring/monitoring.html.

[5] Gray, JE, DL Fey, CW Holmes, BK Lasorsa. 2005. Historical deposition and fluxes of mercury in Narraquinnep Reservoir, southwestern Colorado, USA. Applied Geochemistry 20: 207-220.

[6] Colorado Department of Public Health (CDPHE). 2003. Total Maximum Daily Load for Mercury in McPhee and Narraguinnep Reservoirs, Colorado: Phase I. Water Quality Control Division. Denver, CO. http://www.epa.gov/waters/tmdldocs/Mcphee-NarraguinnepTMDLfinaldec.pdf.

[7] Schindler, D. 1999. From acid rain to toxic snow. Ambio 28: 350-355

[8] See http://www.mountainstudies.org/Research/airQuality.htm.

[9] See http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html

OVERARCHING: GREENHOUSE GAS MITIGATION

Mitigation Option: CO_2 Capture and Storage Plan Development by Four Corners Area Power Plants

I. Description of the mitigation option

Carbon sequestration refers to the provision of long-term storage of carbon in the terrestrial biosphere, underground, or the oceans so that the buildup of carbon dioxide (the principal greenhouse gas) concentration in the atmosphere will reduce or slow. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are developed to dispose of carbon.

Emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to over twenty five billion tons worldwide today (1). The additional CO_2, a major contributor to Greenhouse gases, contribute to the phenomenon of global warming and could cause unwelcome shifts in regional climates (1).

The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an approximate additional 11,000,000 Tons of CO_2 per year.

Facilities in the Four Corners area should begin developing carbon sequestration plans to mitigate this important global issue. Four Corners area power plants should research & develop way to reduce their CO_2 emissions.

Benefits: CO_2 emissions reductions would reduce the Greenhouse Gases output of the 4Corners area. Carbon sequestration would slow the buildup of CO_2 emissions in the atmosphere. It would be a regional action to reducing the trends of global warming. Benefits would be environmental and economic. CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the 4C area

Tradeoffs: no tradeoffs

Burdens:
The benefits of protecting the climate will be realized globally and far in the future; the cost of each GHG emissions reduction project is local and immediate.

Cost to power plants, administrative costs.

Sequestration, isolating the CO_2 emissions is cheap; however, capturing/storing is expensive.

II. Description of how to implement

A. Mandatory or voluntary
Combination of mandatory and voluntary
Voluntary: 4C area power plants should begin developing Carbon Sequestration Plans
Mandatory limits or allocations may be set by State and Federal regulators in the near future.

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators can allocate Carbon budgets which will lead to more controls
Appropriate State/Federal agencies to help assess Carbon potential storage areas as part of planning process

III. Feasibility of the option

A. Technical: Technologies exist; many are in R&D phase.
B. Environmental: Capturing and storing CO_2 emissions is difficult.
C. Economic: Capturing CO_2 emissions is expensive.
D. Legal: Liability of CO_2 storage process

IV. Background data and assumptions used

1. Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE
2. CO2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10)
3. San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
4. US DOE Carbon Sequestration Regional Partnerships:
http://www.fossil.energy.gov/programs/sequestration/index.html
New Mexico Partnerships
http://www.fossil.energy.gov/programs/projectdatabase/stateprofiles/2004/New_Mexico.html

V. Any uncertainty associated with the option

Medium.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

CO_2 emissions reduction Cross-over issue with other energy industries such as Oil & Gas. Oil & Gas industries could also be held responsible for developing Carbon sequestration plans.

CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the Four Corners area.

Mitigation Option: Climate Change Advisory Group (CCAG) Energy Supply Technical Work Group Policy Option Implementation in Four Corners Area

I. Description of the mitigation option
The New Mexico Climate Change Advisory Group (CCAG) is a diverse group of stakeholders from across New Mexico. At the end of 2006, the group will put forth policy options for reducing greenhouse gas emissions in NM to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. 69 recommendations covering transportation, land use, energy supply, agriculture and forestry were made which if implemented would exceed emissions reduction target for 2020.

A GHG emissions inventory for New Mexico prepared by The Center for Climate Strategies (2) showed electricity generation to comprise 40% of the states GHG emissions. The electricity generation sector is a source contributor of GHG and there are many areas for potential reductions. In the future, if the proposed Desert Rock Energy Project comes online, the additional 11 million tons of CO2 from Desert Rock would increase the electricity generation portion of New Mexico GHG emissions to approximately 50%.

The energy supply technical work group drafted options for renewable portfolio standards and advanced coal technologies (1). These policy options should be applied to Four Corners area facilities. The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an additional estimated 11,000,000 Tons of CO_2 per year (3).

Local State/Federal Regulating agencies should work with the existing and proposed power plants to collaborate to help realize the targets of the Climate Change Advisory Group. CO_2 sequestration technologies and other Greenhouse gas mitigation strategies should be assessed and implemented to meet the targets.

Benefits:
Environmental: reduction of greenhouse gas emissions to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. Mitigation of adverse climate change effects

Net economic savings for the state's economy

Tradeoffs: none
Burdens: Cost to existing and proposed power pants and administrators

II. Description of how to implement
A. Mandatory or voluntary
Combination of mandatory and voluntary

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators:
Oil Conservation Division (NMOCD)
New Mexico Air Quality Bureau
New Mexico Energy, Minerals, and Natural Resources Division

Other Four Corner State Environmental Protection Agencies

III. Feasibility of the option
A. Technical: TBD

B. Environmental: TBD
C. Economic: TBD

IV. Background data and assumptions used

(1) New Mexico Climate Change Advisory Group (CCAG): http://www.nmclimatechange.us/
(2) Draft New Mexico Greenhouse Gas Inventory and Reference Case Projections, The Center for Climate Strategies, July 2005
(3) CO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
(4) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(5) Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Greenhouse Gas (GHG) emissions reduction Cross-over issue with other energy industries such as Oil & Gas.

OVERARCHING: CAP AND TRADE

Mitigation Option: Declining Cap and Trade Program for NO_x Emissions for Existing and Proposed Power Plants

I. Description of the mitigation option

Cap and trade is a policy approach to controlling large amounts of emissions from a group of sources at costs that are lower than if sources were regulated individually. The approach first sets an overall cap, or maximum amount of emissions per compliance period, that will achieve the desired environmental effects. Authorizations to emit in the form of emission allowances are then allocated to affected sources, and the total number of allowances cannot exceed the cap.

Individual control requirements are not specified for sources. The only requirements are that sources completely and accurately measure and report all emissions and then turn in the same number of allowances as emissions at the end of the compliance period.

For example, in the Acid Rain Program, sulfur dioxide (SO_2) emissions were 17.5 million tons in 1980 from electric utilities in the U.S. Beginning in 1995, annual caps were set that decline to a level of 8.95 million allowances by the year 2010 (one allowance permits a source to emit one ton of SO_2). At the end of each year, EPA reduces the allowances held by each source by the amount of that source's emissions (1, EPA Clean Air Markets).

A declining cap and trade program means that the cap would be slightly lowered over time to reduce the total NOx emissions in the Four Corners area. A declining cap and trade program would be effective for the Four Corner areas' electric generating units.

The power plants in the area have continuous emissions monitors. We can measure accurately each plant's NOx emissions. In 2005 the NO_x emissions from San Juan Generating Station were 27,000 tons. The Four Corners Power Plant emitted 42,000 tons (2). Desert Rock Energy facility would add an approximate 3,500 tons/yr (2). NO_x emissions from electricity generating units (EGUs) will continue to be reported and recorded under the EPA Acid Rain Program (3). So the data is available. For each of these facilities the costs for additional controls and NO_x emissions reductions is different.

Electric Generating Units (EGUs) will be defined as it is EPA's Clean Air Interstate Rule:

(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

The program will cover all EGUs.

The Four Corners area declining cap and trade program would cap NO_x levels from EGUs at current levels. The cap could be lowered 5% every 10 years or a collaboratively agreed on level.

The Declining cap and trade program would include all EGUs in the Four Corners area, and could also possible be extended to oil & gas sources. New sources could obtain offsets.

There should be some discussion regarding how the cap would be set; as well as how to protect against hot spots.

Benefits: The cap will prevent NO_x emissions from the Four Corners area sources from increasing. Regardless of new power plants, sources will have to find a way to keep overall NO_x emissions below the declining cap.

The program will reduce NO_x emissions in the Four Corners area.
Power Plants would continue to look at new ways to reduce emissions.

Differing Opinion: Cap and trade is a band aid approach to reduction of emissions. It may look good on paper, but does nothing to enhance the air quality. Cap and trade should not be an option for power plant or oil and gas emissions in the Four Corners Area. Extensive improvement of the air quality and consideration for the health and welfare of the people and the environment should be the top priority.

Tradeoffs: None

Differing Opinion: The trade off of cap and trade is that the numbers look good, but in reality, the emissions are still in existence.

Burdens:
Regulatory agency needs to be able to collect, verify all emissions information and be able to enforce rule

II. Description of how to implement

A. Mandatory or voluntary
Mandatory

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NO_x emissions are measured using CEMS by large Power Plants. Complete and verified emissions measurements are reported by the Four Corners area power plants and is available on the EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

B. Environmental: NO_x control technologies are available.
C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low. Cost savings are significant because regulators do not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. Regulators do not need to review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (1). Power Plants may need retrofits or to buy or sell credits.

* Cumulative Effects Work Group: How would a 5% declining cap and trade program for NO_x in the Four Corners area affect visibility and ozone levels?

IV. Background data and assumptions used

1. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html

A cap and trade program also is being used to control SO_2 and nitrogen oxides (NO_x) in the Los Angeles, California area. The Regional Clean Air Incentives Market (RECLAIM) program began in 1994. [1]

2. NO_2 emissions from Four Corners area power plants
(4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
*NO_x emissions from existing power plants obtained from EPA Acid Rain database
*NO_x emissions from proposed Desert Rock Energy Facility from AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

3. EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

<u>V. Any uncertainty associated with the option</u> Low.

<u>VI. Level of agreement within the work group for this mitigation option</u> To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Declining Cap and Trade program would cross-over with Oil & Gas work group.

Mitigation Option: Four Corners States to join the Clean Air Interstate Rule (CAIR) Program

I. Description of the mitigation option

EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. It is expected that this rule will result in the deepest cuts in sulfur dioxide (SO_2) and nitrogen oxides (NOx) in more that a decade (1).

The Clean Air Interstate Rule establishes a cap-and-trade system for SO_2 and NO_x based on EPA's proven Acid Rain Program. The Acid Rain Program has produced remarkable and demonstrable results, reducing SO_2 emissions faster and cheaper than anticipated, and resulting in wide-ranging environmental improvements. EPA already allocated emission "allowances" for SO2 to sources subject to the Acid Rain Program. These allowances will be used in the CAIR model SO2 trading program. For the model NOx trading programs, EPA will provide emission "allowances" for NOx to each state, according to the state budget. The states will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions. Because each source must hold sufficient allowances to cover its emissions each year, the limited number of allowances available ensures required reductions are achieved. The mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained. The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

While most of the states are in the Eastern half of the US, Texas is participating in the CAIR program. Four Corners states could also participate and realize the emissions reduction benefits of CAIR.

SO_2 and NO_x contribute to the formation of fine particles and NO_x contributes to the formation of ground-level ozone. Fine particles and ozone are associated with thousands of premature deaths and illnesses each year. Additionally, these pollutants reduce visibility and damage sensitive ecosystems (1).

By the year 2015, the Clean Air Interstate Rule will result in (Eastern US benefits) (1):
-- $85 to $100 billion in annual health benefits, annually preventing 17,000 premature deaths, millions of lost work and school days, and tens of thousands of non-fatal heart attacks and hospital admissions.
-- nearly $2 billion in annual visibility benefits in southeastern national parks, such as Great Smoky and Shenandoah.
-- significant regional reductions in sulfur and nitrogen deposition, reducing the number of acidic lakes and streams in the eastern U.S.

Based on an assessment of the emissions contributing to interstate transport of air pollution and available control measures, EPA has determined that achieving required reductions in the identified states by controlling emissions from power plants is highly cost effective (1).

States must achieve the required emission reductions using one of two compliance options: 1) meet the state’s emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an individual state emissions budget through measures of the state’s choosing (1).

CAIR provides a Federal framework requiring states to reduce emissions of SO_2 and NO_x. EPA anticipates that states will achieve this primarily by reducing emissions from the power generation sector.

These reductions will be substantial and cost-effective, so in many areas, the reductions are large enough to meet the air quality standards.

The Clean Air Act requires that states meet the new national, health-based air quality standards for ozone and PM2.5 standards by requiring reductions from many types of sources. Some areas may need to take additional local actions. CAIR reductions will lessen the need for additional local controls (1).

This final rule provides cleaner air while allowing for continued economic growth. By enabling states to address air pollutants from power plants in a cost effective fashion, this rule will protect public health and the environment without interfering with the steady flow of affordable energy for American consumers and businesses.

CAIR Timeline:
Promulgate CAIR Rule 2005, State implementation Plans Due 2006, Phase I Cap in Place for NOX, Phase I Cap in Place for SO2, Phase II Cap in Place for NOx and SO_2 (1). Caps will be fully met in 2015 to 2020, depending on banking.

The Four Corners area has existing and proposed power plants with significant NO_x and SO_2 emissions. The problem occurs over a relatively large area, there are a significant number of sources responsible for the problem, the cost of controls varies from source to source, and emissions can be consistently and accurately measured. Cap and Trade programs typically work better over broader areas. The Four Corners area as well as each state would realize a more successful Cap and Trade program from being a part of a large interstate program such as CAIR.

By joining the EPA CAIR program, the 4 Corner states of New Mexico, Colorado, Arizona, and Utah will also benefit from the interstate SO_2 and NOx emissions reductions.

Need some discussion on how to set cap, and protect against hot spots.

Benefits:
"If states choose to meet their emissions reductions requirements by controlling power plant emissions through an interstate cap and trade program, EPA's modeling shows that (for eastern states):

- In 2010, CAIR will reduce SO_2 emissions by 4.3 million tons -- 45% lower than 2003 levels, across states covered by the rule. By 2015, CAIR will reduce SO2 emissions by 5.4 million tons, or 57%, from 2003 levels in these states. At full implementation, CAIR will reduce power plant SO_2 emissions in affected states to just 2.5 million tons, 73% below 2003 emissions levels.
- CAIR also will achieve significant NOx reductions across states covered by the rule. In 2009, CAIR will reduce NOx emissions by 1.7 million tons or 53% from 2003 levels. In 2015, CAIR will reduce power plant NOx emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61% reduction from 2003 levels. In 1990, national SO_2 emissions from power plants were 15.7 million tons compared to 3.5 million tons that will be achieved with CAIR. In 1990, national NO_x emissions from power plants were 6.7 million tons, compared to 2.2 million tons that will be achieved with CAIR (1)."

Tradeoffs: None
Burdens: Administrative costs on regulating agencies, including how to determine state or regional level cap; emissions control upgrade costs or purchasing allowances to power plants

II. Description of how to implement

A. Mandatory or voluntary

Mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained (1).

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NOx emissions are measured using CEMS by large Power Plants. Complete and consistent emissions measurement and reporting by all sources guarantees that total emissions do not exceed the cap and that individual sources' emissions are no higher than their allowances

B. Environmental: NO_x, SO_2 control technologies are available.

C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low (2).

Cost savings are significant because EPA does not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. EPA does not review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (2).

The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

IV. Background data and assumptions used

1. EPA Clean Air Interstate Rule: http://www.epa.gov/cair/
2. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html
3. "EPA Enacts Long-Awaited Rule To Improve Air Quality, Health" Rick Weiss, Washington Post, Friday, March 11, 2005; Page A01 http://www.washingtonpost.com/wp-dyn/articles/A23554-2005Mar10.html
4. The White House – Council on Environmental Quality, Cleaner Air,
http://www.whitehouse.gov/ceq/clean-air.html

V. Any uncertainty associated with the option

Low – Program is based on a proven cap and trade approach
Need mechanism to be assured that a significant portion of actual reductions are achieved in the Four Corners area to assure the environmental benefit.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

Clean Air Interstate Rule would cross-over with Oil & Gas work group

OVERARCHING: ASTHMA STUDIES

Mitigation Option: Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

I. Description of the mitigation option

This option would involve conducting a chronic respiratory disease study for the Four Corners area to determine the relationship between air pollutants from power plants and respiratory health effects. On going studies are necessary to continue to evaluate health risks associated with the large number of combustion emission sources in the area, primarily the two large coal-fired power plants in the area. Cumulatively, the two largest power plants in the area emit approx 66,000 tons/yr of nitrogen oxides (1). Nitrogen oxides are key precursor emissions to ozone.

Background

The NM Department of Health conducted a pilot project that linked daily maximum 8-hour ozone levels with the number of asthma-related emergency room visits at San Juan Regional Medical Center located in northwestern NM. The ozone and ER asthma data were collected for the period of 2000 - 2003. The number of emergency room visits in the summer increased 17% for every 10 ppb increase in ozone levels. This relationship occurred particularly following a two day lag and was statistically significant. These results are in general agreement with studies in other states and provide a foundation for tracking asthma-ozone relationships over time and space in NM (2).

The New Mexico Environment Department Air Quality Bureau operates and maintains three continuous ozone monitors in San Juan County. The eight-hour ozone design value in San Juan County has been maintained below the National Ambient Air Quality Standard for ozone of 0.08 ppm. The final eight-hour ozone design value for 2005 for San Juan County (San Juan Substation and Bloomfield monitors) was 0.072 ppm. The 2006 eight-hour ozone design value for San Juan County Substation monitor was 0.071 ppm. The 2006 eight-hour ozone design value for the San Juan County Bloomfield monitor was 0.069 ppm.

The Colorado Department of Public Health and Environment (CDPHE) has also researched asthma and links to environmental conditions. In a recent paper, "Holistic Approaches for Reducing Environmental Impacts on Asthma", CDPHE, discusses staff researcher's efforts to bring clarity to any identifiable linkage between environmental conditions and asthma. CDPHE investigated asthma rates throughout the state and compared these data against known and anecdotally reported information. Findings indicate that regions of Colorado do appear to have a higher incidence of asthma rates. In addition, some of the identified regions were not previously anticipated (e.g., rural communities), highlighting the need for further investigations (4).

The study describes asthma as a serious, chronic condition that affects over 15 million people in the United States. Asthma is a disease characterized by lung inflammation and hypersensitivity to certain environmental "triggers" such as pollen, dust, humidity, temperature and various environmental pollutants (dust, ozone, etc.), among others. Colorado has a particular problem with the occurrence of this condition, but the reasons for this are not well understood. Statewide there are an estimated 283,000 people with asthma, a figure that well exceeds national expectations. (4).

The CO-benefits risk assessment (COBRA) model is a recently developed screening tool that provides preliminary estimates of the impact of air pollution emission changes on ambient particulate matter (PM) air pollution concentrations, translates this into health effect impacts, and then monetizes these impacts

(5). A model such as this could be expanded to include other forms of air pollution such as ozone and be customized for the Four Corners Area.

Overarching modeling results should be cross-checked with local hospital inventory results and compared with other locations in the United States.

Benefits: Study would allow Four Corner area planning agencies to make better decisions and give the public a better idea of risk assessments

Tradeoffs: None

Burdens: Resources needed to conduct study

II. Description of how to implement

A. Mandatory or voluntary
Conduct coordinated outreach to obtain grant funding for the study.
(Study to be conducted by the end of 2009, with model development for assessing situation annually)

B. Indicate the most appropriate agency(ies) to implement
The states, the Environmental Protection Agency (EPA), and American Lung Association collaboration.

The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.

III. Feasibility of the option (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

Technical: The state and federal health organizations should be able to develop a 4C area model to assess the relationship between air pollutants from power plants and respiratory health effects

Environmental: Need for further modeling of Four Corners area customized to assessing respiratory health effect relationship to air pollutants from power plants. Existing COBRA model may be used as a starting point.

Economic: Grant funding would be required

*Monitoring work group: Assess whether or not we have the adequate data from monitoring stations to assess asthma situation. VOC and NOx emissions are contributors to ozone. Do we have good VOC data in the 4C area?

*Cumulative Effects work group: Assess the ozone trends in the 4C area. On average are ozone levels increasing or decreasing? Where are locations in the Four Corners area with the highest ozone concentrations? What are the relative contributions from power plants compared to oil and gas & other sources?

IV. Background data and assumptions used

(1) EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)
(2) New Mexico Department of Health Ozone Study
(3) New Mexico Environment Department – Ambient Ozone Level Data

(4) Holistic Approaches for Reducing Environmental Impacts on Asthma, Paper # 362, Prepared by Mark J. McMillan, Mark Egbert, and Arthur McFarlane, Colorado Department of Public Health and Environment.
(5) User's Manual for the CO-Benefits Risk Assessment (COBRA) Screening Model, US EPA, June 2006

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups Oil and Gas and Other Sources Work Groups

OVERARCHING: CROSSOVER

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. The electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.

According to projections, at least 12,500 new gas wells will be drilled in the San Juan Basin over the next 20 years. It is said that this gas field is loosing pressure and compression on thousands of wells is necessary. Pollution emissions from production engines are rapidly increasing. To date, there is no cumulative emissions measurement.
Using BLM figures, an average gas powered wellhead compressor at 353,685 hp-hr per year at 13.15g per hp-hr = 4,650,957 g/year of NO_x. This is just an example of NO_x emissions. This figure does not account for other compounds in exhaust emissions such as VOCs, carbon monoxide, etc. This is equivalent to a 17 car motorcade running non-stop, circling your house 24 hours per day.

Gas powered wellhead compressors and pumpjacks are being installed in close proximity to inhabited homes and institutions. The City of Aztec required electric compressors, although that ordinance was not enforced, on wellhead engines within the city limits prior to 2004 when the ordinance was revised. Electric engines were required in order to protect citizens from noxious emissions from gas fired engines near homes. Electric engines are thought to be quieter than gas fired engines; therefore reducing noise pollution also.

Gas fired engines are being installed on wells in close proximity to existing electric lines. Electric engines should be required on all sites near power lines especially near homes. In areas where there is no electricity, best available technology must be implemented such as 2g/hp/hr engines, catalytic converters, etc.

Air Quality/Environmental

- Elimination of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities).

Economics

- The costs to replace natural gas fired compressors with electric motors would be costly.
- The costs of getting electrical power to the sites would be costly. It could require a grid pattern upgrade which could costs millions of dollars for a given area.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

*A cumulative emissions inventory on all oil and gas field equipment is necessary
*If possible, a calculation of pollution related to electric power generation is needed for comparison to pollution emitted from gas powered engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

Oil and Gas Work Group
Cumulative Effects Work Group
Power Plant Work Group

OVERARCHING: CROSSOVER OPTIONS

Mitigation Option: Economic-Incentives Based Emission Trading System (EBETS) (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

FOUR CORNERS AREA POWER PLANTS FACILITY DATA TABLE

This data table was prepared by the Power Plants Work Group as a resource to help develop mitigation options. Facility data information was compiled from a variety of sources (see references). The last update of the table was August 2007. The Table, along with other resource information on Four Corners area power plants, is also available on the Task Force Website on the Power Plants Work Group Page, http://www.nmenv.state.nm.us/aqb/4C/powerplant_workgroup.html

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010 [10]
San Juan Generating Station [1]	PNM Resources (Owner/Operator)	Coal	ARP, EPA 9, Western Systems Coordinating Council	NMED - AQB	4 units, 1798 MW	PM- ESP	PM – 673 tons (2005)		PM – baghouse	13,097,406 tons (2005)	PM - 670 tons/yr
						SO_x - Wet Limestone	SO_2 – 16,570 tons (2005)	SO_2 – 16,179.3 tons (2004), 16,569.5 tons (2005) [4]	SO2 – enhanced scrubbing		SO2 - 8,900 tons/yr
						NO_x – Low-NOx burners / Over-fired air	NO_x – 26,809 tons (2005)	NO_x – 26,880.2 tons (2004), 26,809.0 tons (2005) [4]	NO_x – low-NO_x burners/ over-fired air / neural net		NOx - 18,500 tons/yr
						Hg – Wet scrubber	Hg – 766 lbs (2005)	CO_2 – 13,147,181.0 tons (2004), 13,097,410.1 tons (2005) [4]	Hg – activated carbon. Hg – CEMs		Hg - 275 lbs/yr
Four Corners Power Plant [2,3]	Arizona Public Service Company (Owner/Operator)	Coal	ARP, EPA 9	EPA Region 9, Navajo Nation EPA	5 units, 2040 MW	Units #1 - #3:	PM – 1,187 tons (2000-2005 annual average)		Considering available technologies for future regulatory changes [3]	15,913,105 tons (2000-2005 annual average)	N/A
						PM - Wet venturi scrubbers	SO_2 – 12,500 tons (2005)	SO_2 – 18,771 tons (2004), 12,554.2 (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO$_2$)	Estimated Emissions after upgrades 2010
Four Corners Power Plant [2,3] (cont.)						SOx - Dolomitic lime wet scrubbing	NO$_x$ – 42,000 tons (2000-2005)	NO$_x$ – 40,742 tons (2004), 41,743.4 tons (2005)			N/A
						NO$_x$ – Low-NOx burners	Hg – Approx. 550-600 lbs/yr	CO$_2$ – 15,106,255 tons (2004), 16,015,408.7 tons (2005) [4]			
						Hg – Venturi scrubber					
						Units #4 & #5:					
						PM – Baghouses					
						SOx – Lime slurry wet scrubbing					
						NOx – Low-NOx burners					
						Hg – Wet scrubber, baghouses					
Proposed Desert Rock Energy Facility [5, 12]	Sithe Global Power, LLC (proposed owner/operator)	Coal		EPA Region 9, Navajo Nation EPA	2 units, 1500 MW [5]	PM – Baghouse [6, 12][1]	PM (TSP/PM) – 570 Tons/yr [6,12][3]		Hg – activated carbon if control < 90% and cost < $13,000/lb**	Approx. 12,700,000 tons/yr[8]	N/A
							PM$_{10}$ – 1,120 Tons/yr [6, 12][4]				
						SOx –Wet Limestone FGD [6, 12][1]	SO$_2$ – 3,319 Tons/yr [6, 12]				
						NOx – low-NOx burners/ over-fired air / SCR [6,12]	NO$_x$ – 3,325 Tons/yr [6, 12]				

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO$_2$)	Estimated Emissions after upgrades 2010
Proposed Desert Rock Energy Facility [5, 12] (cont.)						Hg – SCR +baghouse +FGD[2] [6, 12]	Mercury – 114 lbs/ yr [12]				N/A
							CO – 5,529 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	Lead – 11.1 Tons/yr [12] Flourides – 13.3 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	H_2SO_4 – 221 Tons/yr [12]				
Bluffview Power Plant [4]	City of Farmington (Owner/Operator) (Started 28-JUL-05)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		60 MW	Dry Low NOx Burners, Selective Catalytic Reduction		SO_2 – 0.7 tons/yr (2005) [4]		145997.3 tons (2005) [4]	N/A
								NO_x – 58.5 tons/yr (2005) [4]			
Milagro [4]	Williams Field Services (Owner/Operator)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		2 units, 61 MW [11]			SO_2 – 2.6 tons (2004), 2.5 tons (2005) [4]		498823.3 tons (2005) [4]	N/A
						NO_x – Dry Low-NOx burners		NO_x – 97.6 tons (2004), 110.2 tons (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Animas Power Plant [9]	City of Farmington (Owner/Operator)	Pipeline Natural Gas / Cogeneration	EPA 6, Western Systems Coordinating Council		51 MW [9]		SO2 – 0 (2005, turbine only)				N/A
							NOx – 54 Tons (2005, turbine)				
							VOC – 54.3 Tons (2005, turbine)				
							CO – 5.1 Tons (2005, turbine)				
Bloomfield Generation [4]	Ameramex Energy Group, Inc. (Owner/Operator)		ARP, EPA 6								N/A
Navajo Dam Hydro Plant [9]	City of Farmington (Owner/Operator)	Water			30 MW [9]						N/A
Mustang Energy Project[7][5]	Proposed	Coal			300 MW		PM - 185 tons/yr			Approx. 2,000,000 tons/yr[8]	N/A
							SO_2 – 250 tons/yr				
							NO_X - 125 tons/yr				

[1] May 23, 2006 edit, info provided by Mike Farley (PNM), and in SJGS presentation for 4CAQTF, "SJGS Emissions Control Current and Future" http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf
[2] http://www.aps.com/general_info/AboutAPS_18.html [dl 5/29/06]
[3] APS Four Corners Power Plant tour handout (received 5/10/06), supplemental info provided by Richard Grimes (APS), in May 31 table edit
[4] EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)

[5] SITHE GLOBAL Desert Rock Energy Project FACT SHEET #1 DEC 2004 [dl 5/29/06]
[6] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, prepared by ENSR International May 2004
[7] Reference to Dave R. edits 6/2/06
[8] Desert Rock Energy Project Draft EIS Ch. 4.0 – Environmental Consequences May 2007
[9] Farmington Electric Utility Fact Sheet http://206.206.77.3/pdf/electric_utility/feus_fact_sheet.pdf (6/16/06) / NMED
[10] Info provided by Mike Farley (PNM)
[11] http://www.emnrd.state.nm.us/EMNRD/MAIN/documents/SER1_electricity.pdf
[12] AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01), Table 1, EPA Region 9 Air Programs: http://www.epa.gov/region09/air/permit/desertrock/#permit

[1] Subject to BACT - Best available control technology [6]
[2] Mercury (Hg) and HCL have been targeted under future regulation under maximum available control technology (MACT) [6]
[3] PM is defined as filterable particulate matter as measured by EPA Method 5.
[4] PM10 is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM10 as a surrogate for PM2.5.
[5] Outside of Scope of Work, Not located in 4CAQTF study area

POWER PLANTS: PUBLIC COMMENTS

Power Plants Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It saddens me and concerns me for our children's futures and the native American leaders who think that this is progress and prosperity for their people. The leaders are once again selling out their people for the promise of temporary jobs and profits. How can we as a educated people agree to allow this plant in today's environment? Mercury in our children's blood and more carbons in the air are a horrible price to pay for short term gains in energy downstream. How can Governor Richards speak of the environment while he is silent on this issue. I will not be able to attend any public meetings and would appreciate my view forwarded if possible. I am a mother, grandmother and previous medical office manager. Most importantly, I am a voter.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment

Comment	Mitigation Option
Desert Rock Energy LLC (Desert Rock) appreciates the opportunity to submit the following comments on the Four Corners Air Quality Task Force Draft Report. Desert Rock supports the Task Force's efforts to promote air quality mitigation in the Four Corners area. Desert Rock is committed to air quality mitigation, and has designed the proposed Desert Rock Facility to minimize impacts while providing needed electricity and additional economic development to the Navajo Nation. As detailed in the Draft Task Force Report, the proposed Desert Rock Facility is a 1,500 MW mine mouth power plant being developed by Sithe Global Power, Desert Rock Energy Company, and the Dinè Power Authority (an enterprise of the Navajo Nation). It is designed to burn low BTU, low sulfur subituminous Navajo coal. The plant will be located at an elevation of 5,415 feet. It will be one of the most efficient plants in the US, with two supercritical pulverized coal-fired boilers operating at a net heat rate of 8,983 Btu/kWh. The plant will be required to operate with very low emission rates, including 0.06 lb/MMBtu for both NOx and SO2 and 0.01 lb/MMBtu for filterable PM, all on a 24-hour average. The plant will also use dry cooling to reduce water consumption by 80 percent. EPA has stated that the Desert Rock Facility will have the lowest emission rates of any coal-fired project in the US. These emission rates will be even lower than emission rates associated with IGCC. Desert Rock is committed to engaging in regional air quality improvement initiatives. In fact, Desert Rock has already invested significant time and resources participating in such initiatives. Desert Rock has worked with the National Park Service, the National Forest Service, EPA, the Navajo National Environmental Protection Agency, and other governmental stakeholders to create a mitigation plan that will offset all SO2 emissions from the facility and further reduce mercury impacts. Below is a description of this regional effort: 1. Desert Rock Energy has agreed to a Voluntary Regional Air Quality Improvement Plan with the US EPA, US Forest Service, National Parks Service, and the Navajo Nation Environmental Protection Agency. 2. The Improvement Plan requires Desert Rock to reduce regional SO2 emission and visibility impacts by one of three (3) mechanisms: 1) Regional SO2 Control, 2) Regional NOx Control, or 3) Procurement and retirement of SO2 Allowances. a. Under an SO2 control-sponsored project, the implementation of this plan will result in a net improvement of the local environment. The plan, not only will totally offset the SO2 emissions of Desert Rock (3,315 tons of SO2), it will also remove an additional 330 tons of SO2 from the local atmosphere, for a total reduction of 110%. b. If an SO2 control project cannot be developed, Desert Rock may implement a NOx control-sponsored project which will remove NOx emissions in the region by 100% of Desert Rock NOx emissions plus approximately an additional 7500 tons. c. If Desert Rock is not able to invest in capital projects at other plants to reduce SO2 or NOx emissions, Desert Rock has reserved capital to purchase and retire up to $3,000,000 per year in SO2 allowances for the life of the project. The acquisition of these allowances is beyond those that are required under the Acid Rain program.	General Comment

Comment	Mitigation Option
3. Mercury control of at least 80% will be achieved. Additional investments in Mercury control technology to reach a target of 90% control will be made subject to plan limitations. If the 90 % control target is met, it will reduce mercury emissions an additional 50 percent from approximately 160 lbs per year to approximately 80 lbs per year. 4. The local area will benefit from Desert Rock's annual environmental contributions that may be available subject to plan limitations. Such contributions could be used to advance the local environmental science and planning as well as sponsor projects that reduce greenhouse gas emissions, add further mercury control, increase monitoring, support the Four Corners Task Force, or contribute to any other environmental project determined to be of great value to the region. Desert Rock objects to the language in the Draft Report stating that "[t]he uncertainty [about the mitigation plan] involves how stakeholders can be assured the measures will actually happen." Desert Rock has made a public commitment to implement this mitigation plan and, in order to reassure all stakeholders of its commitment, is in the process of working with Federal agencies and the Navajo Nation to ensure that this mitigation plan is federally enforceable. The Desert Rock Facility will therefore be held accountable for fulfilling its mitigation commitments. In light of the mitigation plan, the Draft Report is incorrect in saying that "[w]hile the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area." It is quite likely that, because of the mitigation plan, either SO2 or NOx emissions in the area will actually be reduced. Although there will be a very small increase in emissions of other pollutants, the amounts are so small that the Plant will not have an appreciable impact on air quality in the Four Corners area. Discussion of CO2 Emissions Desert Rock believes that global climate change is a very serious issue and is committed to working with governments and industries to develop laws and policies - and most importantly, advanced technologies - that will reduce anthropogenic emissions of CO2 and other greenhouse gases. Indeed, as discussed below, we are actively exploring options that may allow us to capture and sequester CO2 emissions from the plant at some point in the future. We are concerned, however, about the discussion of CO2 emissions in the Draft Report. The Report is designed to address air quality issues in the Four Corners area, and it is simply misleading to suggest that CO2 is an air quality issue. CO2 emissions in New York and New Delhi will have precisely the same impact on climate change in the Four Corners Region as CO2 emissions from Desert Rock. By addressing CO2 without making a clear distinction between air quality (which is largely a local and regional issue) and climate change (which is entirely a global issue), the Report will actually be misleading to many readers who are not fully informed about the nature of climate change.	

Comment	Mitigation Option
IGCC and Desert Rock The Draft Report includes a discussion of Integrated Gasification Combined Cycle (IGCC) technology that is not appropriate for the Desert Rock Facility. We are concerned that it will mislead readers into thinking that IGCC would be a better environmental choice for the Four Corners area, when this is simply not the case. The EPA Report cited in the Report does not address the issues involved in building an IGCC plant (or a modern supercritical pulverized coal plant) with the type of coal available in the Four Corners area or at an altitude anywhere near the elevation of the Desert Rock Facility. Not only technical experts with Desert Rock Energy, but other technical experts have concluded that there would be serious technical challenges involved in trying to operate an IGCC plant at a site like the Desert Rock Facility. The Report suggests that, at a minimum, Desert Rock should have been required to evaluate IGCC as part of the BACT process. Desert Rock did, in fact, evaluate the potential use of a range of modern coal technologies including IGCC. Nothing more would be learned by formally including such an evaluation in the BACT process. Desert Rock determined that the use of modern supercritical pulverized coal boilers is the best option, not only in terms of cost and reliability, but from an environmental standpoint as well. This technology is proven, reliable, and highly efficient and, in combination with an extensive array of pollution control equipment, will be a leader in reducing emissions from coal combustion. EPA has again stated that the Desert Rock Facility will have the lowest emissions rate of any coal-fired project in the US. As discussed below, there would be no material difference in emissions - including CO2 and other green house gas emissions - with an IGCC plant at the Desert Rock site assuming current IGCC technology performance. Though IGCC is an evolving technology, IGCC does not currently meet the need for reliable and economical power production. There are only four operating coal-fired IGCC plants in the world, two in the United States both which use petroleum coke and not coal as the fuel source. Other IGCC projects in the US were built as small scale (less than 300 megawatts) demonstration projects with substantial government funding and some faced such severe operating problems that they never reached commercial operation. Even the facilities that did achieve commercial operation have not met projections for cost, efficiency, reliability and environmental performance. The "next generation" of IGCC plants, currently in development, with commercial operation dates planned in the 2011-2015 period, are in the 300-600 megawatt range. It remains to be seen if the next generation of IGCC plants will meet the cost and reliability targets needed to provide reliable, low cost power. There are also many engineering issues that remain to be solved in using low BTU high ash coals such as those found in New Mexico to fuel IGCC plants. Reliability - The IGCC units currently in operation have a poor reliability records. It remains to be seen if the next generation of IGCC plants will face similar reliability issues. The "integrated" part of IGCC refers to the integration of a gasifier and a combined cycle power plant to transform the	

Comment	Mitigation Option
coal into syngas and combust that syngas to produce electricity. This integration introduces numerous additional potential engineering points of failure and, as a result, there is a record of poor performance. Several of the IGCC units in operation have been able to reach the 80% reliability level but only after five to ten years of operation. In contrast, supercritical technology proposed for Desert Rock has a proven performance record of 90% or better, beginning in its first year of operation. Cost - Projections of life cycle capital and operating costs for IGCC plants in the 600 to 2,000 megawatt range are substantially higher than supercritical technology. These have demonstrated that the cost of a 1,500 megawatt IGCC plant is approximately 30-40% higher than a similarly-sized supercritical pulverized coal plant. Desert Rock would cost $1 billion more built using IGCC technology. Efficiency - The technology proposed for the Desert Rock Facility is highly efficient, meaning substantially less coal is used to produce the same amount of electricity with fewer emissions than older, conventional coal fired power plants. Desert Rock's proposed technology is also more efficient than current IGCC plants. For example, the technology proposed for the Desert Rock Facility is approximately 15% more efficient than the present IGCC facilities in Florida and Indiana, meaning it will use 15% less coal to produce a similar amount of electricity on an average annual basis. In comparison to recently filed air permit applications for the "next generation" IGCC plants, the Desert Rock Facility will have comparable efficiencies when the IGCC efficiency losses of operating at above 5,000 ft above sea level are taken in account. Emissions - Due to the high efficiency of the Desert Rock Facility's generating technology and the extensive array of pollution control equipment incorporated into its design, the plant's emission rates compare very favorably to existing IGCC units and are expected to be similar to the "next generation" IGCC plants. IGCC plants do not produce any less greenhouse gasses than a supercritical plant with similar efficiency Desert Rock is also designing the facility to have "future proofing" characteristics, which allow for augmentation of the initial extensive array of emissions control equipment and with more advanced control equipment when the new equipment is demonstrated to be commercially viable. Summary on IGCC - Desert Rock carefully considered all options available before concluding that supercritical pulverized coal technology is the best choice for the facility. The Desert Rock Facility's supercritical design helps to ensure a reliable power supply and lower fuel cost for customers, while being highly protective of public health and the environment. While IGCC is expected to become a viable large scale electric generation technology in the future, it currently lacks the reliability, efficiency, economics, and scale that supercritical technology provides with no material difference in emissions including greenhouse gases Carbon Sequestration and Desert Rock Sithe Global Power, LLC continues to study the technological and commercial implications of carbon capturing and sequestration (CCS) in	

Comment	Mitigation Option
power plant applications. With respect to the Desert Rock Facility, we have participated in numerous discussions with the Department of Energy, various national laboratories, and the major equipment suppliers to evaluate the technological feasibility and economic viability of a large scale CCS project. After extensive discussions, we have been unable to identify a commercially feasible solution. As of today, the major equipment suppliers are unwilling to offer performance guarantees for a large scale CCS project. In addition, an appropriate mechanism to recover the cost of implementation, including the cost of development, installation and operation, has not yet been implemented. As a result, Desert Rock is not in a position to incorporate CCS at this time. Desert Rock intends to continue to participate in the development of CCS and will consider the implementation of CCS once the technology and commercial framework are in place. The major equipment suppliers have an economic incentive to complete the development of the necessary technology. The Task Force can provide a great deal of assistance to help create and promote an appropriate commercial framework. Thank you for the opportunity to provide the above comments on the Draft Task Force Report. Desert Rock is again committed to air quality mitigation and appreciates the Task Force's efforts. If you have any questions or we can be of assistance, please let us know. Sincerely, Dirk Straussfeld Executive Vice President Desert Rock Energy Company, LLC Three Riverway Suite 1100 Houston, Texas 77056 Phone: (713) 499-1155 Fax: (713) 499-1167	

Comment	Mitigation Option
A Mitigation Option should be added for Nuclear technology. We should not assume that it is too controversial for consideration. The U.S. Nuclear Regulatory Commission is staffing up to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, that has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. The most activity for these units will be in the south and southeast, where utilities have on-going nuclear experience. NRC has streamlined their processes so standard design certifications would be approved, and the safety design hurdle would not be raised continually. Most of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications. There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent cooling protection. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s. Benefits: Zero air emissions impact; No carbon footprint; cost effective electricity generation; foster high technology employment basis in Four Corners; proximity to future Nevada spent fuel storage site Tradeoffs: Negative public opinion; spent fuel containment Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up"	Proposed Power Plant - Desert Rock Energy Facility
I feel this (and perhaps one or two other power plants options) should be incorporated by reference into the monitoring section. There is a lot of good writing here.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The monitoring of degrading power plants deserves dual attention; both in this section and in the monitoring section for emphasis.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The Electric Power Research Institute (EPRI) today announced the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington,	Utility-Scale Photovoltaic Plants

Comment	**Mitigation Option**
NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The Solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.	
I would emphatically like to see this option included in the final report.	Reorganization of EPA Regions
The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.	Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

Other Sources

Other Sources: Preface

Overview

The Other Sources Work Group was charged with analyzing emissions mitigation strategies from all industrial, residential and transportation sectors that have emissions that significantly impact air quality in the Four Corners region. Although the work group was small, participation in the group involved state, local and tribal air quality agencies, industry representatives, public citizens, and representatives of environmental organizations.

Organization

The members of the Other Sources Work Group decided to focus on four main topic areas:

1. Transportation, including mobile sources
2. Land use, development, and planning
3. Burning
4. Alternative energy and fuels

Mitigation options for transportation issues included the following: including multi-modal transportation options in the 2035 transportation plan, including the Four Corners region into the Clean Cities designation for the Western Slope, encouraging local organizations to push for new projects and ordinances for transportation issues, developing requirements for anti-idling, school bus retrofits, increasing taxes for dirtier vehicles, developing a regional inspection and maintenance program, retrofitting or replacing oil and gas fleet vehicles, and looking at the Reid vapor pressure of fuels.

For land use, development and planning, the group discussed the consistency of regulations between jurisdictions for construction and sand and gravel operations, developing a regional planning organization for the region, phasing of projects to minimize blowing dust from bladed tracts of land, and developing a fugitive road dust plan.

Burning is handled very differently among the different jurisdictions in the Four Corners region. Mitigation options discussed for burning included public education and outreach, regulating agricultural burning in the Colorado portion of the region, providing a subsidy for cleaner fuels for residential heating, and using filter traps on wood stoves.

The alternative energy and fuels options were developed in conjunction with the Power Plants work group, and are included in the Energy Efficiency, Renewable Energy and Conservation section of this document.

Mitigation Option: Phased Construction Projects

I. Description of the mitigation option

Construction projects remove large quantities of vegetation leaving bare earth open to wind erosion, as well as to other environmental and biological degradation. Phasing these projects, large and even single residential development could lessen this environmental problem. Phasing re-vegetation would also result in decreased wind erosion.

Since phasing includes both small and large projects, this is something that individuals can have a part in as well as participating in for the larger community.

Benefits:

- Air quality – Particulate matter would decrease, protection of scenic views and economic benefits for tourism
- Environmental – Globally desertification is a big concern. The decrease in wind-blown particulates could delay man-made local desertification.
- Economic—construction would be phased according to building. Therefore, upfront costs would be also coordinated with sales, rather than all at the project beginning. Construction loans would also be phased.

Burdens:

- Developers may see change in methods as a threat to free enterprise.
- Construction managers would have to keep grading machinery on site locations throughout the project.

II. Description of how to implement

A. Mandatory or voluntary

Both. Mandatory for new construction. Incentives for individual homeowners to plant vegetation on disturbed sites.

B. Indicate the most appropriate agency(ies) to implement

Counties and towns in land use regulations, building permits. Local and state agencies may also implement programs for free compost or vegetation (e.g., native trees or shrubs for lot sizes over 1 acre).

III. Feasibility of the option

A. Technical – High
B. Environmental – High
C. Economic – High – may result in higher costs for construction projects in some areas.

IV. Background data and assumptions used

Help from monitoring work group to collect data downwind of

V. Any uncertainty associated with the option (Low, Medium, High) – Low

VI. Level of agreement within the work group for this mitigation option.

VII. Cross-over issues to the other source groups

Oil and gas and power plant work groups may look at phased development and revegetation for new projects.

Mitigation Option: Public Buy-in through Local Organizations to push for transportation alternatives and ordinances

I. Description of the mitigation option, including benefits and burdens.

Involve existing local organizations in supporting alternative transportation options. Go to meetings of existing organizations and discuss how they can help to promote clean air. Examples of the type of projects local organizations might support include bike paths, bike racks on buses, carpool lanes, and ride-share.

Benefits of applying this option might include reduced traffic congestion, reduction of fuel use, and boosts to local neighborhood economies. Burdens would be minimal though there may some tax increases may be necessary to fund the projects.

II. Description of how to implement

This would be a voluntary option. Agencies and task force members would implement by participation in local meetings. Publicity to encourage participation in organizations and support for alternatives might also be used. States could use these partnerships as early action compacts for State Implementation Plans.

III. Feasibility of the option

This option would be easy to implement because it is voluntary. While there may be some minimal cost for agencies to participate in local meetings it would be within their mission and a positive use of tax dollars.

IV. Background data and assumptions

The simplicity of this option requires no background analysis. It is assumed that individuals would make the effort to partner with local organizations.

V. Any uncertainty associated with the option

There is little uncertainty that this would be a viable and effective option.

VI. Level of agreement within the Work Group for this option

All work group members agree that this is a worthwhile option.

VII. Crossover issues to other workgroups

Involvement in planning for employee ridesharing may crossover to the Power Plant and Oil and Gas groups.

Mitigation Option: Regional Planning Organization for the Four Corners Region

I. Description of the mitigation option

The Four Corners region has a number of different jurisdictions and requirements. The air quality issues in the region are more widespread than local jurisdictions or agencies can address without working together as a regional planning organization (RPO). What occurs in one jurisdiction affects other jurisdictions, especially with respect to air quality. Although any one jurisdiction may have a very good program, that would be unlikely to have a widespread effect throughout the Four Corners region. The synergies of a region are much greater. In not duplicating efforts, costs will be lessened. States and local jurisdictions must be committed to the work of the RPO. RPO membership should be limited to those who have regulatory authority (e.g., towns, cities, counties, tribal governments, states).

II: Description of how to implement

Members could be appointed by local and/or state governments. Officers could be voted in by the members. Member entities would include the cities/towns of Durango, Farmington, Aztec, Cortez, Bloomfield, and Pagosa Springs; the tribes of Navajo Nation, Southern Ute, Ute Mountain Ute, Jicarilla Apache; and the counties of San Juan and Rio Arriba in New Mexico and Montezuma, La Plata and Archuleta in Colorado.

Meetings of the regional planning organization would be held on a regular schedule (perhaps quarterly) and open to the public. It is important that the governors of the Four Corners states support the organization. Local agencies would brief the governors and the state agencies on the need for a work of the organization. It is possible that this organization could be set up similarly to a Council of Governments organization. One way to begin the conversation to establish the RPO would be to ask the League of Women Voters or other task force members to present this idea to the Northwest New Mexico Council of Governments. Funding could be joint from states, tribes, local governments, and potentially EPA grants.

Another option would be to house this RPO within the Western Governors Association, perhaps similarly to the Western Regional Air Partnership with a scope limited to the Four Corners region.

III. Feasibility of option

If there are 2 or 3 local champions that are willing to dedicate time and energy, this could work. Also, support of the state agencies and governors would be critical.

IV. Background data and assumptions used Assume local governments will be willing to work together on these issues.

V. Any uncertainty associated with the option (Low, Medium, High) Medium, depending on local support.

VI. Level of agreement within the workgroup for this mitigation option Strong.

VII. Cross-over issues to other source groups

No, although it is similar in focus to the Overarching mitigation option on Reorganization of EPA Regions.

Mitigation Option: Develop Public Education and Outreach Campaign for Open Burning

I. Description of the mitigation option

This option involves the development of a public education and outreach campaign that would target the practice of open burning. The goals of this mitigation option are to 1) educate the public on the health dangers associated with open burning, 2) educate the public on the environmental/air quality damages of open burning, and 3) decrease the usage of open burning in the targeted communities.

Open burning is a more serious threat to public health and the environment than what was previously believed. Burning household waste produces many toxic chemicals and is one of the largest known sources of dioxins in the nation. Dioxins are highly toxic, long-lasting organic compounds that are extremely dangerous, even at low levels. Dioxins have been linked to serious health problems, including cancers and developmental and reproductive disorders. Other air pollutants such as particulate matter, sulfur dioxide, lead, mercury and hexachlorobenzene also affect adults and children with asthma or other lung diseases. Diseases related to the nervous system, kidneys and liver have also been linked to these pollutants.

II. Description of how to implement

A. Mandatory or Voluntary: This program would be a voluntary program hosted by local agencies or environmental groups.

B. Indicate the most appropriate agency(ies) to implement: Public Health, Environmental

III. Feasibility of the option

A. Technical: There are many similar open burning education campaigns present in Colorado, therefore it would not be difficult to receive technical support for the option.
B. Environmental: Since we are aware of the environmental dangers associated with open burning, there is much research available to use in educating the public.
C. Economic: Depending on the budget of the agencies, this program should not be prohibitive or expensive.

IV. Background data and assumptions used

1. Data on emissions from open burning was pulled from the EPA's Municipal Solid Waste Web site (www.epa.gov/msw)

V. Any uncertainty associated with the option (Low, Medium, High)

Medium

Mitigation Option: Automobile Emissions Inspection Program

I. Description of the mitigation option

Automobile emissions inspection/maintenance (IM) programs are a traditional mobile source strategy to control automotive emissions. They improve air quality through the identification and repair of high emitting vehicles. Vehicles that are repaired pollute less, improving air quality. They also get better fuel economy that contributes to reducing green house gas emissions.

Inspection/maintenance programs have been used to control automobile emissions since the early 1970s. They were originally used in New Jersey, Arizona and other states as early as 1974. They have been predominantly implemented in areas that are, or have been, out of attainment for ozone or carbon monoxide.

It is estimated that in urban areas, such as Denver or Albuquerque, motor vehicles contribute one-quarter to one-half of all the anthropogenic hydrocarbon and nitrogen oxide emissions, and three-fourths of the carbon monoxide emissions. Even in rural areas, automobiles can be a source for these emissions. Control of these emissions will reduce ozone concentrations, dependent on factors such as the NOx/HC ratio, amount of solar radiation, and meteorology/air mass movement and vertical mixing. Of importance is the fact that mobile source hydrocarbon emissions generally are higher in ozone reactivity (ability to make ozone) than other sources, such as natural gas production, thus may be important to control.

Table 1
2007 Denver metro VOC and NOx inventories
(tons per day)

	Mobile Inventory	Total Inventory
VOC	117.5	479.4
NOx	119.3	336.5

Source: CDPHE, Early Action Compact (EAC)

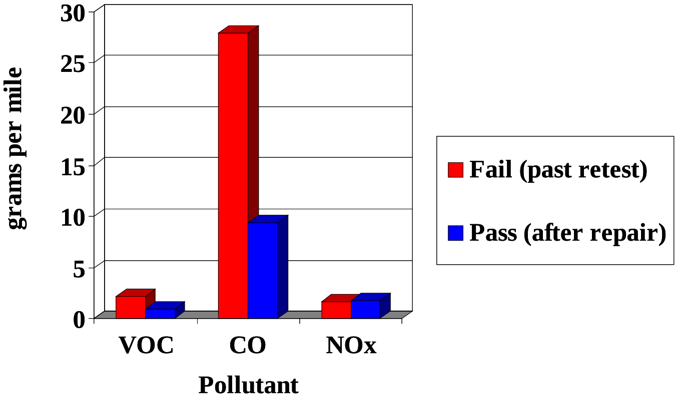
Repair Effectiveness

High emitting vehicles disproportionately contribute to mobile source emissions. Their repair is important in maintaining low overall mobile source inventories. Colorado inspection station data indicate that repairs to failing vehicles significantly reduce hydrocarbon emissions. Vehicles that failed their initial IM 240, and are later repaired, emit an average of 2.2 grams of hydrocarbons per mile. Upon passing a retest, these same vehicles emit an average of 1.0 gram of hydrocarbons per mile. This is a 57% reduction in the amount of hydrocarbons emitted by these vehicles.

Other emissions such as carbon monoxide, a weak ozone precursor, are similarly reduced. Motor vehicles that failed their initial IM 240 test, and are repaired, emit an average of 27.9 grams of carbon monoxide per mile. On a passing retest, these same vehicles emit an average of 9.4 grams of carbon monoxide per mile. This is a 66% reduction in the amount of carbon monoxide emitted by these vehicles. NOx emissions are not emphasized in Colorado’s program and are basically unchanged. Adoption of tighter NOx emission cutpoints would result in greater NOx benefit.

The repair effectiveness results of Colorado’s IM240 program are given in Figure 1.

Figure 1
2005 COLORADO IM240 TEST RESULTS
INITIAL FAILS VS FINAL PASSING TEST
ALL VEHICLES



On-Board Diagnostics

There are many different types of IM programs and IM tests. However, a simple cost-effective IM program is an on-board diagnostics (OBD) program, either as a stand-alone program for 1996 and newer model year vehicles, or one matched with an idle or other emissions test for 1995 and older vehicles. An OBD program can also be paired with an emissions test that measure a vehicle's emissions as well as examining their diagnostic codes. Examples of other emissions tests that may be paired with an OBD test are given in the attached appendix.

All 1996 and newer light duty vehicles are equipped with on-board diagnostics (OBD) technology. The intent of the OBD system is to monitor the vehicle's emissions control systems while the vehicle is in operation and detect potential problems as soon as they occur. Once a problem is detected, the system notifies the motorist by turning on a malfunction indicator light along with storing malfunction specific diagnostic information in the computer. The sensitivity of the system is programmed to detect a malfunction that may cause the vehicle's emissions to exceed 1.5 times its certification levels.

An OBD IM Program would require 1996 and newer model-year vehicles to undergo a periodic diagnostic check of all their stored trouble codes. If no malfunctions were identified the vehicle would pass. If malfunctions were identified, the vehicle would be required to be repaired. The following table identifies the IM benefit of an OBD-only program and an OBD program linked to an exhaust emissions test, in this case an IM240 test, for the Denver area fleet in 2007.

Table 2
OBD & OBD/IM240 Benefit
2007 Denver-Metro Fleet

	No I/M (gpm)		**OBD only (gpm)**	**% Benefit**		**OBD w/IM240 (gpm)**	**% Benefit**
HC	1.364		1.313	3.7		1.25	8.4
CO	13.627		12.832	5.8		11.959	12.2
NOx	1.392		1.334	4.2		1.315	5.5

Source: CDPHE, MOBILE 6 / 2007 Denver-metro fleet

II: Description of how to implement

An on-board diagnostics (OBD) program can be implemented as a contractor operated centralized IM program, or a decentralized inspection program, or decentralized inspection and repair program. State/local/or contractor staff would undertake program design, after authority for such a program is established through the state legislature and/or regulatory boards. Enforcement would be through state or local program enforcement staff. Registration denial would be the most effective way of maintaining program compliance.

III. Feasibility of option

An OBD program either with or without an emissions test is very feasible. Currently 32 states and the District of Columbia operate such a program, or will in the near future. Additionally, new innovative OBD features, such as self-standing, self-serve OBD kiosks, and loaner radio transponders are being implemented or are under development in Washington and California.

IV. Background data and assumptions used

Emission factors were generated by the U.S. EPA MOBILE 6b model. They reflect the Denver area fleet and transportation network for 2007. Repair effectiveness data is from the Colorado IM 240 program, and represents emission data derived from load-mode transient IM 240 testing. Inventories showing mobile source contribution are for the Denver metro area. Mobile sources' contribution is expected to be less in rural areas.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. OBD Programs are proven strategies. A higher uncertainty exists for add-on elements such as implementation of self-standing, self-serve OBD kiosks, and loaner radio transponders. The greatest uncertainty is the integration of the data network with vehicle registration records and county clerk renewal processes. In states, such as Colorado, with existing IM Programs this is not an issue.

VI. Level of agreement within the workgroup for this mitigation option Good general agreement.

VII. Cross-over issues to other source groups

IM (inspection/maintenance) programs offer the ability to assist in controlling mobile source contributions to ozone formation, regional haze, air toxics, and global warming. There will be little cross-over issues with other groups. An IM program could affect gasoline vehicles used in oil and gas production, or other work covered by other groups, but generally there will be minimum cross-over.

As diesel vehicles and off-road vehicles are equipped with OBD features, they could conceivably be included in their own OBD programs. On-road diesels registered in the Front Range of Colorado currently participate in an opacity IM program.

Appendices

Significant Emissions Tests

On-Board Diagnostics

This technology is installed on 1996 and newer light-duty cars and trucks. It uses the vehicle's computer to identify potential emissions problems. If a problem exists, the system is required to warn the driver by displaying a warning light. Also, a "fault code" is simultaneously stored in memory identifying the problem area. Drivers are required to visit a test station periodically to have their vehicles "scanned" for fault codes This takes only a short amount of time. There is good accuracy in detecting potential problems with this test.

Idle Test

Initially used in New Jersey, Arizona and other states as early as 1974, emissions measurements take place while the engine is at the steady-state condition of idle. Over the years, minor changes were introduced and there are now six different idle test "types." Colorado first used this test in 1981 and still uses a modified version on heavy-duty vehicles, and older light-duty vehicles, in the Denver metropolitan program area. The major advantage of these tests is the relatively low equipment costs ranging from $15,000 to $20,000. The major drawback is a high level of false "passes" caused by newer technology on today's vehicles.

Acceleration Simulation Mode

In an attempt to increase accuracy, this newer class of steady-state test uses similar analytical equipment to the idle test, but also includes a dynamometer to "load" or "exercise" the vehicle at a constant speed. This test is designed primarily for states that are not in attainment for ozone.

A good example of the load applied to the vehicle during testing would be comparable to driving at a steady speed of 15 miles per hour on an eight percent grade hill, similar to the section of I-70 between the Morrison and Lookout Mountain exits, or at 25 miles per hour on a five percent grade hill, about half as steep as the previous example. The intent is to simulate an acceleration of the vehicle.

The two major positive elements of this test are the addition of nitrogen oxide emission measurements, and moderate equipment costs of $35,000 to $60,000.

Transient Tests

This class of test also utilizes a dynamometer but uses significantly more accurate analytical equipment and varies the vehicle speed during the inspection. The dynamometer load applied to the vehicle drive train is more similar to actual driving on a road. Test accuracy is the major positive element, with high equipment costs, often more than $100,000 being the major drawback. Because of the cost, transient tests usually are centralized due to economies of scale. The following major options are examples of transient tests.

IM 240

The IM 240 (Inspection and Maintenance, 240 seconds) is a shortened version of the Federal Test Procedure and is used in the Denver metropolitan program area. Vehicle speed is varied between 0 and 57 miles per hour. This test generally is considered to be the best predictor of the Federal Test Procedure.

IM 93

A shortened version of the IM 240, the IM 93 incorporates only the first 93 seconds. Top speed is approximately 36 miles per hour.

BAR 31

The BAR 31 (California Bureau of Automotive Repair, 31 seconds) is another loaded mode test, which has a maximum speed of 30 miles per hour and a driving time of 31 seconds, which can be repeated up to four times before failing the vehicle.

Other Predictive Options

Vehicle "Profiling"

Vehicle profiling runs in parallel with an existing inspection program. Using current inspection information, it is possible to predict whether a vehicle is likely to pass or fail based on the year, make and model. This increases the cost effectiveness of the inspection program by reducing the amount of resources needed for a full inspection test.

Low Emitter Profile

This method attempts to identify vehicles that are likely to be relatively "clean" vehicles or very low emitters. This can be done by analyzing current inspection data and predicting the probability that a certain year, make and model vehicle will pass the test.

High Emitter Profile

This method generally attempts to identify vehicles that are likely to be "dirty" or high emitters. Once identified, either through past inspection records of a specific vehicle, or because certain years, makes and models tend to be high polluters, targeted vehicles are subject to special treatment. Usually, this includes restricting the vehicle inspections to stations with higher quality control procedures and/or increasing the test frequency, e.g., substituting an annual inspection cycle for what would normally be a biennial cycle. Colorado does not use high emitter profiling in its inspection program.

Remote Sensing Clean Screen

Rather than trying to shorten or enhance a state's emission test, this technology attempts to "pre-screen" a vehicle as it drives by a remote sensing device placed on a roadside. If multiple readings indicate the car or truck is a low polluter, the vehicle owner is exempted for one test cycle from having to visit a traditional test station. The major benefit of this program is reduced inconvenience to owners of low polluting vehicles. A drawback is that some vehicles may be exempted that would normally fail the emissions test. However, by monitoring test conditions, this can be kept to a reasonable level that still meets air quality objectives. Additional issues are described in the body of this report.

Remote Sensing High Emitter Identification

As a vehicle drives by a remote sensing device, its emissions are measured. Vehicles with high enough emissions are required to come in for a confirmatory IM inspection.

Model Year Exemption

Another method of Low Emitter Profiling is exempting by model year. For instance, it is extremely unlikely that a new vehicle will fail an emissions test during the first few years from when it was manufactured. The case has been made that it is a waste of inspection resources and an owner's time to test those vehicles. Colorado exempts new cars from testing requirements for four model years.

Mitigation Option: Low Reid Vapor Pressure (RVP) Gasoline

I. Description of the mitigation option

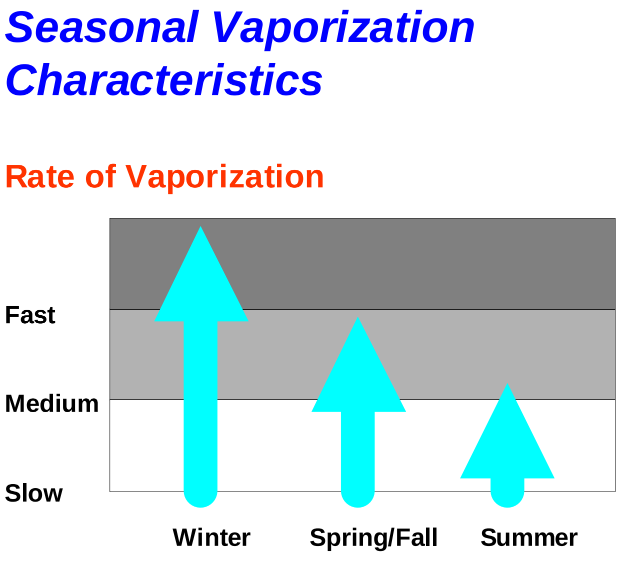
A major source of hydrocarbon emissions is the evaporative emissions produced by gasoline. Evaporative emissions occur during the refining process, through transportation and storage to the service station, and finally in refueling and operation of motor vehicles. The rate at which these emissions are produced is directly related to the fuel’s volatility. The higher the volatility of the gasoline, the more volatile organic compounds (VOCs) are emitted at any given temperature.

One method to control gasoline evaporative emissions that contribute to ozone formation is to lower the volatility of gasoline, especially during the summer months. For most areas, summertime volatility is controlled by the U.S. Environmental Protection Agency (U.S. EPA). Under the Clean Air Act Amendments of 1990, the administrator of the U.S. EPA is charged with designating volatility standards for areas based on their air quality needs.

The U.S. EPA has set a gasoline volatility standard of 9.0 pounds per square inch (9.0 lbs.) for northern areas that meet the National Ambient Air Quality Standard for ozone. Air quality agencies with non-attainment areas may choose a different standard in their State Implementation Plan (SIP), or use the default standard set by the U.S. EPA.

Volatility outside the U.S. EPA controlled summer season (May 1st through September 15th) is generally controlled in most states by the American Society of Testing and Materials (ASTM) standards. These standards are set by national committees to reflect standards needed for good automotive operation and drivability.

Generally speaking, higher RVP is useful during the colder winter months to allow for easy cold weather starting and operation. Lower volatility is required during the warmer months, including summer, to prevent vehicle vapor locking and decreased drivability. The following chart shows this relationship.



SOURCE: Changes in Gasoline III

Air Quality Benefits of Lower Volatility Gasoline

As part of its efforts to reduce summertime ozone, the Denver area examined the benefits of lower volatility of gasoline. This analysis, part of Colorado's Early Action Compact (EAC) found that reducing gasoline RVP from 9.0 pounds per square inch (lbs.) to 8.1 lbs. would reduce mobile source evaporative emissions by 10 tons of VOC per day. Lowering gasoline volatility still further to 7.8 lbs. was found to reduce evaporative emissions by 13 tons of VOC per day. This represents a 7.8% to 10.2% VOC reduction in mobile source emissions.

Table 1
2007 Denver Metro VOC Inventories
(tons per day)

Reid Vapor Pressure	Mobile Inventory	Mobile Source Benefit	Total Inventory
9.0 lbs.	128	0	489
8.1 lbs.	118	10	479
7.8 lbs.	115	13	476

Source: CDPHE, Early Action Compact (EAC)

Cost

In examining the use of lower volatility gasoline to reduce VOC emissions, it was estimated that the price of gasoline would be expected to increase by one or two cents per gallon. For the Denver area it was estimated that this would equate to $8,600 per ton for 8.1 lb. RVP gasoline and $13,300 per ton for 7.8 lb. RVP gasoline. Because of high ozone measurements in the summer of 2005, and the fact that Denver had been originally been designated as a 7.8 lb. RVP area by the EPA administrator in the early 1990s (though had a received a series of waivers from this requirement), the U.S. EPA reestablished the 7.8 lb. RVP requirement for the Denver area starting with the summer of 2004.

Outside of the Denver area, all of Colorado continues to have a 9.0 lb. RVP maximum for gasoline sold between June 1st and September 15th. Most of Utah (outside of Davis and Salt Lake counties) also has this summer maximum, as does New Mexico and most of Arizona (outside of part of Maricopa County). The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA 2001, diagrams the various summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

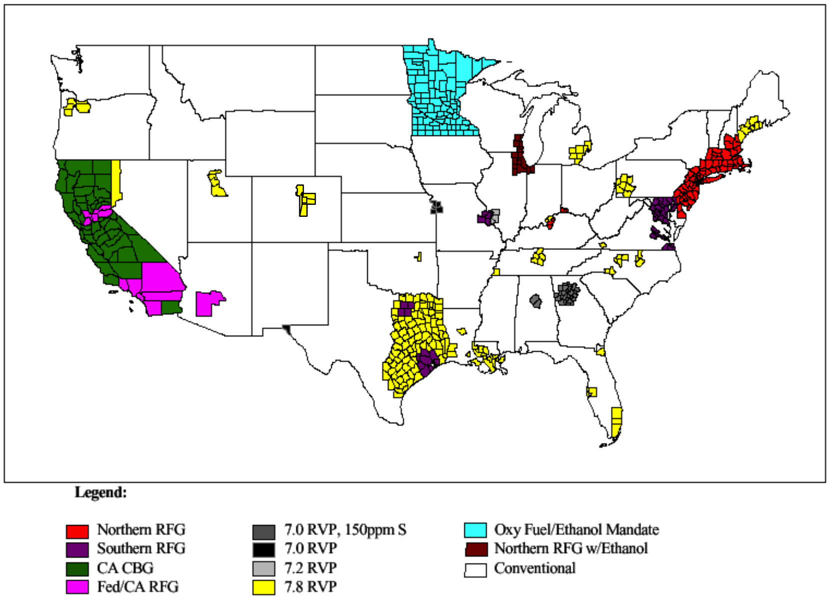


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a low RVP program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. If low RVP was required as a state program, the state would enforce the requirements. If it was an U.S. EPA program, the federal government would enforce.

III. Feasibility of option:

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the workgroup for this mitigation option Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Use of Reformulated Gasoline

I. Description of the mitigation option

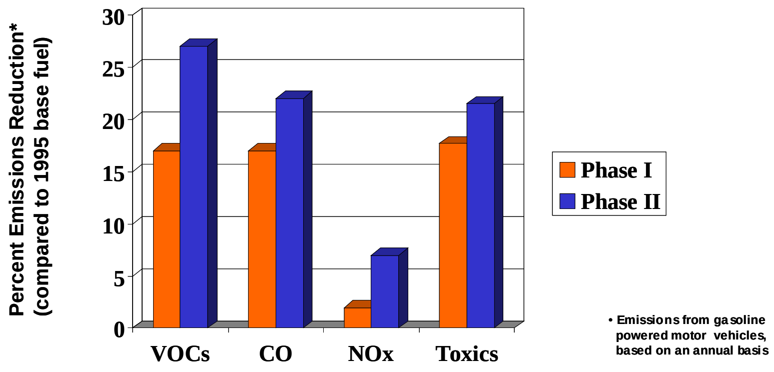
The use of reformulated gasoline (RFG) is an effective way of reducing ozone precursors from gasoline powered motor vehicles. Their use was first mandated in the nine most severe ozone nonattainment areas by the Clean Air Act Amendments of 1990. These areas included: Los Angeles, San Diego, Chicago, Houston, Milwaukee, Baltimore, Philadelphia, Hartford, and New York City. Others areas have since "opted" into the federal program. At last count, there are now 17 states and the District of Columbia that require its use. California implemented its own program beginning in 1992.

Reformulated gasoline is gasoline that has been reformulated to lower ozone precursors. While gasoline is generally formulated for the time of year or season, geographical location, altitude, and other conditions, reformulated gasoline is specifically formulated for emissions. Usually the distillation curve of the fuel (including Reid vapor pressure) is adjusted as well as other properties (light ends, olefin and aromatic content, etc.). By Clean Air Act requirement, an oxygenate, such as ethanol, is added. California reformulated gasoline goes an additional step in weighing hydrocarbon ozone forming reactivity in their performance-based standards.

Air Quality Benefits

Under the original federal specifications, the use of federal Phase I reformulated gasoline (1995) was expected to reduce hydrocarbon and air toxic emissions by 15% compared to conventional gasoline. Phase II reformulated gasoline (2000) was mandated to reduce hydrocarbon and air toxic emissions by approximately 22%.

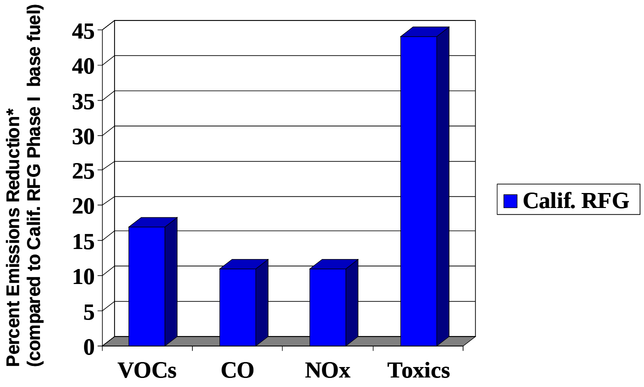
Emissions Impacts of RFG Phase I vs. RFG Phase II



• Emissions from gasoline powered motor vehicles, based on an annual basis

Source: US EPA,"Phase 11 Reformulated Gasoline: The Next Major Step Toward Cleaner Air", Nov 1999, except for air toxics, EIA/DOE

California (CA) reformulated gasoline is even a more stringent formulation. The latest Phase 3 reformulated gasoline standards, based on the CaRFG3 predictive model, are 11% to 17% lower in HC, CO, and NOx emissions and 44% for air toxics compared to the original Phase 1 specifications introduced in 1992, itself a low ozone and air toxics formulation with caps on olefin and benzene content.



Emissions Impacts of Calif. RFG Phase II/III vs. Calif. RFG Phase I

Source: Chevron: "Gas and Air Quality: Reformulated Gasoline", Chevron

California Phase 2 reform (introduced in 1996) was estimated by the California Air Resources Board (CARB) to be twice as effective as Phase I federal reform of the same era. Phase 3 reformulated gasoline is very similar to CA Phase 2 in emissions, but does not use methyl tertiary-butyl ether (MTBE), an oxygenate found to contaminate groundwater if released during fuel spills or leaks.

Cost

Reformulated gasoline is more expensive than conventional gasoline to produce (though this is less so with the implementation of federal Tier II conventional gasoline requirements beginning in 2005). The U.S. EPA estimated that Phase I federal reformulated gasoline typically cost between three and five cents per gallon more to produce than conventional gasoline, with Phase II reform costing an additional one to two cents. CARB estimated California reformulated Phase 2 gasoline to be between five and fifteen cents per gallon more expensive than conventional gasoline.

Supply issues come into play with reformulated gasoline. While most refineries can easily make it, their facilities may not always be optimized to produce it. California reform is even more subject to these limitations.

Approximately 30% of all gasoline now sold in the United States is reformulated. The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA, 2001, diagrams the various reformulated gasoline program areas, as well as summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

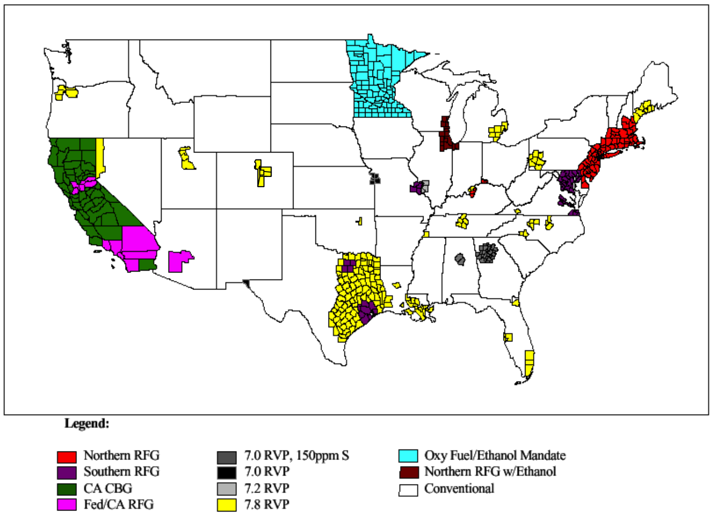


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a RFG program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. Typically a state will "opt" in to the federal reformulated gasoline program, with the federal government enforcing the program. If so desired the state may implement and enforce their own state RFG program. However, state programs must be identical to federal or California RFG programs.

III. Feasibility of option

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. The use of reformulated gasoline would require that there be available supplies. A major refiner close to the four-corners area, Valero's McKee refinery located in the panhandle of Texas, already manufactures reformulated gasoline for Texas and other reformulated gasoline markets. The question is whether it and other refineries have the capacity, at a reasonable cost, to produce enough RFG for the Four Corners area.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Idle Ordinances

I. Description of the mitigation option

Motor vehicle idling is a source of preventable mobile source emissions. Recognizing that most vehicles do not need to idle, many cities have passed local ordinances banning excessive vehicle idling, specifically for heavy-duty vehicles such as trucks and buses. Voluntary idling programs may also be used, especially for gasoline powered light-duty vehicles.

Most city ordinances set the maximum idling time at two to five continuous minutes. Some have longer time limits. In Maricopa County, Arizona the time limit is five minutes. In Denver and Aurora, Colorado the time limit is 10 minutes in any one-hour period. Philadelphia has a minimum two minutes. The Houston/Galveston nonattainment area has a minimum of five minutes from April 1st through Oct. 31st. Salt Lake City permits up to 15 minutes of continuous idling.

Emissions Reductions

Idling ordinances generally target heavier diesel trucks and buses and particulate (PM) emissions. However, there is no reason to preclude light-duty gasoline vehicles. All internal combustion vehicles emit pollutants and green house gases. It is estimated that larger trucks and buses burn from one-half to one gallon of fuel per hour of idling (1,2), all of which produce unnecessary emissions. Light-duty gasoline vehicle fuel consumption may be half to a quarter of this.

According to Air Watch Northwest, a consortium of air quality management agencies in Washington state, Oregon, and British Columbia (www.airwatchnorthwest.com), cars at idle emit a comparable amount of pollution to when it is driven (3). This is especially true when a vehicle is started cold, before its catalytic converter is warm enough to become effective. Once warm, a catalyst will stay warm for quite some time, so shutting down an engine to conserve fuel and limit emissions will generally have little effect on catalytic effectiveness when the vehicle is restarted.

The following tables list the average emission for vehicles at idle. The first two are for passenger cars and light trucks. The third table lists emissions for heavy-duty trucks and buses. Data is from April 1998. The acronyms used in the charts are listed below. All data is from U.S. EPA, and may be obtained at: http://www.epa.gov/otaq/consumer/f98014.pdf

LDGV	Light-duty gas vehicle
LDGT	Light-duty gas truck
HDGV	Heavy-duty gas vehicle
LDDV	Light-duty diesel vehicle
LDDT	Light-duty diesel truck
HDDV	Heavy-duty diesel vehicle
MC	Misc

U.S. EPA Estimated Idle Emissions
for Passenger Cars and Light Trucks

Summer Conditions (75 degrees F., 9.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	16.1	24.1	35.8	3.53	4.63	12.5	19.4
	g/min	0.269	0.401	0.597	0.059	0.077	0.208	0.324
CO	g/hr	229	339	738	9.97	11.2	94.0	435
	g/min	3.82	5.65	12.3	0.166	0.187	1.57	7.26
NOx	g/hr	4.72	5.71	10.2	6.50	6.67	55.0	1.69
	g/min	0.079	0.095	0.170	0.108	0.111	0.917	0.028

Winter Conditions (30 degrees F., 13.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	21.1	30.7	44.6	3.63	4.79	12.6	20.1
	g/min	0.352	0.512	0.734	0.061	0.080	0.211	0.335
CO	g/hr	371	487	682	10.1	11.5	94.6	388
	g/min	6.19	8.12	11.4	0.168	0.191	1.58	6.47
NOx	g/hr	6.16	7.47	11.8	6.66	6.89	56.7	2.51
	g/min	0.103	0.125	0.196	0.111	0.115	0.945	0.042

U.S. EPA Estimated Idle Emissions
for Heavy –Duty Trucks and Buses

Engine Size	Emissions
Light/Medium HDDVs (8501-33,000 GVW)	2.62 g/hr (0.044 g/min)
Heavy HDDVs (33,001+ GVW)	2.57 g/hr (0.043 g/min)
HDD buses (all buses, urban and inter-city travel)	2.52 g/hr (0.042 g/min)
Average of all heavy-duty diesel engines	2.59 g/hr (0.043 g/min)

These average idle emissions may be compared to average vehicle emissions by comparing the first two tables with the table listed below. This data may be obtained at:
http://www.epa.gov/otaq/consumer/f00013.htm

U.S. EPA Emissions Facts
Average Annual Emissions and Fuel Consumption
for Passenger Cars and Light Trucks

Component	Car Emission Rate Fuel Consumption	Light Truck Emission Rate Fuel Consumption
HC	2.80 g/mi	3.51 g/mi
CO	20.9 g/mi	27.7 g/mi
NOx	1.39 g/mi	0.81 g/mi
CO2	0.915 lbs/mi	1.15 lbs/mi
Gasoline	0.0465 gal/mi	0.0581 gal/mi

As can be seen by a comparison of the above tables, for volatile organic compounds (VOCs), it will take eight minutes of idling to equal one mile of driving for an average automobile during the summer. For carbon monoxide (CO) this is approximately five and a half minutes, and, for nitrogen oxides (NOx) this is approximately seventeen and a half minutes.

Particulate Emissions

One reason to adopt idling ordinances or some voluntary program to reduce idling is the exposure to particulate emissions. One of the principle sources of particulate matter (PM) exposure is from diesel vehicles. This is of utmost importance when it comes to school-age children and their exposure to diesel school bus particulate and air toxic emissions. On average, children and adults may be exposed to excessive levels of PM from idling diesel trucks and buses. As the above table points out, an average heavy-duty diesel truck or bus will produce approximately 2.6 grams of particulates per hour. It should be noted that federal health-based PM standards are measured in the micrograms (not grams) range. The short term PM standard for PM_{10} is $150ug/m^3$ for a 24-hour average.

Technologies Used to Reduce Truck Idling

A number of strategies can be used to assist vehicles, mostly trucks and buses, from needing to idle while maintaining heating and cooling capacity. For larger trucks and buses, stand-alone direct-fired heating devices are available that cost from $1000 to $2000. Automatic engine idling devices may also be used that continue air conditioning when the engine is turned off at a cost of $1000 to $2000. Most expensively, small power generating auxiliary power units may be used, each costing from $5000 to $7000 (2).

At truck stops, fleet locations, and other stationary parking facilities, truck-stop electrification may be utilized. “Shore power” is provided directly to the parked truck, linking it to the power grid for all its electrical needs. This is estimated to cost $2500 per truck space and another $2500 per truck to modify so that it can receive the electricity (2).

References:
(1). U.S. EPA
(2). Philadelphia Diesel Difference Working Group
(3). Air Watch Northwest

II: Description of how to implement

Generally local government may adopt ordinances limiting vehicle idling, principally heavy-duty diesel truck or bus idling. School districts can modify their procedures to prevent excessive school bus idling. Trucking fleets, including oil and gas extraction fleets can also implement updated policies for their drivers.

Local air planning agencies, state, or local government can also implement voluntary programs, aimed at both light-duty gasoline vehicles as well as heavy-duty diesel vehicles. Voluntary programs can be established relatively easily and in a minimal amount of time. Infrastructure to promote auxiliary power for trucks to use at truck stops, distribution centers (think Walmart), etc., would take more time and money to accomplish.

III. Feasibility of option

This is a very feasible option. Idling ordinances and voluntary idling reduction programs have been established for a number of years in many locations.

IV. Background data and assumptions used

Emission estimates are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. Idling ordinances and voluntary idling reduction programs are proven strategies.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement.

VII. Cross-over issues to other source groups

There will be little cross-over issues with other groups, except for fleets, such as involved in oil and gas extraction.

Mitigation Option: School Bus Retrofit

I. Description of the mitigation option

One of the most significant sources of particulate and air toxic exposures that young school-age children are exposed to are diesel school bus emissions. Older diesel school buses contribute a greater proportion of particulate (PM), as well as nitrogen oxide (NOx) and hydrocarbon (HC) emissions, compared to current buses built to the newest emission certification standards.

While the newest school bus emissions standards have just been implemented, school buses have long lives, permitting older higher emitting school buses to continue to expose children to high levels of diesel exhaust and to contribute to summertime ozone precursors. Reducing emissions from these buses will result in emission reductions that will last for years.

One method of reducing emissions from these older school buses is through school bus retrofit programs. Retrofit programs achieve their air quality benefit by improving the emissions characteristics of the existing school bus. Improvements may range from re-powering school buses with new replacement engines, or adding better emission control equipment, to using cleaner sources of fuel.

Emissions Reductions

PM Emissions

It is estimated by the U.S. EPA that oxidation catalytic converters retrofitted to buses reduce PM emissions by 20% to 30%, at a cost of $1000 to $2000 per bus(1). Retrofitting with a particulate trap reduces particulate matter by 60% to 90%, at a cost of $5000 to $10,000 per bus(1).

The use of ultra-low sulfur diesel fuel (required since 2006) allows these components to be added without the sulfur in diesel fuel contaminating the retrofitted equipment with a consequential loss in efficiency or damage. Ultra-low sulfur diesel fuel (maximum of 15 ppm sulfur content) is by itself expected to reduce particulate emissions by 5% to 9% (1).

Natural gas fueled school buses, if done correctly, can reduce particulate emissions by 70% to 90% at an additional cost of approximately $30,000 per bus(1). Replacement engines could reduce particulate emissions by 95% (2) as well as substantially reducing HC and NOx emissions.

Hydrocarbon and Carbon Monoxide Emissions

For ozone precursors, oxidation catalytic converters can reduce HC emissions by up to 50%. Carbon monoxide emissions may be reduced by up to 40%(2). Particulate traps will give some benefit, but are principally designed to lower particulate emissions.

The use of biodiesel fuel does reduce HC emissions, though its use will tend to increase NOx emissions (B20 up to 2%, B100 up to 10%(1)). Depending on the technology used, natural gas fueled school buses substantially lower NMHC. The U.S. EPA estimates NMHC emissions are reduced by 60%(1). NOx emissions, especially if lean-burn natural gas engines are used, may be lowered by a comparable amount. New technology replacement engines, built under the newest emissions certification standards would have substantial HC+NOx emission reductions.

The U.S. EPA has a technology Options Chart that they developed for their Clean School Bus USA Program. It lists the various technology options, their costs, and their benefits. It can be accessed at: http://www.epa.gov/cleanschoolbus/technology.htm.

Sources:
U.S. EPA Clean School Bus USA
Illinois Clean School Bus Program

Funding
There are various sources of funding for school bus retrofit programs. The U.S. EPA has annually funded retrofit programs. In 2007 they received seven million dollars under continuing resolution (H.J.R. 20) to fund projects nationwide. Eligible applicants that may apply for these funds include: state and local government, federally recognized Indian tribes, and non-profit organizations. Other sources of funding and grants include federal Congestion Mitigation and Air Quality (CMAQ) Program funds.

II: Description of how to implement

Local air planning agencies, state, or local government can implement these programs. Generally, they are funded through grants or other funding sources. They can be established relatively easily, with the needed outside infrastructure currently in place.

III. Feasibility of option

This is a very feasible option. School bus retrofit programs are operating throughout the United States.

IV. Background data and assumptions used

Emission reductions are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. School Bus Retrofit Programs are proven strategies

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement.

VII. Cross-over issues to other source groups

There will be little cross-over issues with other groups.

Mitigation Option: Subsidy Program for Cleaner Residential Fuels

I. Description of the mitigation option

Many families and individuals are forced by circumstances (economic, lack of availability, insufficient fuel delivery infrastructure, etc.) to use less than desirable fuels for cooking and heating. Many of these fuels, such as wood burning, emit high levels of toxic, or harmful, emissions, and carbon monoxide, hydrocarbon and organic compounds that are ozone precursors.

An option to reduce emissions that contribute to increased VOC, PM, CO, and air toxics is to promote the use of less polluting home heating and cooking fuels, especially electricity, propane, and natural gas in place of wood, coal, and kerosene. If wood is to continue to be used for home heating, at least a high efficiency EPA Phase II certified stove should be used.

Subsidizing Increased Cost of Fuel

Subsidizing the use of propane, natural gas, or electricity may allow low-income families to utilize these fuels in place of wood burning or other fuel sources, such as coal. Subsidy could be pegged to the economic need of the family, much like other welfare programs.

Home Heating

Replacing a traditional, non-certified wood stove with an oil furnace will reduce particulate (PM) emissions by over 99%, from 18.5 g/hr to 0.07 g/hr. Replacement with a natural gas furnace would reduce PM emissions even further to 0.04 g/hr (2).

The use of oil or gas furnaces in place of wood stoves would also have a substantial effect on carbon monoxide and emissions of hydrocarbons and other organic compounds, many of which have high ozone reactivities, as well as being fairly toxic gases. Encouraging the use of substituting electric or gas heat for cooking would similarly give a comparable emissions benefit.

New York State Environmental Protection Bureau estimates that a typical high efficiency (90%) gas or oil forced hot air furnace costs approximately $2690. This compares to a new EPA certified, catalytic equipped wood stove at approximately $2425, with a 72% efficiency rating (2).

Cleaner Wood Stoves

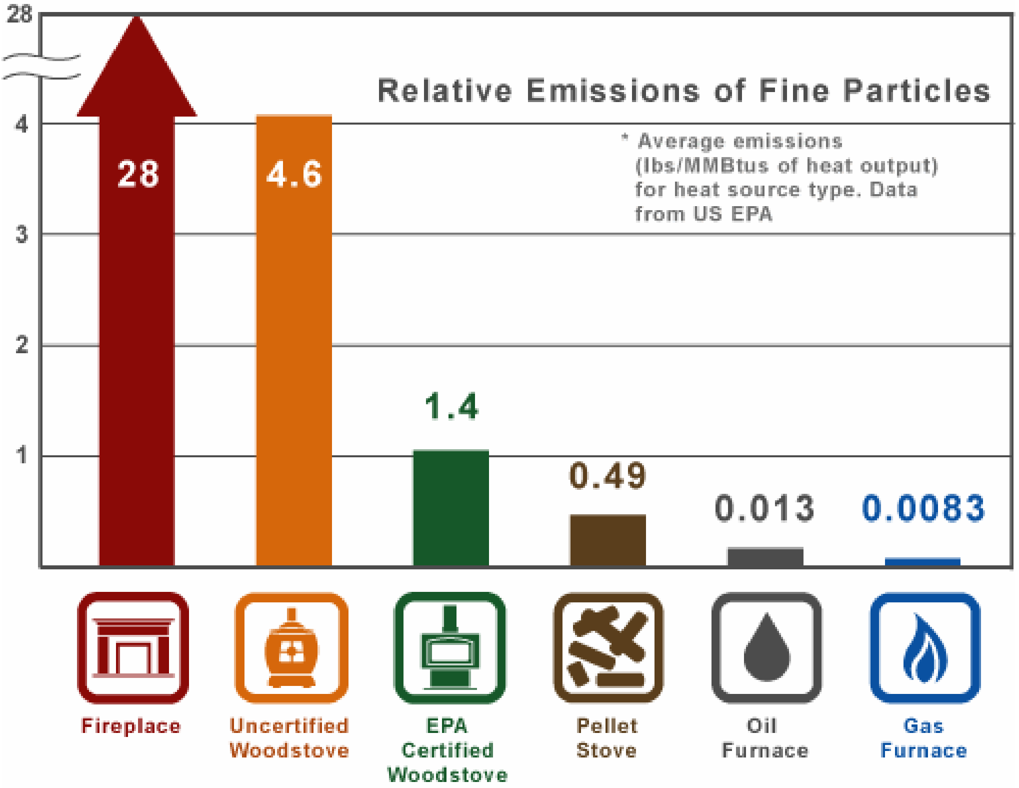
If a woodstove were used, it should be a new EPA certified one that would be expected to reduce fine particulate emission by 70% compared to an older non-controlled stove. Polycyclic aromatic hydrocarbons would be expected to go down from 0.36g/hr to 0.14 - 0.15 g/hr for EPA Phase I certified stoves to less than that for EPA Phase II certified stoves (2).

Nationwide, wood burning accounts for nine percent of home heating needs. However, it accounts for 45% of all particulate emissions from home heating (2). U.S. EPA Phase II standards are 7.5 g/hr PM for non-catalytic equipped stoves, and 4.1 g/hr PM for catalytic equipped ones (1,2). These standards are designed to reduce woodstove emissions by 60% to 80%(1).

In replacing an older uncontrolled stove with a new EPA certified stove, it is important to use an outside source of air for the heater box for combustion proposes. This prevents the stove from depleting a room’s oxygen content, as well as preventing emissions from entering the house. Stoves should also have catalytic converters to ensure the lowest emissions. Common models currently may produce from 35,000 to 100,000 BTU, and are able to heat rooms from 400 to 2000, or more, square feet(3). US EPA has a website at: http://www.epa.gov/woodstoves, where more information may be obtained.

Chart One
Relative Emissions of Fine Particulates
(Grams per Hour)

U.S. EPA Chart



Source: U.S. EPA

Reference Sources:
(1). U.S. EPA
(2). New York State Environmental Protection Bureau
(3). Chimney Sweep, Inc.

II: Description of how to implement

This program may be organized much like Low Income Energy Assistance programs. A means test or other criteria could be established to prioritize available funding.

Funding this program, or set of programs, may include tax incentives, or other methods, such as voluntary grants from the natural gas extraction industry, mineral surtaxes, or drilling and permit fees. Enforcement penalties could also be used.

III. Feasibility of option

The program is very feasible. It would not only reduce emissions that could aggravate ambient ozone, PM, and CO, but would reduce toxic exposure to inhabitants of the house and nearby homes.

IV. Background data and assumptions used

It is assumed that there is a sufficient population that would benefit from an assistance program.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Such a program, unless funded voluntarily as a public outreach program by industry, may require additional statutory authority, requiring legislative action, as well as well as regulatory development and adoption.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement. The option was agreed upon by the workgroup without dissent.

VII. Cross-over issues to other source groups

There are no cross-over issues identified at the present time.

Mitigation Option: Stage One Vapor Recovery

I. Description of the mitigation option:

Mandatory use of stage-one vapor recover systems will reduce evaporative emissions from service stations.

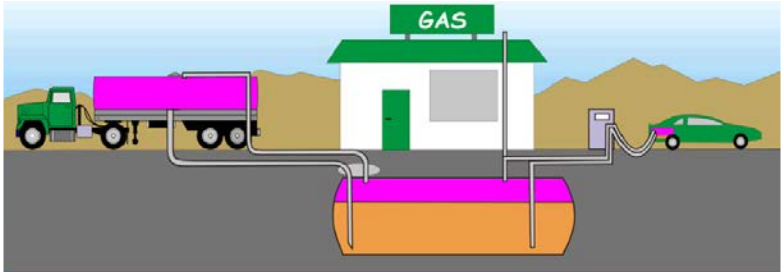
Refueling of underground service station tanks is a major source of evaporative hydrocarbon emissions. VOCs are released as the underground storage tank is refilled, when gasoline vapors in the tank's headspace are displaced. Sources estimate that 10-15 liquid gallons of gasoline are released from vapors displaced from the headspaces of various tanks, each time a gasoline transport truck fully unloads its products (1,2,3). Unless captured through a vapor recovery system, such as Stage I, these emissions will be released directly into the atmosphere.

In many areas, Stage I vapor recovery systems are required to control VOC emissions within the gasoline distribution system, from the refinery to the retail gasoline station. In the Denver metropolitan area, for instance, Stage I is required to control VOC releases that contribute to summertime ozone formation. Fire codes require the use of Stage I at service stations in other areas. But in many places their use is not required, and stations may, or may not, be using any vapor recovery stations, even if they are equipped with them. Stations that are equipped with Stage I vapor recovery systems may not be operating them. Other older stations may not even be equipped with vapor recovery systems.

The following diagram shows how Stage I works. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

The same illustration also shows how Stage II vapor recovery systems work, by using the same principle, capturing the VOCs produced as an automobile is refueled. As the automobile is refueled, vapors displaced by the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck.

Stage I Vapor Recovery



Source: Calif. EPA, Nov.18, 2004

References:

"What You Should Know About Vapor Recovery", Michigan Department of Environmental Quality.
"Keeping It Clean: Making Safe and Spill-Free Motor Fuel Deliveries," Petroleum Equipment Institute, December 1992.
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.

Air Quality Benefits of Stage One Vapor Recovery

As part of its effort to reduce summertime ozone, the Denver metropolitan area requires the use of Stage 1 at all service stations. It is estimated that because of Stage I requirements, that perhaps 13.2 million pounds of VOCs (18.1 tons per day) are prevented from being emitted into the air*. Air toxics are also reduced.

Stage I vapor recovery systems are efficient. Up to 95%(1) of underground storage-tank refueling vapors are captured. Stage I is also cost effective. Vapors from the underground storage tanks are collected in the now empty tanker truck's compartments and taken back to the refinery or terminal, where they are condensed and reused. At $3.00 a gallon for gasoline seen in the summer of 2007, this equates to $2.1 million dollars worth of gasoline saved annually.

(1), Hensel, John, and Mike Mondloch,"Stage One Vapor Control In Minnesota", Minnesota Pollution Control Agency.

* Based on emission factors from the state of New Hampshire (11 lbs. VOC produced per 1000 gallons of gasoline vapors displaced), and 1.2 billon gallons of gasoline delivered to service stations in the Denver metropolitan area each year.

Cost

Many stations, while not operating their Stage I equipment are equipped with it. Others would have to be retrofitted. The Minnesota Pollution Control Agency estimates that retrofitting a station will cost up to $15,000 per station, with a more typical cost of approximately $10,000 per station. This is a very reasonable cost for the emissions benefits that can be derived.

II: Description of how to implement:

Implementation of Stage I vapor recovery would be through State Implementation Plans. A state could also adopt such as a program as a state-only program if not part of a SIP. The state would enforce the requirements.

III. Feasibility of option:

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):

Low.

VI. Level of agreement within the workgroup for this mitigation option:

Good general agreement.

VII. Cross-over issues to other source groups:

There does not seem to be much cross over.

Mitigation Option: Stage Two Vapor Recovery and Vehicle On-board Refueling Vapor Recovery Systems

I. Description of the mitigation option:

Mandatory use of Stage-II vapor-recover systems as well as programs designed to maintain vehicle’s on-board refueling vapor recovery systems reduce evaporative emissions created during automobile refueling.

Automotive refueling is a major source of evaporative hydrocarbon emissions. As a vehicle’s gas tank is filled gasoline vapors in the tank’s headspace are displaced. It is estimated that when filling an empty 18-gallon fuel tank, 0.06 pounds of VOCs can be released (1,2), if such vapors are not captured by either a service station’s Stage II vapor-recovery system, or for newer vehicles, the vehicle’s on-board refueling vapor recovery system (this assumes that 30% of the vehicle’s gasoline tank’s headspace is composed of gasoline vapors and 70% by air) (2).

In a Stage II system, as an automobile is refueled, vapors displaced in the car’s gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station’s Stage I system when the underground tank is next refueled by the tank truck. The following illustration diagrams this.

Stage II Vapor Recovery System

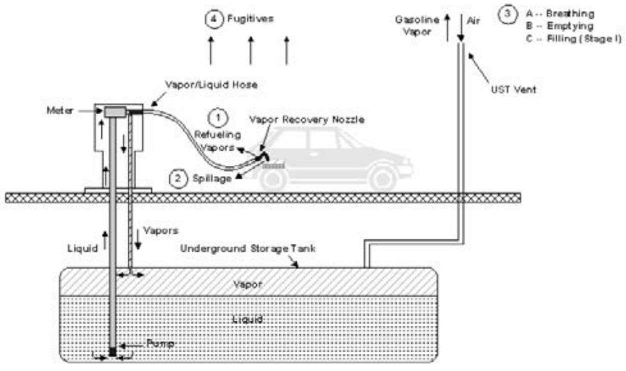
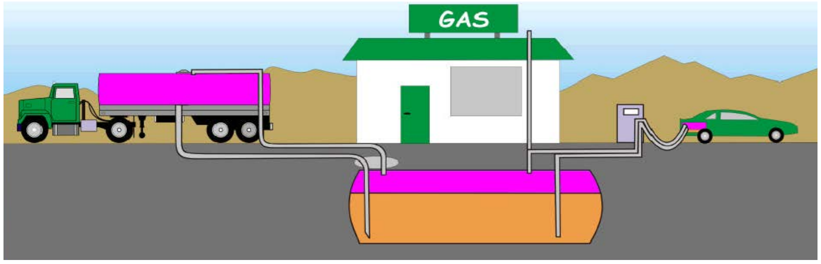


Figure 2. Controlled Stage II Process Operations with vapor recovery system.

Source: “Stage II Vapor Recovery Issue Paper”, U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

Another illustration also shows how Stage II works in conjunction with Stage I. Vapors from the automobile’s gasoline tank are routed back into the headspace of the station’s underground storage tank. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery’s or terminal’s vapor recovery system, where they are condensed back into liquid gasoline and reused.

Stage I & II Vapor Recovery Systems



Source: Calif. EPA, Nov.18, 2004

References:
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.
"Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

Air Quality Benefits of Stage II Vapor Recovery Systems

As part of its effort to reduce summertime ozone, many metropolitan areas across the nation with ozone concerns have adopted the use of Stage II vapor recovery systems at service stations. Stage II vapor recovery systems can be efficient. Depending on the frequency of inspection and equipment maintenance, up to 95%(1) of refueling vapors may be captured. In reducing VOCs, many air toxics, such as benzene and 1,3 butadiene are also reduced.

Modeling conducted by Mobiles Sources Program, Air Pollution Control Division, of the Colorado Department of Public Health and Environment, indicate that implementation of a Stage II vapor recovery program in the Denver Metropolitan area would reduce overall mobile source VOCs by 5.5% in the year 2007, and by 3.8% in the year 2012, when more vehicles are equipped with on-board vapor recovery systems.

On-board Refueling Vapor Recovery (ORVR) systems

On-board refueling vapor recovery (ORVR) systems work by routing escaping vapors from the fuel tank; through a charcoal canister that absorbs VOCs. The trapped VOCs are then pulled from the canister into the engine where they are burnt. ORVR systems have become standard equipment on light-duty automobiles beginning in 1998, and light duty trucks (trucks 1-2 starting in 2001, and trucks 3-4 in 2004).

As stated before, as the fleet penetration of on-board refueling vapor recovery systems increases, the emissions benefit from Stage II decreases somewhat. Currently, in the Denver metropolitan area, 54% of all gasoline motor vehicles now are equipped with on-board vapor recovery systems. As more of the fleet is equipped with on-board refueling vapor recovery systems, the effectiveness of Stage II is reduced. However, working together, they will both reduce refueling losses in the near to medium term, as shown in CDPHE's MOBILE6 modeling results. It should be pointed out that as ORVR systems deteriorate, refueling losses increase. At some point in the future, it may be necessary to implement some sort of inspection program to find and have fixed broken ORVR systems, maintaining the air quality benefits of these systems.

The U.S. EPA in their report “Stage II Vapor Recovery Issue Paper (August 12, 2004) includes a diagram (Figure 5, page 16 - shown below), of the refueling emissions trends for a hypothetical State. From inputs contributed by the American Petroleum Institute, this illustration shows four different scenarios; Stage II vapor recovery controls only (the blue line); on-board refueling vapor recovery only (the red line); Stage II vapor recovery controls with on-board refueling vapor recovery, where the ORVR interferes with the Stage II controls (the green line); and 4) Stage II vapor recovery controls and on-board refueling vapor recovery, where the ORVR does not interfere with the Stage II controls (the black line). The chart diagrams the years from 2005 through 2035 (1).

As seen in this diagram, a state with an existing Stage II vapor recovery program with an 85% effectiveness (blue line) will have a fraction of the refueling VOC emissions as a state that does not (the red line) in the year 2005. As more vehicles are equipped with ORVR systems, this advantage decreases, with at some point before 2015, the benefits of both control measures being equal. The blue line increases over time because of the increase in vehicle miles travels and does not include the effect of ORVR. However, before this time (2015), Stage II vapor recovery programs will give large benefits.

The other two scenarios shown represent decreasing VOCs over time with both control measures. There has been some research showing that Stage II can potentially interfere with on-board refueling vapor recovery systems. This is represented by the green line, where there is some increase in emissions as a result. However, all new Stage II systems certified by the state of California must show no interference with the ORVR. Using these approved systems, total VOCs are reduced for both Stage II and ORVR (the black line), where until 2025 there is a noticeable improvement having both systems.

Refueling Emissions Trends for Four Scenerios:

1) Stage II controls only (Blue Line), 2) On-board Refueling Vapor Recovery (ORVR) only (Red Line), 3) Stage II & ORVR with compatibility issues (Green Line), 4) Stage II & ORVR with no compatibility issues (Black Line)

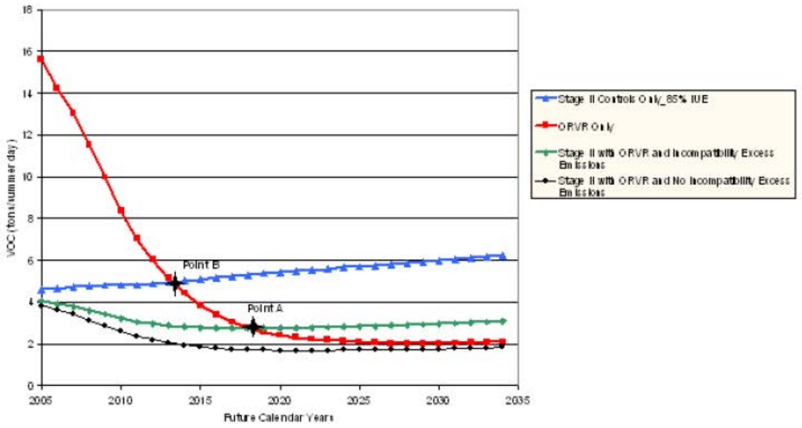


Figure 5. General emissions trends expected for refueling emissions in future calendar years for a hypothetical State (based on API studies).

Source: “Stage II Vapor Recovery Issue Paper”, U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

(1) “Stage II Vapor Recovery Issue Paper”, U.S. EPA, August 12, 2004.

Cost

There are costs to retrofit service stations with the necessary plumbing and equipment. In some cases this will be a major renovation to the station. Additionally, there will be on-going costs associated with operating and maintaining the Stage II vapor recovery system and equipment.

The state of New Hampshire, which has an operational Stage II vapor recovery program, estimates that the cost of Stage II installation at between $18,000 and $30,000 per station, depending on the station (1). They estimate on-going annual maintenance costs to be $1000 to $4000 per station yearly (1). Stage II requirements affect any station in that state that sells or has throughput of more than 420,000 gallons of gasoline annually (1).

(1) Environmental Fact Sheet, "New Hampshire's Gasoline Vapor Recovery Program - Protecting the Air We Breathe" New Hampshire Department of Environmental Services, 2004.

II: Description of how to implement:

Implementation of Stage II vapor recovery would be through State Implementation Plans. The state would enforce the requirements.

III. Feasibility of option:

This option is moderately hard to develop and implement. Gasoline service stations that are already plumbed for Stage II, and do not have to tear up concrete to put in vapor recovery plumbing are relatively easy to upgrade. Stations that need extensive work to install will be more difficult. Industry will not be supportive of this option.

IV. Background data and assumptions used

A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):

Low.

VI. Level of agreement within the workgroup for this mitigation option:

Good general agreement.

VII. Cross-over issues to other source groups:

There does not seem to be much cross over.

OTHER SOURCES: PUBLIC COMMENTS

Other Sources Public Comments

Comment	Mitigation Option
Dear Task Force Representative: I work for the Ute Mountain Tribe's Environmental Programs Department. We are about to partner with the EPA and the USGS to monitor radionuclides in the air and water around White Mesa, Utah where there is the only operating uranium mill in the nation. They are increasing production dramatically at the mill. We have significant concerns about radioactive dust blowing around out there. Any assistance that you or your staff could provide, funding if possible, would be a great thing. In the end we will have a publicly available, peer-reviewed report published by USGS and EPA. This could be a very important piece of the 4 corners air quality puzzle for you. My contact information is: Scott Clow, Water Quality Specialist, Ute Mountain Ute Tribe, PO Box 448, Towaoc, CO 81334, (970) 564-5431, scute@fone.net Thanks for considering this. Sincerely, Scott	
The last mitigation option makes me think that it is time to start considering regulating wood and coal burning stoves all-together. We have a tendency in the 4 corners to believe that we are small-fry, but continued urbanization is delivering us many big-city problems. In all, oil, gas and power plants tend to overshadow the cumulative impacts of residential activities. Our county governments should consider mitigation options accordingly.	
It is not enough to address the larger sources of air pollution in the Four Corners area. The efforts of this task force must also address the cumulative effects of the smaller sources.	
This is a great option. The Farmington/Aztec/Bloomfield area is an urban corridor, and the Durango/Bayfield area is quickly becoming so as well. We could easily reduce emissions and highway miles traveled if we were to expand upon park-and-ride systems (I believe I saw an ad for one between Ignacio and Durango) and also municipal transit.	Public Buy-in through Local Organizations to push for transportation alternatives and ordinances
Public outreach is great (often people are unaware of the health problems due to burning), but it may not reach the few and highly resistant people who burn regularly (both commercial and residential). As a resident, I would like to be able to call the sheriff and have enforcement that is effective (a fine, for example).	Develop Public Education and Outreach Campaign for Open Burning
The worst offending vehicles pass because their owners know how to beat the system on testing. Just enforce laws about taking cars off the road that visually are not in compliance. Add a tax based on engine size or exempt smaller engines and low weight vehicles.	Automobile Emissions Inspection Program
IM Programs will only work if all areas in that region are included. If they are not then owners of car will find ways to get around the program. Most of the owners that would do this are the owners of the cars that are the problem. Another way to make sure that your program is effective is to make sure that there is a assistance program for owners that can not afford to get their car emissions fixed.	Automobile Emissions Inspection Program

Comment	Mitigation Option
The IM programs will only be effective for our purposes if they are implemented in all areas. Also, the emissions programs for cars need stricter standards, thus making it economically infeasible to own larger engine, less efficient vehicles. There will always be those who find their way around the laws. However, if those laws are stricter, actually enforced, and applied throughout the Four Corners area then more problem vehicles will be taken off the road.	Automobile Emissions Inspection Program
On a voluntary basis, people could "adopt/subsidize" other vehicles that are not meeting emissions specs. Maybe this adoption could be tax deductible or a tax credit. How do we address the high emitting, newer vehicles (ie large trucks/cars)from the LEV (low emission vehicles)? Maybe a taxing structure would help both reduce the demand for new higher polluting vehicles, and help get high polluting older (the old "beater") vehicles off the road by helping to pay for their improvement/replacement.	Automobile Emissions Inspection Program
I would like City (and County if possible) ordinances to restrict idling. A rule that everyone follows will make it easier to get everyone on board the "no idling" plan. Public outreach also has to follow to teach people why idling causes problems and how "no idling" make make a difference. Signage at parking areas/unloading areas boat ramps, water filling stations/hydrants, the post office, grocery stores and other parking lots and etc. can remind drivers to turn off their engines.	Idle Ordinances
School bus retrofit--Let's do it! Then add public outreach to encourage more students to ride the bus, and we reduce emissions because the parents are not lined up in their cars to pick up/drop off their kids at school.	School Bus Retrofit
Though indirectly related to this topic, homes need to be upgraded weatherized and insulated so that we decrease the amount of fuel needed. Public outreach might help teach people how to build a clean fire. And people are burning trash in their wood stoves (similar to open burning). Coal is often used for heating and is particularly high in emissions, and seems to be equal to open burning.	Subsidy Program for Cleaner Residential Fuels

Energy Efficiency, Renewable Energy and Conservation

Energy Efficiency, Renewable Energy and Conservation: Preface

The Task Force identified a need for an Energy Efficiency, Renewable Energy, and Conservation (EEREC) mitigation option section for the Task Force report. Since this category had cross over among the groups, each group contributed to this section of the report. The Other Sources and Power Plants Work Groups met together at the November 8, 2006 Task Force meeting and briefly at the February 8, 2007 meeting to discuss EEREC as a topic. Louise Martinez, Bureau Chief of Energy Efficiency Programs with the New Mexico Energy, Minerals, and Natural Resources Department, gave a presentation on New Mexico Clean Energy Programs in the work group breakout session. New Mexico has a comprehensive set of renewable energy incentives to attract new projects and developers. The Four Corners area has a very strong solar energy resource and potential for energy efficiency improvements which both could offer environmental and health benefits.

Energy use is increasing in the Four Corners Area and in the U.S. as a whole. New generation will be required to meet additional energy demands. The work group on EEREC discussed that we could use the proactive NM position on clean energy as an example of a model to help write mitigation options for developing clean energy in the 4 Corners. Options focused on not only industry but also consumer behaviors. Three general areas were identified for options. Twenty-one mitigation options were brainstormed for the EEREC section; 18 were drafted.

Efficiency is important because efficiency is getting more out of each bit of energy we use. The result can be a direct benefit by reducing emissions from power plants or other sources and getting work done for less money. Efficiency has an indirect benefit by reducing the demand for additional energy production.

The work group brainstormed and drafted several options relating to efficiency. Options written included the following: Improved efficiency of home & industrial lighting; home audits for energy efficiency, as well as green building and energy efficiency incentives. An option was also written to improve county & city planning efforts. One option on power generation energy efficiency at existing power plants was written and included in the Existing Power Plants mitigation option section.

Renewable energy is important because it can benefit air quality by complementing and offsetting existing fossil fuel energy use and generation with clean energy sources. The work groups wrote options on better utilizing the solar resources in the Four Corners; expanding renewable portfolio standards to the Four Corners area municipalities and power cooperatives; creating/improving net-metering agreements with the electric utilities; and several others. A few policy options were written concerning importing and using only clean energy locally. One option tying together renewable energy and energy efficiency was written on “The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process.” An option discussing the viability of biomass as an energy source to mitigate air pollution was also drafted in addition to an option for a bioenergy center.

Conservation, or using less energy, is also important because it reduces air pollution. Burning fossil fuels directly or using electricity generated by fossil fuel combustion results in increased air pollutants. Decreasing energy consumption correlates to decreased emissions. Options focusing on conservation centered around energy use. Options that could improve conservation efforts and reduce emissions included smart metering, direct load control, time based pricing, and residential bill structure changes. The work group discussed the need for more education of the public & industry on these issues. An option for an “Outreach Campaign for Conservation & Wise Use of Energy” was drafted. The San Juan VISTAS program, a voluntary emissions reduction program emphasizing energy efficiency, was discussed as a possible model for all sectors of industry and the community to work together to improve air quality through cost effective strategies in the Four Corners area.

ENERGY EFFICIENCY

Mitigation Option: Advanced Metering

I. Description of the mitigation option

Overview

Advanced Metering is the integration of electronic communication into metering technology to facilitate two-way communication between the utility and the customer equipment. Increasing electric energy prices and a growing awareness of the need to reduce the environmental impact of electric energy consumption are directing the industry, legislators and regulators to turn to Advanced Metering technologies for solutions. Strategic deployment of Advanced Metering Systems will facilitate or enable sustainable and cost-effective Energy Efficiency (EE) and Demand Response (DR) programs while at the same time providing a platform for cost-reducing innovations in the areas of customer service, reliability, operations and business practices.

Partly due to the time lag between when energy is consumed and when the consumption is billed, and partly because there is no tangible commodity to associate with their monthly electric bill, most end-use customers have a difficult time relating their monthly electric bill with their daily energy use patterns. Consequently, a critical component of effective and sustainable EE and DR programs is the ability to provide energy use information to customers in an understandable, timely and useable manner. An Advanced Metering System with its two-way communication system provides an infrastructure for sending and receiving timely energy use and pricing information and, if desired, load control signals directly to customers and end-use equipment.

Advanced Metering Systems supports both EE and DR programs. The primary objective of EE programs is to reduce the total amount of energy used annually by consumers. (DR focuses on shifting energy use to off peak hours and does not necessarily result in energy conservation). EE programs, therefore, are typically focused on consumer education, the use of more energy efficient equipment and other measures such as building improvements to reduce energy losses and waste.

Environmental Benefits - Advanced metering provides indirect benefit to the environment by providing real-time tools to enable the customer to make informed decisions around energy use and conservation. Energy conservation displaces a portion of electric generation and can lead to lower emissions of carbon dioxide (CO2), nitrogen oxides (NOx), sulfur dioxide (SO2, and particulate matter (PM-10). In addition, reduced operation of generating plants means less water use and a reduction in the amount of natural resources (fossil fuels) being extracted from the earth. It can also help prevent or delay the need for building new power plants or other new energy infrastructure.

Economic- Direct operational benefits may result, including reduced monthly metering read costs; reduced meter read to billing time; reduced costs related to unaccounted for energy, energy diversion and energy theft; and reduced time to restore service following an outage.

Other benefits may include:

Increased customer satisfaction due to real time access to energy use information and other meter data by customer service personnel

Increased customer satisfaction due to the availability of accurate real time outage information and reduced outage times

The ability to apply innovative rate structures

Trade-offs - Capital costs to install Advanced Metering Systems can be more costly than conventional meters. Several years may be required for payback of Advanced Metering Systems.

II. Description of how to implement

Mandatory or Voluntary: Could be either voluntary or mandatory. Utilities have demonstrated that voluntary dynamic pricing programs can generate demand response and energy conservation. However, these programs tend to attract only modest levels of participation, in large part because they are narrowly targeted and passively marketed.

The public utility commission is the most appropriate entity to implement.

A differing opinion comment was received on this option during the Task Force Report Public Comment Period: “Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house ACs like that used in the Houston, TX area.” See the public comments received for EEREC in the appendix to this section.

III. Feasibility of the option

A. Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Advanced metering systems are commercially available.
B. Environmental: Medium feasibility. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours, but metering by itself does not save energy. Instead, metering should be viewed as a technology that enables optimized performance and energy efficiency, and provides the information necessary for customers to make more-informed decisions regarding their energy use.
Should energy conservation take place, air emissions, water and fossil fuel use can be reduced through generation displacement. Additionally, EE and DR programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.
C. Economics: Advanced metering systems must be designed, managed, and maintained to cost-effectively meet site specific needs. Applications analysis must consider both initial costs (i.e. purchase and installation) and on-going operations costs (e.g., data analysis, system maintenance, and resulting corrective actions).

IV. Background data and assumptions used

Gillingham, K., R. Newell, and K. Palmer, The Effectiveness and Cost of Energy Efficiency Programs, Resources Publication, Fall 2004, pgs. 22-25, www.rff.org/Documents

Federal Energy Regulatory Commission, Assessment of Demand Response and Advanced Metering, Staff Report, Dockett No. AD-06-2-000

Assumption: Regulatory rate structures that allow for decoupling profits from sales to remove disincentives to conservation.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option

Good. This option write-up stems from a discussion at the February 7, 2007 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Renewable Energy, Energy Efficiency and Conservation Mitigation Options

Mitigation Option: Cogeneration/Combined Heat and Power

I. Description of the mitigation option

Combined Heat and Power (CHP) is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers presented the CHP systems discussed herein include reciprocating engines, combustion or gas turbines, steam turbines, and microturbines.

These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling. When considering both thermal and electrical processes together, CHP typically requires only ¾ the primary energy separate heat and power systems require. This reduced primary fuel consumption is key to the environmental benefits of CHP, since burning the same fuel more efficiently means fewer emissions for the same level of output.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of CHP should be "voluntary" since the economics, operational aspects and emissions must be customized to the design objectives of the facility.
B. Indicate the most appropriate agency(ies) to implement**:** Since the option is voluntary and based upon the business decision of the entity proposing the facility, there is agency that would be in a position to mandate requiring CHP to be used. However, there could be a number of state agencies involved in permitting a CHP facility, including the state Air Quality Division, to issue air quality related construction and operating permits as appropriate.

III. Feasibility of the option

A. CHP Technologies

1. Gas turbines: are typically available in sizes ranging from 500 kW to 250 MW and can operate on a variety of fuels such as natural gas. Most gas turbines typically operate on gaseous fuel with liquid fuel as a back up. Gas turbines can be used in a variety of configurations including (1) simple cycle operation with a single gas turbine producing power only, (2) combined heat and power (CHP) operation with a single gas turbine coupled and a heat recovery exchanger and (3) combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to produce additional power using a steam turbine. Some combined cycles systems extract steam at an intermediate pressure for use and are combined cycle CHP systems. Many industrial and institutional facilities have successfully used gas turbines in CHP mode to generate power and thermal energy on-site. Gas turbines are well suited for CHP because their high-temperature exhaust can be used to generate process steam. Much of the gas turbine-based CHP capacity currently existing in the United States consists of large combined-cycle CHP systems that maximize power production for sale to the grid.

2. Microturbines, which are small electricity generators that can burn a wide variety of fuels including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines use the fuel to create high-speed rotation that turns an electrical generator to produce electricity. In CHP operation, a heat exchanger referred to as the exhaust gas heat exchanger, transfers thermal energy from the

microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses. Microturbines entered field-testing in 1997 and the first units began commercial service in 2000. Available and models under development typically range in sizes from 30 kW to 350 kW.

3. There are various types of reciprocating engines that can be used in CHP applications. Spark ignition (SI) and compression ignition (CI) are the most common types of reciprocating engines used in CHP-related projects. SI engines use spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI. Diesel engines, also called CI engines, are among the most efficient simple-cycle power generation options in the market. These engines operate on diesel fuel or heavy oil. Dual fuel engines, which are diesel compression ignition engines predominantly fueled by natural gas with a small amount of diesel pilot fuel, are also used. Higher speed diesel engines (1,200 rpm) are available up to 4 MW in size, while lower speed diesel engines (60 - 275 rpm) can be as large as 65 MW. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many instances, multiple reciprocating engine units can be used to enhance plant capacity and availability. Reciprocating engines are well suited for applications that require hot water or low-pressure steam.

4. Steam turbines that generate electricity from the heat (steam) produced in a boiler for CHP application. The energy produced in the boiler is transferred to the turbine through high-pressure steam that in turn powers the turbine and generator. This separation of functions enables steam turbines to operate with a variety of fuels including natural gas. The capacity of commercially available steam turbine typically ranges between 50 kW to over 250 MW. Although steam turbines are competitively priced compared to other prime movers, the costs of a complete boiler/steam turbine CHP system is relatively high on a per kW basis. This is because steam turbines are typically sized with low power to heat (P/H) ratios, and have high capital costs associated with the fuel and steam handling systems and the custom nature of most installations. Thus the ideal applications of steam turbine-based CHP systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use.

B. Environmental: CHP technologies offer significantly lower emissions rates per unit of energy generated compared to separate heat and power systems. The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) (unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. Similarly emissions of carbon dioxide are also dependent on the fuel used. Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x burners) that produce NO_x emissions ranging between 0.3 lbs/MWh to 2.5 lbs/MWh with no post combustion emissions control. Typically commercially available gas turbines have CO emissions rates ranging between 0.4 lbs/MWh – 0.9 lbs/MWh. Selective catalytic reduction (SCR) or catalytic combustion can further help to reduce NO_x emissions by 80 percent to 90 percent from the gas turbine exhaust and carbon-monoxide oxidation catalysts can help to reduce CO by approximately 90 percent. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve extremely low NO_x emissions.

Microturbines have the potential for low emissions. All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. The primary pollutants from microturbines include NO_x, CO, and unburned hydrocarbons. They also produce a negligible amount of SO_2.

Microturbines are designed to achieve low emissions at full load and emissions are often higher when operating at part load. Typical NO_x emissions for microturbine systems range between 0.5 lbs/MWh and 0.8 lbs/MWh. Additional NO_x emissions removal from catalytic combustion is microturbines is unlikely to be pursued in the near term because of the dry low NO_x technology and the low turbine inlet temperature. CO emissions rates for microturbines typically range between 0.3 lbs/MWh and 1.5 lbs/MWh.

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants from reciprocating engines are NO_x, CO, and VOCs. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. NO_x emissions from reciprocating engines typically range between 1.5 lbs/MWh to 44 lbs/MWh without any exhaust treatment. Use of an oxidation catalyst or a three way conversion process (non-selective catalytic reductions) could help to lower the emissions of NO_x, CO and VOCs by 80 percent to 90 percent. Lean burn engines also achieve lower emissions rates than rich burn engines.

Emissions from steam turbines depend on the fuel used in the boiler or other steam sources, boiler furnace combustion section design, operation, and exhaust cleanup systems. Boiler emissions include NO_x, SO_x, PM, and CO. The emissions rates in steam turbine depend largely on the type of fuel used in the boiler. Typical boiler emissions rates for NO_x with any postcombustion treatment range between 0.2 lbs/MWh and 1.24 lbs/mmBtu for coal, 0.22 lbs/mmBtu to 0.49 lbs/mmBtu for wood, 0.15 lbs/mmBtu to 0.37 lbs/mmBtu for fuel oil, and 0.03lbs/mmBtu – 0.28 lbs/mmBtu for natural gas. Uncontrolled CO emissions rates range between 0.02 lbs/mmBtu to 0.7 lbs/mmBtu for coal, approximately 0.06 lbs/mmBtu for wood, 0.03 lbs/mmBtu for fuel oil and 0.08 lbs/mmBtu for natural gas. A variety of commercially available combustion and post-combustion NO_x reduction techniques exist with selective catalytic reductions achieving reductions as high as 90 percent. SO_2 emissions from steam turbine depend largely on the sulfur content of the fuel used in the combustion process. SO_2 composes about 95% of the emitted sulfur and the remaining 5 percent are emitted as sulfur tri-oxide (SO_3). Flue gas desulphurization (FGD) is the most commonly used post-combustion SO_2 removal technology and is applicable to a broad range of different uses. FGD can provide up to 95 percent SO_2 removal.

While not considered a pollutant in the ordinary sense of directly affecting health, CO_2 emissions do result from the use the fossil fuel based CHP technologies. The amount of CO2 emitted in any of the CHP technologies discussed above depends on the fuel carbon content and the system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/mmBtu; oil is 48 lbs of carbon/mmBtu and ash-free coal is 66 lbs of carbon/mmBtu.

<u>C. Economic:</u> The total plant cost or installed cost for most CHP technologies consists of the total equipment cost plus installation labor and materials, engineering, project management, and financial carrying costs during the construction period. The cost of the basic technology package plus the costs for added systems needed for the particular application comprise the total equipment cost. Total installed costs for gas turbines, microturbines, reciprocating engines, and steam turbines are comparable. The total installed cost for typical gas turbines ranges from $785/kW to $1,780/kW while total installed costs for typical microturbines in grid-interconnected CHP applications may range anywhere from $1,339/kW to $2,516/kW. Commercially available natural gas spark-ignited engine gensets have total installed costs of $920/kW to $1,515/kW, and steam turbines have total installed costs ranging from $349/kW to $918/kW.

Non-fuel operation and maintenance (O&M) costs typically include routine inspections, scheduled overhauls, preventive maintenance, and operating labor. O&M costs are comparable for gas turbines, gas engine gensets, steam turbines and fuel cells, and only a fraction higher for microturbines. Total O&M costs range from $4.2/MWh to $9.6/MWh for typical gas turbines, from $9.3/MWh to $18.4/MWh for commercially available gas engine gensets and are typically less than $4/MWh for steam turbines. Based on manufacturers offer service contracts for specialized maintenance, the O&M costs for microturbines appear to be around $10/MWh.

IV. Background data and assumptions used

A. CHP offers energy and environmental benefits over electric-only and thermal-only systems in both central and distributed power generation applications. CHP systems have the potential for a wide range of applications and the higher efficiencies result in lower emissions than separate heat and power generation system. The advantages of CHP broadly include the following:

- The simultaneous production of useful thermal and electrical energy in CHP systems lead to increased fuel efficiency.
- CHP units can be strategically located at the point of energy use. Such onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, most of the members do not have technical experience working with CHP facilities.

Source of Information: Catalogue of CHP Technologies, U.S. Environmental Protection Agency, Combined Heat and Power Partnership

Mitigation Option: Green Building Incentives

I. Description of the mitigation option

This option involves the promotion of the Leadership in Energy Efficiency and Design certification LEED through state sponsored incentives. The LEED Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

The cost of LEED certification depends upon: the level of certification sought, the particular project demographics and characteristics, the availability of grants for achieving certification, the LEED experience of the Design Team, the LEED experience of the estimator, the stage in the design at which the Client makes the decision to seek certification (the earlier the better), and the Client's perception of the value and benefits of a more attractive building environment for their occupants. While the factors above may seem numerous, they are quantifiable, they can be priced, and they can be managed.

Certain aspects are realized at no additional cost due to the high level construction performance that today's contractors insist upon as standard practice. Clearly, the higher the certification level, the more it is required to accept the points that have significant additional cost impact. The strategy therefore is to firstly seek the points that have no financial impact, followed by either the insignificant premium costs or the insignificant additional costs. The expensive points are usually only sought when applying for Gold or Platinum certification.

II. Description of how to implement

A. Mandatory or voluntary: Because of concerns associated with the additional costs of certification, this program should be voluntary in scope. Yet, it should be mandatory for all new government buildings to be modeled after some of the options and foundations that this program is built upon, without necessarily reaching for LEED certification.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations,

III. Feasibility of the option

A. Technical: There are only two buildings with the highest LEED certification nation wide, although this certification is technically feasible. There are thousands of buildings build or retrofitted throughout the nation that initially use the guidelines and practices laid out in the LEED certification although they are not LEED certified.

B. Environmental: The environmental benefits of energy efficiency programs are very well documented.

C. Economic: This certification does increase the cost of construction through additional project management and supply demands. Although there are additional costs, the LEED certification does show economic benefits over the life of the building.

IV. Background data and assumptions used

<u>V. Any uncertainty associated with the option:</u> Medium

<u>VI. Level of agreement within the Work Group for this option</u>: TBD

Mitigation Option: Improved Efficiency of Home and Industrial Lighting

I. Description of the Mitigation Option

Utilizing compact fluorescent lights can result in significant energy savings when compared to traditional incandescent lights. Improved lighting efficiency in homes and in commercial/industrial business applications throughout the Four Corners States has tremendous potential to reduce energy consumption, save money, and reduce the amount of fuel burned in coal fired power plants. Burning less coal would result in fewer air pollution emissions.

One quote commonly used in news articles states "If every home in the U.S. switched one light bulb with an ENERGY STAR, we would save enough energy to light more than 2.5 million homes for a year and prevent greenhouse gases equivalent to the emissions of nearly 800,000 cars" (U.S. EPA, 2006).

Background:
Artificial lighting accounts for approximately 15 percent of the energy use in the average American home (U.S. DOE, 2006). Lighting consumes about 20 percent of all electricity used in the U.S. The nationwide lighting figure is potentially as high as 21-34 percent when the air conditioning needed to offset the heat produced by conventional lighting is considered (Rocky Mountain Institute, 2006).

Benefits: Energy Star qualified compact fluorescent light bulbs (CFLs) have many benefits including:

CFLs use 70 to 75 percent less energy than standard light bulbs (General Electric Company, 2006) with minimal loss of function. If the cost of the bulbs, lower energy use, and longer operating life are considered, a consumer can save approximately $52 over eight years for each CFL bulb that replaces a standard light bulb (Rocky Mountain Institute, 2004).

More than 90 percent of the energy used by incandescent lights is given off as heat, which creates the need run air conditioners to compensate for the heat generation and increases energy use (Rocky Mountain Institute, 2006). CFLs generate 70 percent less heat, reducing the need to cool interior air (US EPA, 2006).

CFLs commonly have an operating life of 6,000-15,000 hours compared to 750-1,500 hours for the average incandescent light (USDOE, 2006). CFLs last from 6-15 times longer.

At 4 mg of mercury per light, CFLs have the lowest mercury content of all lights containing mercury. All fluorescent lights contain mercury, incandescent lights do not. Use of CFLs results in a net reduction in mercury because coal power is such a large source of atmospheric mercury. The 70 percent lower energy consumption from CFLs compared to incandescent lights, results in a 36 percent mercury reduction into the atmosphere by coal-burning power plants. With proper recycling, the mercury released by CFLs decreases up to 76 percent compared to incandescent lights (US EPA, 2002; Rocky Mountain Institute, 2004).

Reduction in coal produced energy consumption would also result in a decrease of SOx, NOx, CO2, and other air pollution emissions. It can be demonstrated that running a 100-watt light bulb 24 hours a day for one year requires about 714 pounds of coal burned in a coal power generator. CFLs that use 70 to 75 percent less energy, would also translate from less power used, less coal burned, and fewer emissions. "Every CFL can prevent more than 450 pounds of emissions from a power plant over its lifetime" (U.S. EPA, 2006)

II. Description of how to implement

It has been determined that lack of awareness about the environmental benefits and energy/cost savings of CFL lights is the single largest barrier to their widespread use. CFL light replacement and education programs already exist in the U.S. and in other countries. Components of these programs were used in preparing this mitigation option.

Options could include any or all of the following:

States adopt the goal of delivering one free CFL bulb to every household in Colorado, New Mexico, Arizona, and Utah. Utilities, businesses, communities, and volunteers work together to deliver bulbs and information on the cost savings and environmental benefit of using CFLs.
Within the Four Corners States, adopt a campaign which includes regional advertising, information brochures, and marketing to promote awareness about the energy efficiency and environmental benefits of switching to CFL lights.
Provide light retailers with point-of-sale displays illustrating CFL cost savings, energy savings, proper CFL bulb selection, environmental benefits etc.
Offer State tax incentives for businesses/corporations that build or retrofit facilities using advanced lighting technologies including CFLs.

Voluntary or mandatory – The responsibility to develop a CFL light distribution and education program should be headed by the State governments of the Four Corners region. Coal power plants, utility companies, and other energy-related industry could voluntarily contribute to the purchase of CFL lights for distribution in households, and also contribute to educational awareness programs.

B. Indicate the most appropriate agency(ies) to implement – Colorado Department of Public Health and the Environment, New Mexico Environment Department, Utah Division of Air Quality, Arizona Department of Environmental Quality, DOE and EPA should take lead program roles. Certain aspects, such as purchasing lights for distribution, could be cooperatively funded by the Four Corners region coal-burning power plants, or State governments.

III. Feasibility of the Option

Technical: CFL technology is well developed and commonly available. In fact, large manufacturers of CFLs such as the General Electric Company and large distributors such as Walmart have embarked on major campaigns to promote and distribute CFL lights primarily for the “green” energy savings they represent (Fishman, 2006).

Environmental: Proven 70 percent reduction in energy consumption compared to traditional incandescent lights. Energy efficiency translates to reduction in air pollution emissions from coal-fired power plants. Lowest mercury content of all fluorescent lights, lower overall mercury emissions due to less coal based energy consumed.

Economic: Proven cost savings to consumers due to high energy efficiency and longer bulb life. If a 75 watt bulb is replaced by an 18 watt CFL bulb which is operated four hours a day, the estimated eight year savings is $36 - $52 (U.S. EPA, 2006, Rocky Mountain Institute, 2004). This calculation accounts for the higher purchase cost of CFLs.

IV. Background Data and Assumptions Used

(1) Fishman, Charles, 2006. How Many Lightbulbs Does it Take to Change the World? One. And You’re Looking at It. Fast Company Magazine, New York, NY.
www.fastcompany.com/magazine/108/open_lightbulbs.html

(2) General Electric Company, 2006. Ecomagination – For the Home: Compact Fluorescent Lighting. http://ge.ecomagination.com

(3) U.S. DOE, 2006. Energy Efficiency and Renewable Energy Consumers Guide: Lighting. http://www.eere.energy.gov/consumer/your_home/lighting

(4) U.S. EPA, 2006. Compact Fluorescent Light Bulbs: ENERGY STAR. Http://www.energystar.gov/

(5) U.S. EPA, 2002. Fact Sheet: Mercury in Compact Fluorescent Lamps (CFLs). www.nema.org/lamprecycle/epafactsheet-cfl.pdf

(6) Rocky Mountain Institute, 2006. Efficient Commercial/Industrial Lighting. http://www.rmi.org/sitepages/pid297.php

(7) Rocky Mountain Institute, 2004. Home Energy Briefs, #2 Lighting. http://www.rmi.org/

V. Any Uncertainty Associated With the Option

Low – both for feasibility and energy savings and environmental benefit through emissions reductions.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Volunteer Home Audits for Energy Efficiency

I. Description of the mitigation option
This option involves the development and implementation of a program or project that will engage community members in providing free energy audits to area residents. These audits of low income areas will find the largest sources of energy loss in homes and businesses and will provide simple solutions to the problem. Many local programs exist as examples, but currently only one program exists. Farmington had "make a difference day" at college, where they went to 10 homes with weatherization checklist. This could serve as a launching step for the program.

The air quality benefits to the region will be generated by increasing the energy efficiency of the homes and businesses involved in the program, therefore decreasing the amount of energy needed to be created by local coal burning power plants. In addition, those involved in the program can find out other sources by which to reduce their energy consumption (e.g. car pooling, appliance efficiencies).

II. Description of how to implement
A. Mandatory or voluntary: The audit of a home should be made mandatory for any individual or family receiving energy assistance from state or local governments and/or utilities. For those not receiving assistance, the program is voluntary in scope.

Weatherization and insulation subsidization: PNM has a good neighbor program; grants could go to non-profits; rebates could be used.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations, Americorps or Vista programs

III. Feasibility of the option
A. Technical: Similar programs are prevalent nationwide, this option is technically feasible.
B. Environmental: The environmental benefits of energy efficiency programs are documented.
C. Economic: Most energy efficiency programs, especially implemented with volunteers, are economically viable and sustainable.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the Work Group for this option All agreed.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process

I. Description of the mitigation option

In principle, facilities implementing activities that lead to energy efficiency (EE) and rely upon renewable energy (RE) can receive additional incentives/ flexibility in their State air quality permits. A goal would be to provide alternatives to conventional energy sources that occur within the nexus of environmental, energy, and economic activities. Such an effort would also allow EE/RE to compete with traditional pollution control technologies to reduce emissions and encourage more environmentally-sensitive energy generation.

The benefits to industry might include: categorical permit exemptions for specific source categories that incorporate EE and/or RE if their use result in significant ambient air quality improvements; use of EE/RE to represent offsets for the purpose of major source NSR review; education and promotion of EE/RE for the purpose of avoiding a permit requirement (i.e., reducing emissions below de minimus regulatory thresholds or “syn minoring”); incorporating EE/RE as a control option in the Reasonable Available Control Technology (RACT) review process for minor sources located in non-attainment and attainment/maintenance areas, and; other benefits as identified. State air quality agencies could also provide benefits to industry by considering: “fast tracking” environmental permit requests of facilities incorporating EE/RE; recognizing participating facilities through various environmental leadership awards’ programs; and, and other ideas as appropriate.

The benefits to the states could include: air quality improvements and help in avoiding future air quality problems; energy security; economic development (e.g., new jobs); environmental and energy leadership; facilitated collaboration between State and Federal agencies; and synergism of technical resources.

Such EE/RE approaches could be “codified” in State Implementation Plans, Supplemental Environmental Projects, and/or enforceable air pollution permits. EE/RE could also be tied to State Portfolio Standards (e.g., Colorado Renewable Energy Standards at 10% by year 2015) or other mechanisms.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary for industry to enter into EE/RE agreements, though possibly enforceable through State permits or SIPs.

B. B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies or other authorities responsible for issuing air quality permits; State Offices’ of Energy Management and Conservation (or like agencies); Department of Energy, if necessary in determining appropriate EE/RE initiatives;

III. Feasibility of the option

A. Technical: Technically, permitting agencies and interested industry would need to come up with a mutually satisfying definition of “EE/RE,” including possibly setting minimum EE/RE requirements. For example, EE/RE efforts might include: establishing/ continuing “green” programs such purchasing wind power to generate a significant percentage of energy to operate office buildings and facilities; incorporating solar power; expanding the use of alternative vehicles as vehicles of first choice in industry fleets; using biodiesel fuel use in fleet vehicles; encouraging other industry partners to adopt green programs and assist them with expertise and experience (peer to peer mentoring); using industry and State resources, combined with other resources, to educate employees and general public to EE/RE measures; and, exploring grants and other funding mechanisms for EE/RE efforts. Also, it would make sense to start this on a pilot level scale to resolve any challenges that are identified in an initial effort.

B. Environmental: It’s been demonstrated that there are direct environmental benefits from the use of EE and RE (e.g., reduced emissions of criteria and hazardous air pollutants, including SOx, NOx, mercury, etc.). Such EE/RE may also address concerns for impacts on regional haze and climate change.

C. Economic: EE/RE could be a significant financial gain for participating facilities in terms of: saved revenue from energy efficiency (“profits” could be re-directed to other aspects of the facility/industry); saved revenue by not having to transport fuels across the country, such as coal and heating oil; fuel price protection; reduced exposure to potential carbon taxation; an offset/trading value for early adopters and efficient reducers; public perception, and/or; others to be identified.

IV. Background data and assumptions used

Efforts would need to begin by establishing a workgroup with appropriate professionals who could illuminate opportunities to implement EE/RE through permitting and rule changes. Also, this initiative would need to work with permitting agencies’ inventory groups to collect data to identify source categories that may be appropriate pilot project candidates for an EE/RE initiative.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium, as there are not many examples to draw upon. Also, mutually satisfying definitions of EE/RE would need to be developed.

VI. Level of agreement within the work group for this mitigation option.

TBD but is assumed to be medium to high, depending on the workload necessary to get this effort underway.

VII. Cross-over issues to the other source groups TBD

RENEWABLE ENERGY

Mitigation Option: Expand the Renewable Portfolio Standards (RPS) to be Mandatory for Coops and Municipalities

I. Description of the mitigation option

The installation of new renewable generation has the potential to reduce the quantity of fuel combusted at existing fossil generation facilities thereby reducing air emissions and may potentially reduce the size of new generation that is needed to be built in the future.

Investor owned electric utility companies in New Mexico are required to provide 5% of the total energy supplied to its retail customers via renewable energy beginning in January of 2006. This requirement grows by 1% per year until 2011 when the requirement is l0%. This Renewable Portfolio Standard (RPS) requirement is part of the Rule 572 which was adopted by the NM Public Regulation Commission (NMPRC) in December of 2002. The New Mexico State legislature later passed the Renewable Energy Act, signed by the Governor on May 19, 2004, which codified this rule.

II. Description of how to implement

A. Mandatory or voluntary

The Renewable Energy Act states that the NMPRC may require that a rural electric cooperative 1) offer its retail customers a voluntary program for purchasing renewable energy under rates and terms that are approved by the NMPRC, but only to the extent that the cooperative's suppliers make renewable energy available under wholesale power contracts; and 2) report to the NMPRC the demand for renewable energy pursuant to a voluntary program. The Act is silent regarding municipalities at this time.

B. Indicate the most appropriate agency(ies) to implement

The NMPRC, the New Mexico Environment Dept, the New Mexico Energy, Minerals and Natural Resources Dept.

III. Feasibility of the option

A. Technical: Resource maps indicate that there is a good solar resource in the Four Corners area; however, wind energy, biomass, and geothermal are somewhat limited. Solar power generation is still more expensive than fossil-fired generation at this time.

B. Environmental: The environmental benefits of off-setting fossil-fired generation with renewable generation are well documented.

C. Economic: Each individual utility must balance it own unique needs to maintain a balance between reliability, environmental performance and cost. Integrating renewables into a utilities generation portfolio can cause electric prices to increase and adversely affect reliability to the utility's customers.

IV. Background data and assumptions used

Economic Outlook for Various Generation Technologies (2010)				
	Efficiency (%)	Capacity Factor (%)	Overnight Capital Cost(1) ($/kW)	Cost of Electricity (COE)(1) ($/MWh)
Wind (Class 3 to Class 6)(9)	N/A	30-42	1190	53-69

Solar Thermal (Parabolic Trough)	N/A	33	3410	180
Biomass CFB	28	85	2160	67
Coal(2) PC SC	39	80	1350	44
Coal(2) PC USC w/ CO2 capture	30	80	2270	72
Coal(2) CFB	36	80	1480	53
IGCC(2) GE – Quench W/O CO2 capture	37	80	1490	51
IGCC(2) GE – Quench w/ CO2 capture	30	80	1920	65
NGCC(4) (@ $4/MM Btu)	46	80(5)	500	43
NGCC(4) (@ $6/MM Btu)	46	80(5)	500	59
NGCC(4) (@ $8/MM Btu)	46	80(5)s	500	76

Acronyms: kW- kilowatts; MWh – megawatts/hour; CFB- circulating fluidized bed; PC- pulverized coal; SC-supercritical; USC- ultra-supercritical coal; IGCC- integrated gasification combined cycle; CFB- coal-fired boiler; NGCC- natural gas combined cycle

Notes:
All costs in 2006$; COE in levelized constant 2006$ and includes capital cost. Capital Cost is overnight, W/O Owner, AFUDC costs.
All fossil units about 600 MW capacity; Pittsburgh#8 coal for PC, CFB, IGCC.
Based on Gas Turbine technology limitations to handle hydrogen
NGCC unit based on GE 7F machine or equivalent by other vendors;
Represents technology capability
Value shown is 10% emission of total. The remainder is assumed to be absorbed by the biomass plant crop growth cycle
Includes reservoir development and associated cost for fuel supply
Reinjection of fluid in closed loop operation assumed
Wind COE values estimated via 2005 EPRI TAG analysis.

V. Any uncertainty associated with the option (Low, Medium, High)

High. Generally, the co-ops and municipalities do not like mandates.

VI. Level of agreement within the work group for this mitigation option

Mixed due to the fact that municipalities and rural electric cooperatives in the Four Corners area are relatively small and any participation in a statewide RPS will have a minimal impact on air quality.

VII. Cross-over issues to the other Task Force work groups None identified.

Mitigation Option: Four Corners States Adopt California Standards for Purchase of Clean Imported Energy

I. Description of the mitigation option

California has adopted a law that bans import of power from sources that generate more greenhouse gases than in-state natural gas plants. This law, which goes into effect January 1, 2007, impacts power generated in coal-fired plants in the Four Corners area, among others. Critics of this law say it will not accomplish its purpose of reducing emission of greenhouse gases, particularly carbon dioxide, because power from plants that do not meet CA's standards will simply be sold in other markets. If the Four Corners states (CO, NM, UT and AZ) adopted similar rules, pressure would be placed on the owners of many, if not all, the dirty plants in our area, plus a number of others, to clean up their emissions to meet the new standards. In so doing, a real contribution to the reduction of greenhouse gases, as well as other pollutants, would be made.

II. Description of how to implement

Four points relative to the CA legislation need to be addressed.

First, to be effective in a timely way, the rules need to apply to a utility's existing contracts that extend beyond a reasonable period of time, for example, five years. In anticipation of the January 1 implementation date for the CA law, some CA cities are renegotiating their long-term contracts, and extending them out to 2044. This must be avoided. Incentives will have to be provided to both sides in order to entice them to renegotiate their contracts

Second, some of the motivation for contract renegotiation relates to significant reductions in cost of power after the capital costs of the plant are retired. Incentives for renegotiation for similar reasons must be reduced or eliminated.

Third, state laws in the Four Corners area must specify power imported from 'other jurisdictions', such as from tribal nations as well as other states, in order to be effective in our area, since most present and future coal-fired power plants will be built on tribal lands, albeit within one of the Four Corners states. Additionally, tribal jurisdictions may wish to adopt similar legislation on the importation of power into their lands from external sources.

Fourth, the Four Corners states may not have a standard comparable to CA's standard, i.e., that of the greenhouse gas emissions of 'in-state natural gas plants'. In lieu of an appropriate in-state standard, a state could adopt CA's standard, or the average emission level for natural gas fired plants on a national level.

These requirements must be mandatory if they are to be effective

State and tribal permitting agencies should be given responsibility of implementation

III. Feasibility of the option

Technical - Four Corners states can seek technical assistance from the state of CA, which should be willing to assist in order to avoid dilution of the impact of their own law. Monitors of greenhouse gas emissions will need to be in place if not already in use

Environmental – This option would have a significant environmental impact

Economic – This option would also have a significant economic impact. There is no doubt that plants requiring significant pollution upgrades or even plant phase outs would raise the cost to shareholders and that these costs would be passed along to the customer. However, this is appropriate. End runs around the legislation, such as, marketing the power outside CA and the Four Corners area would occur to some extent. Obviously, addressing this issue at a national level would be far superior to a state-by-state approach; however, in lieu of national action, this option takes CA's step significant further.

Political – this option will be a very hard sell. Constituents in all Four States include citizens, including tribal members, with financial interests in status quo.

Legal – Since the U.S. Constitution gives Congress the power to regulate inter-state commerce, CA's law may not hold up to judicial scrutiny. If it doesn't, then this option would be withdrawn.

IV. Background data and assumptions

This option assumes legality, constitutionality and permanence of the CA law. This option would be withdrawn if the Supreme Court gives the EPA the power to regulate greenhouse gases in the case heard November 29 and if the EPA then takes a stance at least as tough as the CA standard.

V. Any uncertainty associated with the option

This option has lots of uncertainty related to political and legal feasibility.

VI. Level of agreement within the work group for this option TBD.

Mitigation Option: Net Metering for Four Corners Area

I. Description of the mitigation option

Providing electricity consumers in the Four Corners area with net-metering agreements would allow each consumer to generate their own electricity from renewable resources to offset their electricity use. A net-metering law also mandates that a utility cannot charge more for your electricity than they pay you for the solar(renewable) power you generate. Net metering would make small house/business renewable systems more feasible.

Increased capacity of renewable energy systems in the Four Corners and around the world, will lead to less need for new coal-fired power plants and their associated emissions

EPA has just released a new edition of its Emissions and Generation Integrated Resource Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. It contains emissions and emissions rates for NOx, SO2, CO2 and mercury. The database also contains fuel use and generation data.
In the United States, electricity is generated in many different ways, with a wide variation in environmental impact. Traditional methods of electricity production contribute to air quality problems and the risk of global climate change. With the advent of electric customer choice, many electricity customers can now choose the source of their electricity. In fact, you might now have the option of choosing cleaner, more environmentally friendly sources of energy. According to the EGRID Power Profiler, it is possible to generate a report, for example about City of Farmington electricity use. EGRID provides fuel mixes, i.e. how is our power being generated. For Farmington the mix is approximately 13% Hydroelectric, 13% gas, and 74% coal. E-GRID also provides the corresponding emissions rate estimates. For Farmington, emissions rates associated with the electricity generation (lbs/MWh) are 3.1 NO2, 3.3 SO2, and 1873 CO2

Info on E-GRID is available at http://www.epa.gov/cleanenergy/egrid

Net metering programs serve as an important incentive for consumer investment in renewable energy generation. Net metering enables customers to use their own electricity generation to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand. This offset means that customers receive retail prices for the excess electricity they generate. Without net metering, a second meter is usually installed to measure the electricity that flows back to the provider, with the provider purchasing the power at a rate much lower than the retail rate.Net Metering Policy:

Net metering is a low-cost, easily administered method of encouraging customer investment in renewable energy technologies. It increases the value of the electricity produced by renewable generation and allows customers to "bank" their energy and use it a different time than it is produced giving customers more flexibility and allowing them to maximize the value of their production. Providers may also benefit from net metering because when customers are producing electricity during peak periods, the system load factor is improved.

There are three reasons net metering is important. First, as increasing numbers of primarily residential customers install renewable energy systems in their homes, there needs to be a simple, standardized protocol for connecting their systems into the electricity grid that ensures safety and power quality. Second, many residential customers are not at home using electricity during the day when their systems are producing power, and net metering allows them to receive full value for the electricity they produce without installing expensive battery storage systems. Third, net metering provides a simple, inexpensive, and easily-administered mechanism for encouraging the use of renewable energy systems, which provide important local, national, and global benefits

History:
On September 30, 1999, the New Mexico Public Regulation Commission (PRC) adopted a rule requiring all utilities regulated by the PRC to offer net metering to customers with cogeneration (CHP) facilities and small power producers with systems up to 10 kilowatts (kW) in capacity. Municipal utilities, which are not regulated by the PRC, are exempt. There is no statewide cap on the number of systems eligible for net metering.

For any net excess generation (NEG) created by a customer, the utility must either (1) credit or pay the customer for the net energy supplied to the utility at the utility's "energy rate," or (2) credit the customer for the net kilowatt-hours of energy supplied to the utility. Unused credits are carried forward to the next month. If a customer with credits exits the system, the utility must pay the customer for any unused credits at the utility's "energy rate." Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity. [from DSIRE – Database of State Incentives for Renewable Energy – New Mexico]

Benefits:
Utilities benefit by avoiding the administrative and accounting costs of metering and purchasing the small amounts of excess electricity produced by these small-scale renewable generating facilities. Consumers benefit by getting greater value for some of the electricity they generate, by being able to interconnect with the utility using their existing utility meter, and by being able to interconnect using widely-accepted technical standards.

Tradeoffs: The main cost associated with net metering is indirect: the customer is buying less electricity from the utility, which means the utility is collecting less revenue from the customer. That's because any excess electricity that would have been sold to the utility at the wholesale or 'avoided cost' price is instead being used to offset electricity the customer would have purchased at the retail price. In most cases, the revenue loss is comparable to having the customer reducing electricity use by investing in energy efficiency measures, such as compact fluorescent lights and efficient appliances.

Special meters may also cost customer some installment costs

II. Description of how to implement

A. Mandatory or voluntary
Utilities should be required to providing Net metering arrangements for electricity users.

B. Indicate the most appropriate agency(ies) to implement
City of Farmington Utility, other Four Corners local utilities and Coops

Two comments were received on this option during the Task Force Report Public Comment Period:

“Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.”
“A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start-up program; this would have to come from state government programs for those who qualify.”

See all the public comments received for EEREC section in the appendix to this section.

III. Feasibility of the option

A. Technical

The standard kilowatt-hour meter used by the vast majority of residential and small commercial customers accurately registers the flow of electricity in either direction. This means the 'netting' process associated with net metering happens automatically-the meter spins forward (in the normal direction) when the consumer needs more electricity than is being produced, and spins backward when the consumer is producing more electricity than is needed in the house or building. [HP magazine, Net Metering FAQs]

It may be necessary to purchase a new meter.

B. Environmental

Use of renewable energy in the Four Corners area would offset emissions generated by polluting energy sources by approximately, 3.1 lbs NO_2, 3.3 lbs SO_2, and 1873 lbs CO_2 per MWh energy production.

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

C. Economic

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

Net-metering makes good economic sense. It is a fair approach and agreement between utility and consumer to buying and selling electricity

IV. Background data and assumptions used

1 Green Power Markets, Net Metering Policies
http://www.eere.energy.gov/greenpower/markets/netmetering.shtml

2 American Wind Energy Association: http://www.awea.org/faq/netbdef.html

3 Go Solar California Net Metering
http://www.gosolarcalifornia.ca.gov/solar101/net_metering.html

4 Database of State Incentives for Renewable Energy
http://dsireusa.org

5 Home Power Magazine, Net Metering FAQs:
http://www.homepower.com/resources/net_metering_faq.cfm

6. Solar Living Source Book, John Schaeffer, 2005

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Mitigation Option: New Programs to Promote Renewable Energy Including Tax Incentives

I. Description of the Mitigation Option

The Four Corners Region is recognized as having excellent solar and wind resources yet the incentives to use and develop renewable energy sources in Colorado (southwestern Colorado in particular) are extremely limited. For example, in Montezuma County, Colorado, net metering and the Federal Tax Credit for Solar Energy Systems are the only renewable energy incentives offered to residential power users. This mitigation option proposes several opportunities to diversify the incentives used to promote, develop, and increase the use of renewable energy in Colorado and other Four Corners states. The diversification of incentives will help Colorado in particular meet or exceed its current renewable energy standard (1), increase the overall use of renewable energy, reduce dependence on coal burning power sources, and reduce coal power plant emissions.

A 2003 report by the Union of Concerned Scientists gives "grades" to all states in the U.S. regarding the use and commitment to clean, renewable energy sources (2). Renewable energy sources include wind, geothermal, solar and bio-energy. In 2003, New Mexico received a grade "B+/B" (among the top 5 states in the nation) because of its commitment to increase the use of renewable energy by at least 0.5 percent per year. Currently, New Mexico has a renewable energy standard of 10 percent by the year 2011. In the same report, Colorado received a grade of "F" due to low levels of existing renewable energy and no commitment for future renewable energy development. This situation has improved since Colorado Amendment 37 passed in 2004 requiring a state-wide renewable energy standard. Colorado utilities are now required to obtain 3 percent of their electricity from renewable energy sources by 2007 and 10 percent by 2015. Even with the Colorado Amendment 37 law, incentives for encouraging the development of renewable energy in Colorado are extremely limited. There is tremendous opportunity to implement the many incentives already used in western states such as New Mexico, California and Nevada.

Incentives in this mitigation option would greatly accelerate the construction, maintenance, and expansion of solar and wind power generation. Wind and solar power sources create zero emissions of NOx, SOx, and CO2 (3). For this reason, solar and wind are the primary focus of this mitigation option.

INCENTIVES FOR RENERABLE ENERGY PROJECTS *

Incentive	**Description**	**Incentive Currently Offered?**		**Who Can Implement?**
		Colorado	**New Mexico**	**Authority**
Building Permit Fee Waiver for Solar Projects	Waive building permit fees when qualifying solar energy systems are installed in commercial/residential construction projects.	N	N	County/City
Leasing Solar Water Heating Systems	Service provider installs and maintains solar water heating systems for residents. Hardware owned and maintained by service provider. User pays installation fees and monthly utility fees based on system size.	N	N	Utility companies, city or county water & sanitation utilities
Renewable Energy Rebates/Credits	Rebates and/or credits (often based on system size) for purchase and	Only in a few areas,	N (?)	Utility companies

(System Costs)	installation costs of new grid-connected renewable energy systems that meet minimum energy efficiency qualifications.	including La Plata/Archuleta Counties.		
Renewable Energy Rebates/Credits (Net Metering)	Rebates and or credits for excess energy produced from grid-connected renewable energy systems.	Y	Y	Utility companies
Tax Deduction/Credit #1	Tax deduction or credit for 100% of the interest on loans made to purchase renewable energy systems or energy efficient products and appliances.	N	N	States
Tax Deduction/Credit #2	Property Tax deduction for qualifying solar photovoltaic systems.	N	N	States
Tax Deduction/Credit #3	Corporate income tax credit for companies with qualifying low or zero emissions renewable energy systems > 10 MW	N	Y	States
Tax Deduction/Credit #4	Personal income tax credit (plus Fed. Tax credit) up to 30% or $9,000 for on or off-grid photovoltaic and solar hot air systems.	N	Y	States
Sales tax exemption for Biomass Equipment and Materials	Commercial and industrial sales tax (compensating tax) exemption for 100% of the cost of material and equipment used to process biopower.	N	Y	States
Supplemental Energy Payments (SEP's)	SEPs are made for eligible renewable generators to offset above-market costs of investor-owned utilities to meet their renewable energy standard portfolio obligations.	N	N	States
Bond Programs for Public Buildings	Bonds provided to schools and public buildings to upgrade to energy efficient heating/lighting or installation of renewable energy power systems. Bonds paid back through savings on energy bills.	N	Y	States
Grant Programs	Grants provided for up to 50% of the cost of design, installation and purchase of renewable energy systems for residential and commercial/industrial	N	N	Utilities, States, residences
Energy Efficient Standards for State	Requirement for all new public building construction to achieve US	Only where economical	Y	States, local governments in

Buildings	Green Building Council Leadership in Energy and Environmental Design (LEED) ratings based on size. LEED systems emphasize energy efficiency and encourages use of renewable energy sources.	ly feasible		Colorado
Loan Programs	Zero interest loans offered for qualifying photovoltaic and solar water heat systems	Only a few locations, none in SW Colorado	N	Local communities, utilities and financial partners

* Incentives in this table were developed by comparing incentives currently used in New Mexico, California, Nevada, and Colorado (4)

Benefits: Incentives will be necessary to increase the use of renewable energy, especially for the typical residential power user. Colorado’s renewable energy program is relatively new and is stimulating a developing renewable energy market. The timing is very good to implement and support a diverse incentive program to meet or exceed the State’s renewable energy standard, and increase the overall use of renewable energy. An increased use of clean renewable energy will result in a corresponding decrease in NOx, SOx, and CO2 produced by coal-fired power generation.

Tradeoffs: Several incentive options would require legislation or other mechanisms of State governments and would require some time to set in place. Many incentives would be offered by State government in the form of tax incentives and may slightly decrease State tax revenues. The use of incentives listed in the above table by several western states is a good indication they work effectively and provide value to that State. They can be implemented by Colorado and other Four Corners region states.

II. Description of How to Implement

A. Voluntary or mandatory – Incentives, by definition, would be voluntary for the consumer. It could be voluntary or mandatory for the States, local government, or utility companies to offer the incentives.

B. Indicate the most appropriate agency(ies) to implement – See Incentives Table above for appropriate agency for each incentive measure.

III. Feasibility of the Option

Public and corporate knowledge regarding the environmental benefits and cost benefits of solar and wind alternative energy systems is limited, and could be greatly improved. The diversification of incentives could stimulate interest in renewable energy systems.

A. Technical: The technology for wind and solar power systems, and solar water heating and space heating is currently widely available. Improvements to make these technologies more efficient and affordable is ongoing. Using incentives to increase the use and demand for these systems would stimulate further technological advances.

B. Environmental: A 10 percent increase in the use of renewable energy in Colorado will result in a reduction of 3 million metric tons of CO2 per year in 25 years (5). It would also result in the reduction of SO2 and NOx.

C. Economic: 1) Increased demand and use of solar and wind energy systems will stimulate accelerated improvements in solar and wind energy technology and reduce costs of the technology in the long term. 2) Implementing incentives for individuals and corporate/businesses will stimulate and accelerate the use of existing wind and solar technologies. 3) Increased use through incentives will create an expanding market for producers (6), and could create up to 2,000 new jobs in Colorado in manufacturing, construction, operation, and maintenance and other industries in 25 years (5) 4) Increased use of the technology would reduce and energy costs to consumers and insulate the economy from fossil fuel price spikes (7).

IV. Background Data and Assumptions Used

(1) A renewable energy (or electricity) standard is a requirement by a state or the Federal government for utilities to gradually increase the portion of electricity they produce from renewable energy sources.

(2) Union of Concerned Scientists, 2003. Plugging in Renewable Energy, Grading the States. www.ucsusa.org/clean_energy

(3) American Wind Energy Association, 2006. Wind Energy Fact Sheet – Comparative Air Emissions of Wind and Other Fuels. 122 C Street, Washington, D.C., 2 pp.; citation for solar).

(4) Database of State Incentives for Renewable Energy (DSIRE), 2006. New Mexico, Colorado, Nevada, and California Incentives for Renewables and Efficiency. www.dsireusa.org/ ; Governor's Office of Energy Management and Conservation, 2006. Rebuild Colorado, Utility Incentives for Efficiency Improvements and Renewable Energy. www.colorado.gov/rebuildco ; Martinez, Louise, 2006. Presentation to the Four Corners Task Force – New Mexico Clean Energy Programs. New Mexico Energy, Minerals, and Natural Resource Department, presentation in Farmington NM, November 8.

(5) Union of Concerned Scientists, 2004. The Colorado Renewable Energy Standard Ballot Initiative: Impacts on Jobs and the Economy. www.ucsusa.org/clean_energy/clean_energy_policies/the-colorado-renewable-energy-standard-ballot-initiative.html

(6) Gielecki, Mark, F. Mayes, and L. Prete, 2001. Incentives, Mandates, and Government Programs for Promoting Renewable Energy. Department of Energy, 26 pgs. www.eia.doe.gov/cneaf/solar.renewables/rea_issues/incent.html

(7) Union of Concerned Scientists, 2006. Renewable Energy Standards at Work in the States. http://www.ucsusa.org/clean_energy_policies/res-at-work-in-the-states.html

V. Any Uncertainty Associated With the Option (Low, Medium, High)

Low – Increasing the use of renewable energy sources is widely accepted as a practice which will decrease air pollution emissions associated with burning fossil fuels. Increasing incentives would increase the widespread use of renewable energy systems.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Promote Solar Electrical Energy Production

I. Description of the mitigation option

A. Promote Solar Electrical Energy Production:
The region in general has good solar energy possibilities, a large number of clear days with very few successive days of clouds. If storage was not used it means that there would be power to feed to the distribution system during peak solar intensity. The power density is also quite favorable being in the range of 600 to1000 W/m2 for peak values (winter, summer). In the summer this would match the large load of air-conditioning, it would not match the winter load. Solar electrical has a developed technology with standards and while the systems are complex, especially if feedback to the power grid is done, it is not beyond the capabilities of trained people in the area.
B. Reduce Electrical Energy Consumption by Substituting Solar Energy:
The reduction of electrical energy consumption for home heating and hot water production can be replaced or supplemented by solar energy inputs. These would be significant for the individual household but these households are a small percentage of the general population. All buildings use solar energy, it is just a matter of degree. All can be improved to make better use of the solar energy which we have available, reducing other energy consumption.

II. Description of how to implement

A. Mandatory or voluntary:
Voluntary on the part of the person with the solar electric installation and with agreement of the electric utilities company, possibly with legal control by the state. Utilities would specify interconnect requirements.
B. Indicate the most appropriate agency(ies) to implement
Utilities/State

III. Feasibility of the option

A. Technical: For solar electrical systems, new inspectors would be needed or present ones reeducated. You may need a change in distribution control system.
B. Environmental: The environmental results of shifting the energy consumption from fuels (gas, oil, coal) burned in the region to solar means a reduction of all types of air pollutants by what ever reduction was achieved.
C. Economic: Not that practical unless the person is far off the grid. Would most likely need incentives (tax?). Large capital out lay to replace ongoing expenses of fuel. If other energy sources are replaced by solar, taxes will be lost.
D. Political: Since regulation and taxes may be involved this could be a problem.

IV. Background data and assumptions used:

6000-7000 heating degree days for the region
1500 cooling degree days for the region
6 usable solar hours per day (yearly average).
5 usable solar hours per day (winter average)

V. Uncertainty associated with the option (Low, Medium, High):

Low for would it work, High for could you get enough people doing it to have a significant affect.

VI. Level of agreement within the Work Group for this option TBD

VII. Cross-over issues to the other source groups None

Mitigation Option: Subsidization of Land Required to Develop Renewable Energy

I. Description of the mitigation option

Land required for larger renewable energy projects, especially solar electric energy production, would be subsidized. This option would help to promote and make renewable energy production more feasible.

BLM/FS has a large amount of unused land. Some large renewable energy projects could be demonstrated on that land. A collaborative program should be developed with US Government owners of NW NM land to provide cheap or in some case potentially free land leases to companies that are willing to develop renewable energy production facilities. Barriers should be reduced.

The Navajo Nation and other tribes in the Four Corners area own a large amount of land in the Four Corners area. There has been some interest in wind energy development on Native American land in Arizona. Available land resources on the reservation could be used to develop renewable energy projects and stimulate the local economy.

Benefits: Solar electric energy is clean energy.
Solar electric energy production could complement and eventually displace coal fired power plant electricity generation. Eventually, over time, promotion and expansion of solar electric energy production could replace the need for a new coal-fired power plant. This alternative strategy to energy production would then displace the air pollution emissions associated with that power plant.

Solar electric energy development in the Four Corners area would stimulate the photovoltaic equipment and service industry here.

Burdens: Land resource would be needed (see feasibility section). We have estimated the amount of land required to generate 1 MW of solar electric capacity.

II. Description of how to implement

A. Mandatory or voluntary
Mandatory. A rule would need to be created describing the subsidization amount and conditions.

B. Indicate the most appropriate agency(ies) to implement
Four Corners government property owners such as BLM, FS, and Navajo Nation

III. Feasibility of the option

A. Technical
The amount of land required to produce 1 MW solar electric generation capacity

For Farmington, NM a Flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees avg. of 6.3 hours of full sun. Full sun is 1,000 watts per square meter.

For our estimation we will use large Evergreen Cedar-series ES-190 W Spruce Line Module with MC Connectors, rated by California Energy Commission, http://www.consumerenergycenter.org/cgi-bin/eligible_pvmodules.cgi, at 166.8 watts output.

Based on our location in Farmington, 166.8 watts x 6.3 hours, we have a per day 1050 watt-hr per day per module. Module is approximately 61.8” x 37.5”, surface area is 16.1 square feet. Allow extra space and we will need approximately 20 square feet per module.

Assume DC output to conventional AC power conversion inefficiency of 95%, CEC

1.05 KWh per module per day is reduced to approx 1 KWh at AC grid.

Conversion: 43,560 square feet in an acre
2178 modules could be fit on area of 1 acre.
This # of PV modules would generate approximately 2.2 MWh of energy.
At Farmington site this corresponds to approximately 345 KW of solar electric generation capacity.

Therefore, we could fit could generate 1 MW of electricity during daylight hours on about 3 acres of land in Farmington. Based on the solar irradiance values for Farmington this would be about 2.2 MWh of energy per day.

[Real Goods Solar Living Sourcebook, John Schaeffer, 12th edition, 2005, p.57 method of design used]

B. Environmental: Photovoltaic modules do not have significant negative environmental costs

C. Economic: Each module in example would cost approximately $1,000. There is a large amount of open land available, not in use, on government land in the 4 Corners area. Renewable energy projects could provide local jobs and help economy.

IV. Background data and assumptions used

1. California Energy Commission, http://www.energy.ca.gov/, PV specifications
2. Evergreen Solar PV module product information, http://www.evergreensolar.com/
3. Farmington, NM Solar Insolation data from San Juan College Renewable Energy Program

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Use of Distributed Energy

I. Description of the mitigation option

Distributed energy refers to decentralized generation and use of relatively small amounts of power, usually on demand in a local setting. Excess power may or may not be delivered to the grid. This option would encourage the use of distributed energy by owners of residential or commercial buildings or neighborhoods, where practical and feasible. While it is generally accepted that centralized electric power plants will remain the major source of electric power supply for the future, distributed energy resources (DER) can complement central power by providing incremental capacity to the utility grid or to an end user. Installing DER at or near the end user can also benefit the electric utility by avoiding or reducing the cost of construction of new plants to meet peak demand and/or of transmission and distribution system upgrades.

Distributed energy encompasses a wide range of different types of technologies. The Department of Energy, the state of California and various trade groups have programs encouraging research into and use of these technologies. Distributed energy technologies are usually installed for many different reasons. This option focuses on any distributed energy options that reduce demand on grid sources and thereby reduce the demand for new large power plants and/or transmission costs. While excess power generated by distributed sources and delivered to the grid can aid in reduction of power demand on centralized sources, distributed energy options are also important in serving needs in areas not currently attached to the grid thereby reducing the need for hookup to the grid.

Since these technologies are individual and/or local in nature, the burden would be on the prospective homeowner and building owner to seek out options and financing and a contractor who is sufficiently knowledgeable to suggest options and skilled enough to implement them. Initially, mortgage support or grants may also be needed to encourage implementation.

For the environmentally conscious consumer, the use of renewable distributed energy generation and "green power" such as wind, photovoltaic, geothermal or hydroelectric power, can provide a significant environmental benefit. However, the potential lower cost, higher service reliability, high power quality, increased energy efficiency, and energy independence are additional reasons for interest in DER.

II. Description of how to implement

The choice to use distributed energy resources and specifically which one(s) are appropriate should be voluntary. The decision can involve higher capital costs, and the willingness to invest in technologies that may be new and not widely implemented. Federal, state and local departments of energy should support research into options most suited to a particular geography and climate; loans and grants should be available and experts should be retained to consult with potential users.

III. Feasibility of the option

A. Technical – Information on various choices is available, choices range from low-tech to high-tech
B. Environmental – Any options that reduce the demand on the centralized power grid and minimize their own pollution will contribute to an improved environment by reducing the need for coal-fired power plants in our area
C. Economic – Options range in cost. Greater use of options should ultimately result in reduced unit costs
D. Political – Use of distributed energy resources should be an easy sell politically; the degree to which federal and state research and resources are already available, indicates a public commitment already in place

IV. Background data and assumptions N/A

V. Uncertainty – This option has a high degree of certainty that it could be implemented and be effective.

VI. Level of agreement within the work group for this option TBD

VII. Cross-over issues to the other source groups None at this time.

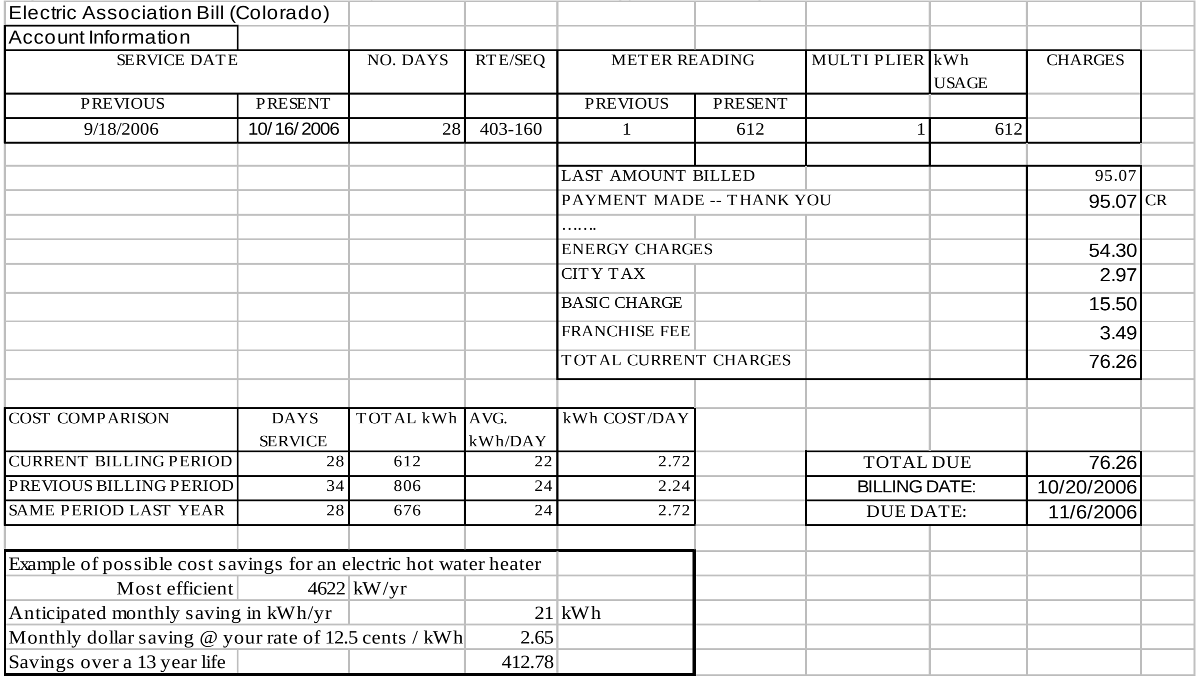
CONSERVATION

Mitigation Option: Changes to Residential Energy Bills

I. Description of the mitigation option

Energy for many households in the four corners area is delivered as electricity and/or natural gas. Residential energy is used for home heating, hot water, and to run appliances. Most residential consumer receives monthly bills. Examples of typical electric and gas bills are shown in Figures 1 and 2, respectively.

Figure 1. Residential electric utility bill with sample energy cost savings



Electric Association Bill (Colorado)									
Account Information									
SERVICE DATE		NO. DAYS	RTE/SEQ	METER READING		MULTI PLIER	kWh USAGE	CHARGES	
PREVIOUS	PRESENT			PREVIOUS	PRESENT				
9/18/2006	10/16/2006	28	403-160	1	612	1	612		
				LAST AMOUNT BILLED				95.07	
				PAYMENT MADE -- THANK YOU				95.07	CR
				…….					
				ENERGY CHARGES				54.30	
				CITY TAX				2.97	
				BASIC CHARGE				15.50	
				FRANCHISE FEE				3.49	
				TOTAL CURRENT CHARGES				76.26	
COST COMPARISON	DAYS SERVICE	TOTAL kWh	AVG. kWh/DAY	kWh COST/DAY					
CURRENT BILLING PERIOD	28	612	22	2.72		TOTAL DUE		76.26	
PREVIOUS BILLING PERIOD	34	806	24	2.24		BILLING DATE:		10/20/2006	
SAME PERIOD LAST YEAR	28	676	24	2.72		DUE DATE:		11/6/2006	
Example of possible cost savings for an electric hot water heater									
Most efficient	4622	kW/yr							
Anticipated monthly saving in kWh/yr			21	kWh					
Monthly dollar saving @ your rate of 12.5 cents / kWh			2.65						
Savings over a 13 year life			412.78						

Figure 2. Residential gas utility bill with sample energy cost savings

Energy (gas) Company Bill (Colorado)

BILLING INFORMATION:		
METER DEPOSIT	347.00	
PREVIOUS BALANCE		
CURRENT GAS CHARGE TOTAL		85.15
FACILITY CHARGE	21.50	
COM LDC COST @ .16000/CCF	12.45	
UPSTREAM COST @ .02530/CCF	1.97	
COMMODITY COST @ .67930/CCF	52.86	
DEFERRED GAS COST @ -.09880/CCF	-7.69	
FRANCHISE FEE @ .05000	4.06	
SERVICE CHARGE TOTAL		0.54
PENALTY	0.54	
TAX TOTAL		
STATE TAX @ .02900	2.47	
CITY TAX @ .04050	3.44	
COUNTY TAX @ .00450	0.38	
CURRENT CHARGES		91.98
TOTAL AMOUNT DUE		91.98

DATE OF SERVICE		METER READING	
FROM	TO	PREVIOUS	PRESENT
10/02/06	11/01/06	9750	9845

RATE CODE:	36QC
USAGE IN CCF:	78
PRESSURE FACTOR:	0.819

Usage this month	95	therms
Example of possible cost savings for a gas hot water heater		
Most efficient	230	therms/year
Anticipated monthly saving in therms	4	kWh
Monthly dollar saving @ your rate of 0.97 cents	3.88	
Savings over a 13 year life	605.28	

A typical energy bills lists meter readings, cost breakdowns, and other technical information. Much of the information on monthly energy statements is required by regulatory bodies and laws. Most importantly, a typical bill does not provide the consumer with information to make decisions on energy conservation and the ability to translate proposed conservation options to dollars saved.

The suggested mitigation option is to have an additional place on monthly bill that would feature one energy conservation step that a consumer may take and indicate cost savings. In the examples presented, a cost saving for a new energy efficient hot water heater is shown (bold box in Figure 1 and in Figure 2). Another monthly statement could show the amount of savings that may result from lowering the thermostat one degree Fahrenheit. A statement of energy saving on the bill would be more effective that simply including a generic insert in the bill. These often are quickly discarded.

In addition, we recommend that all energy bills have a graph that shows 1) year to month energy used for the current and past year and monthly use comparing the current to the previous year.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement:
Energy companies

III. Feasibility of the option

A. Technical: Some reprogramming of residential energy billing program
B. Environmental:
C. Economic: Cost of reprogramming software

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other Task Force work groups: Unknown

Mitigation Option: County Planning of High Density Living as Opposed to Dispersed Homes throughout the County

I. Description of the mitigation option

San Juan County is presently starting the process of developing a county wide growth master plan. A number of questions in their citizens questionnaire were if there should be encouragement or restrictions in development of home sites in the rural areas of the county and if this growth should be low or high house value. From the point of view of energy conservation and hence reduced pollution of many types the county should be encouraged to develop a plan which encourages clustering of housing (not in the far rural areas) so as to reduce energy losses on distribution lines and the reduction of travel distances for transportation. The ideal clustering should be near employment and services. Other counties in the Four Corners should be encouraged to also follow this pattern.

II. Description of How to Implement:

A. Mandatory or voluntary
While you cannot force people to do this, encouragement by tax policies, varying rates based on distances for electrical services, zoning or other methods would be helpful.
B. Indicate the most appropriate agency(ies) to implement

Taxes and zoning would be under the county government while the rates would be with the electric utilities companies of allowed by law. I do not know how much latitude they have.

III. Feasibility of the option

A. Technical: No problems

B. Environmental: None until specifics are assumed.

C. Economic: Concentrated populations, within limits, will have an advantage of reduced infrastructure coast.

D. Political: The greatest problem with this option will be general resistance to the ideal by the general public and very great resistance from those with vested interest.

IV. Background data and assumptions used San Juan county citizens' questionnaire.

V. Uncertainty associated with the option (Low, Medium, High) TBD.

VI. Level of agreement within the Work Group for this option TBD.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Direct Load Control and Time-based Pricing

I. Description of the mitigation option

Overview
This option describes demand response tools focused on direct load control and electric pricing. By offering direct load control and electric pricing options around time-of-day, critical peak and seasonal use, customers are provided with an effective price signal regarding when and how they use electricity. Demand response ("DR") is the label currently given to programs that reduce customer loads during critical periods. In the past, DR programs have also been called "load management" and "demand-side management" programs. Most demand response programs currently focus on either peak load clipping through direct load control or load shifting through time-based pricing mechanisms. The primary goal of DR programs is to reduce peak demand. The concerns regarding impending major capital expenditures by utilities for additional generating and transmission system capacity and the impact of energy consumption on the environment has sparked a renewed interest in utility programs to reduce the amount of energy used during periods when the generation and power delivery infrastructures are most constrained and at their highest costs. Reductions in peak demand may or may not be accompanied by a reduction in the total amount of energy consumed. This is because DR programs may result in energy consumption simply being shifted to a period when the utility system is not as constrained and market prices are lower.

Air Quality and Environmental Benefits- Demand response programs primary purpose is to reduce peak load. These programs may not lead to energy conservation nor should they be relied upon to do so (Energy efficiency programs are specifically designed to reduce the total amount of energy used by customers on an annual basis).
These programs may allow utilities to hold off on building new generating plants and permit technology to develop and mature in the areas of clean coal generation as well as renewable energy.
(As an indirect benefit, if customers do choose to conserve energy, the reduction in energy use may lead to a reduction in the need for energy generation resulting in emission reductions in air pollution and greenhouse gases).

Economic: Customer charge for the installation and use of automatic metering systems (where applicable) installed in participating residential and commercial customer homes and businesses
Cost to utility for administration and tracking of the program.

Trade-offs: Positive public relations, clean coal and renewable technology maturation

II. Description of how to implement

Mandatory or voluntary: Voluntary
Time of use pricing: Electricity is priced at two different levels depending upon the time of day. The inverted block rate is a rate design for a customer class for which the unit charge for electricity increases from one block to another as usage increases and exceeds the first block. The incentive is to use less energy and stay within the first block, which has the lowest rates.

Critical peak pricing: Critical peak pricing is a pricing scheme that encourages customers to reduce their on and mid-peak energy usage by offering incentives through an alert-based, monitoring system.

Seasonal use pricing: Electric rates vary depending upon the time of year. Charges are typically higher in the summer months when demand is greater and the cost to generate electricity is higher. For example, during the months of June through September, electricity rates would be higher than other months.

The public utility commission is the most appropriate entity to implement.

III. Feasibility of the option

Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Automated and advanced metering systems are commercially available.

Environmental: Medium feasibility for indirect benefits. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours. This may or may not lead to energy conservation. However, such programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.

Economic: Good economics. Advanced metering systems, in addition to better enabling time-based rates, can deliver load control signals to end-use equipment and provide consumers with energy consumption and price information to assist with shifting load from on-peak to off-peak periods, thereby saving the customer money on their utility bills. Direct load control and electric pricing options create long-term market transformations by shifting energy use to periods of lower plant and infrastructure constraints as well as lower market cost. As a result, utility maintenance and equipment replacement costs may be reduced and the cost to build new generation may also be postponed.

IV. Background data and assumptions used

Energy Administration Information, Department of Energy

Federal Energy Regulatory Commission, "Assessment of Demand Response & Advanced Metering"

Conservation is not the purpose of direct load control and electric pricing options. Energy efficiency programs are better suited to promote conservation.

V. Any uncertainty associated with the option (Low, Medium, High) Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option Good. This option write-up stems from a discussion at the November 8, 2006 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Pilot Neighborhood Project to Change Behavior to Reduce Energy Use and Energy Efficiency Programs

Mitigation Option: Energy Conservation by Energy Utility Customers

I. Description of the mitigation option

This option would require all generators of power (renewable and non-renewable sources) in the Four Corners area to develop a program which causes their customer base to reduce per capita power usage each year for five years until an agreed upon endpoint is reached. The owners of all facilities that generate power, irrespective of how it is generated, should be required to develop or participate in a program which encourages their customer base to reduce per capita, per household, per production unit (or whatever other measure is equivalent for non-residential customers) use of power each year for five years until some reasonably aggressive endpoint is reached. The percent annual reduction would be 20% of the difference between the baseline usage and the five year goal.

The goal or endpoint would be negotiated between industry trade groups, governmental agencies, environmental groups and interested parties and would vary depending on the climate at the location of the customer base. The set of endpoints thus determined would apply industry-wide and always be a challenge. Most measures observed to date depend on a percent reduction in per unit usage. The difference in this option is that the endpoint for each customer base is a specific achievable minimum amount of energy usage based on current technology.

This concept is similar to water conservation programs, which have successfully reduced water usage. Water companies have used incentives to promote the use of water saving devices – low water flush toilets, controls on shower heads, more efficient outdoor sprinkling systems.

Power generators could develop their own programs or join together with other power producers in a consortium to implement a program. Customers could be rewarded with financial incentives such as reduced costs per unit for reduced levels of usage and/or lesser rates for power used at off-peak times of the day or week. Conservation credits could be traded as in the pollution credit trading program as long as the caps were reduced each year until the overall goal for that customer base is met.

A web site devoted to success and failure of conservation incentive programs, publicizing the progress of each power plant could impact compliance by affecting shareholder decisions, among other things. The American Council for an Energy Efficient Economy has a start on this with their study ‘Exemplary Utility-Funded Low-Income Energy Efficiency Programs’ (www.aceee.org).

The burden of this requirement would be on the power generators and indirectly on the customer base. The goals for each power generating plant should be aggressive but attainable for their customer base. When a plant has multiple customer bases, appropriate goals should be set for each base separately, in consideration of differences in climate.

II. Description of how to implement

This rule should be mandatory for all power generators. Many power generators have such programs now but should be required to look at best practices (most cost-effective programs) for these programs and implement them.

A loan-incentive program may be needed to help owners of large buildings replace costly appliances such as hot water heaters, refrigerators, heating and air conditioning units, which can achieve high energy savings.

III. Feasibility of the option

Technical: Programs motivating conservation exist.

Environmental: The environmental benefits include reduced pollution which accompanies reduced power generation relative to what it would have been either at peak times or over time, depending on success of customer conservation program. Over time fewer power generating facilities would need to be built (or older inefficient units could be retired sooner)
Economic: Programs will cost money, but they are cost-effective (see data below). Implementation could be contracted out
Political: Probably minimal challenge in getting this requirement passed, this is pretty innocuous; and the public relations campaign around conservation would educate consumers as to their role and potential impact on reducing greenhouse gases, reducing air pollution and improving air quality

IV. Background data and assumptions

(1) Southwest Energy Efficiency Project (SWEEP): Highlights taken from SWEEP's website, http://www.swenergy.org/factsheets/index.html:

The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest examines the potential for and benefits from increasing the efficiency of electricity use in the southwest states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. [Unfortunately, California is not included.] The study models two scenarios, a "business as usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and workplaces during 2003-2020.

Major regional benefits of pursuing the High Efficiency Scenario include:

- Reducing average electricity demand growth from 2.6 percent per year in the Base Scenario to 0.7 percent per year in the High Efficiency Scenario;
- Reducing total electricity consumption 18 percent (41,400 GWh/yr) by 2010 and 33 percent (99,000 GWh/yr) by 2020;
- Eliminating the need to construct thirty-four 500 megawatt power plants or their equivalent by 2020;
- Saving consumers and businesses $28 billion net between 2003-2020, or about $4,800 per current household in the region;
- Increasing regional employment by 58,400 jobs (about 0.45 percent) and regional personal income by $1.34 billion per year by 2020;
- Saving 25 billion gallons of water per year by 2010 and nearly 62 billion gallons per year by 2020; and
- Reducing carbon dioxide emissions, the main gas contributing to human-induced global warming, by 13 percent in 2010 and 26 percent in 2020, relative to the emissions of the Base Scenario.

These significant benefits can be achieved with a total investment of nearly $9 billion in efficiency measures during 2003-2020 (2000 $). The total economic benefit during this period is estimated to be about $37 billion, meaning the benefit-cost ratio is about 4.2. The efficiency measures on average would have a cost of $0.02 per kWh saved.

The High Efficiency Scenario is based on the accelerated adoption of cost-effective energy efficiency measures, including more efficient appliances and air conditioning systems, more efficient lamps and other lighting devices, more efficient design and construction of new homes and commercial buildings, efficiency improvements in motor systems, and greater efficiency in other devices and processes used by industry. These measures are all commercially available but underutilized today. Accelerated adoption of these measures cannot eliminate all the electricity demand growth anticipated by 2020 in the Base Scenario, but it can eliminate most of it.

(2) US Department of Energy – Energy Efficiency and Renewable Energy, a consumer's guide: http://www.eere.energy.gov/consumer/ List of suggestions for consumers includes many of the items mentioned in SWEEP's High Efficiency Scenario and focuses on proper operation of the items.

V. Uncertainty

No uncertainty about benefits of conservation; moderate uncertainty about how much consumers will cooperate and actually conserve.

VI. Level of agreement TBD.

VII. Cross-over issues

Need discussion as to how it would fit into Oil and Gas Group's sources

Mitigation Option: Outreach Campaign for Conservation and Wise Use of Energy Use of Energy

I. Description of the mitigation option

Conservation is an important strategy for mitigation air pollution in 4 Corners area. An outreach campaign centered on this strategy would help to educate public and industry and lead to more conservation actions. This would lead to a sustainable future, reduce dependence on fossil fuels, and help to mitigate air pollution in the Four Corners area.

Conservation is defined as the sustainable use and protection of natural resources including plants, animals, minerals, soils, clean water, clean air, and fossil fuels such as coal, petroleum, and natural gas. Conservation makes economic and ecological sense. There is a global need to increase energy conservation and increase the use of renewable energy resources.

Coal fired power plants are the nation's largest industrial source of the pollutants that cause acid rain, mercury poisoning in lakes and rivers and global warming. Utilizing renewable energy sources such as wind and solar and improving energy efficiency in appliances, business equipment, homes, buildings, etc. will theoretically reduce pollution from coal fired power plants. Of course, installation of best management pollution control equipment on existing coal fired power plants will be most beneficial.

Renewable energy alternatives such as solar, water, and wind power and geothermal energy are efficient and practical but are underutilized because of the availability of relatively inexpensive nonrenewable fossil fuels in developed countries. Conservation conflicts arise due to the growing human population and the desire to maintain or raise the standards of living.

Up until now, consumer behavior has been motivated by cheap and plentiful energy and not much thought has been given to the degradation of the environment. Production and use of fossil fuels damage the environment. The supply of nonrenewable fossil fuels is limited and is rapidly being used up. Fossil fuel is becoming more expensive. Reality is beginning to set in. There is a need for safe, clean energy production, renewable energy alternatives, and conservation. Energy supplies and costs will restructure consumer usage.

Federal and State agencies and the utility companies need to focus on more public awareness and provide information on available tax credits for solar, photovoltaic, and solar thermal systems. There are also tax credits available to homeowners for replacement of older air conditioners, heat pumps, water heaters, windows, and installation of insulation. There are tax incentives for the purchase of hybrid automobiles.

All of this information is available on web sites, tax forms, agency handouts, etc. but, more than likely, the average citizen is unaware. Since alternative energy and conservation have moved to the forefront, the public needs information. Public service announcements on TV, radio and newspapers and informational mailings in consumer energy billings would be most helpful.

School children should be included in the energy information process. There is a program for grades K - 4 titled "Energy for Children - All about the Conservation of Energy" with a teacher's guide that is available on www.libraryvideo.com.

The educational programs need to start in elementary school (or earlier) and continue through high school. There are some really great opportunities for curriculum development in energy conservation that would integrate several disciplines including biology, math, and social studies. I think NM has done the best job of this among the four corner states and hope that it will be expanded to the other states. It would be good just to have a group review K-12 materials, see what gaps exist and how information, including successes can be promulgated. Perhaps this has been done - a web site is a good start.

A Google search of "conservation of energy resources" has a very large website database.

Volunteer groups are working to improve the energy efficiency of homes occupied by the elderly and by people who are unable and/or cannot afford to make home improvements.
Communities could work toward increasing the volunteer workforces and the resources for this much needed humanitarian service.

The future belongs to our children and grandchildren. What we have done in the past and what we do in the here and now, has a direct impact on the environment that future generations will inherit.

II. Description of how to implement

A. Mandatory or voluntary
Voluntary at grassroots and governmental levels
Some mandatory curriculum could be developed for schools as part of educational component

B. Indicate the most appropriate agency(ies) to implement
Local Governmental Energy and Air Quality Agencies. Schools

III. Feasibility of the option

A. Technical: We must clearly demonstrate the problems and potential solutions

B. Environmental: Conservation has been shown to reduce energy use

C. Economic: Outreach program must demonstrate the short term economic benefits. Also design program to benefit low-income citizens. Government needs to provide some economic incentives to help kick start conservation programs

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups All Work Groups.

CROSSOVER OPTIONS

Mitigation Option: Bioenergy Center
(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Biomass Power Generation
(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Utility-Scale Photovoltaic Plants
(Reference as is from Power Plants: see Future Power Plants section)

ENERGY EFFICIENCY, RENEWABLE ENERGY AND CONSERVATION: PUBLIC COMMENTS

Energy Efficiency / Renewable Energy / Energy Conservation Public Comments

Comment	Mitigation Option
Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house AC's like that used in the Houston, TX area.	Advanced Metering
Using combined heat and power could be an effective method to increase efficiency and reduce emissions.	Cogeneration/Combined Heat and Power
The Four Corners region has a huge potential to develop renewable energy resources. Moreover, our resources are not limited to good sun and the region's many windy plateaus. Our citizenry possesses a large body of technical expertise, many of whom already work in energy and electrical power generation. We also have mechanical expertise and a pre-existing industrial infrastructure at our hands. Last, we are extremely well-suited to implement educational programs for renewable energies. Dineh College, San Juan College, and Fort Lewis College are obvious examples. This option can also sustain us beyond the inevitable decline in oil and gas production, as well as providing a means for younger generations to stay and work in their home areas (which is especially problematic in La Plata County.) Last, this possibility fits neatly with the previous recommendation for a regional planning board or authority. In short, we have every reason in the world implement renewable energy as a regional industry.	Renewable Energy
Pure protectionism, not good energy policy. The NIMBY attitude will never solve problems. If you want clean energy, do it the right way, build nuclear. I notice that this option never came up why?	Four Corners States Adopt California Standards for Purchase of Clean Imported Energy
Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.	Net Metering for Four Corners Area
A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start up program; this would have to come from state government programs for those who qualify.	Net Metering for Four Corners Area

Cumulative Effects

Cumulative Effects: Preface

Overview

The Cumulative Effects work group was charged with assisting the source work groups to understand current and future air quality conditions in the region, using existing information. The cumulative effects workgroup was also to assist the other work groups in performing their analysis of the mitigation strategies being developed, within the scope of the Task Force's timeframe and resources. The Cumulative Effects work group was also tasked with suggesting ways for filling technical gaps and addressing uncertainties as identified by the other work groups.

The Cumulative Effects work group was a small group with approximately a half dozen active members representing state governments, tribal governments, local citizens, industry, and the federal government.

Scope of Work

The following was the original scope of work for the Cumulative Effects (CE) work group.

Specific Tasks:

1. Evaluate air quality effects of candidate mitigation measures as requested by other Task Force work groups, or provide guidance on how candidate mitigation measures could be evaluated.
2. Prepare overarching cumulative estimate of the air quality effects from implementation of all the Task Force recommended mitigation measures.
3. Describe a "gold standard" for the best technical analyses that can be done, and provide recommendations for future analyses. Describe the uncertainty associated with the air quality estimates.
4. Respond to issues referred to the CE work group from other work groups.
5. Recommend additional analysis, studies, etc. that may be necessary for the CE work group to fully carry out its tasks. For example, the CE may feel that it is necessary to conduct an ozone precursor field study with advice from the monitoring group, or an ammonium field study for particulate matter.

Discussion

In accomplishing #1, the Cumulative Effects work group was charged with assessing upwards of 20 of the numerous mitigation options being proposed by the source-related work groups. For these options, the emissions reductions associated with undertaking the mitigation approach have been estimated. In addition, the work group also detailed methods, assumptions, limitations, and sources of information.

All of the tasks associated with estimating emissions reductions were relative to the oil and gas sector. In order to make much of this work as accurate as possible, the Cumulative Effects work group undertook improvements to the base case inventory for drilling and production activities in the Four Corners region. The base case inventory shows what current and future emissions would be in the absence of additional air pollution mitigation. The best data from the Western Regional Air Partnership (WRAP), the States of New Mexico and Colorado, the Southern Ute Indian Tribe, and industry participants were consolidated and quality assured to create a more accurate and complete inventory than previously existed. Using estimates of the effectiveness of the various mitigation options and applying them to the base case, estimates of the number of tons of pollution that would be reduced by each mitigation option were calculated. Emissions reductions associated with mitigation options directed and motor vehicles used in oil and gas activities were also estimated.

Because of the length of time and resources required to set up modeling analyses and to accomplish them, the modeling task (#2) was moved outside the Task Force process. It will inform regulatory agencies of the air quality benefits of options after the Task Force report is completed. The approach taken is akin to the “gold standard,” and thus #3 was addressed as part of the agencies’ modeling effort.

Consistent with #4, the Cumulative Effects work group also responded to requests for additional information relative to a few of mitigation options, for example, answering questions about monitoring at a power plant and providing a bit more detailed description of overall emissions.

Related to #5, suggestions for future research associated with implementation of the mitigation options are presented, for example, with regard to the sources and impacts of ammonia emissions and the economic effect of various mitigation option

OVERVIEW OF WORK PERFORMED

The Cumulative Effects (CE) work group was requested to provide information on a number of mitigation options described by the source work groups. Table 1 summarizes the reasons why the Cumulative Effects work group may or may not have researched a particular question, and a brief description of the outcome if work was performed.

Table 1: Summary of mitigation option findings.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Tax or Economic Incentives for Environmental Mitigation	CE did not have expertise to address this option.	No action.
Selective Catalytic Reduction (SCR) on Drilling Rig Engines	There was insufficient time to address this option.	Some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed.[1]
Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards for Drilling Rigs	There was insufficient time to address this topic.	An important piece of information is that these engines typically last 4-10 years and then need to be replaced. This means that there will be a constant infusion of new technology engines over time. However, faster turnover would reduce emissions in the near-term.
Industry Collaboration for RICE	This option was not evaluated because it is not possible to quantify emission reductions.	No action.
Install Electric Compression for RICE	This option was evaluated.	Replacement of low emission engines with electric power grid would result in an overall increase in emissions. A reduction in NOx emissions would occur, however, there would be an increase greenhouse gas emissions due to increased electrical generation requirements.
Follow EPA Proposed New Source Performance Standards (NSPS) for RICE	This option was evaluated.	This proposed emission standard will become the baseline for new modified and reconstructed engines. Future year projections indicate that these standards will minimize growth in oil and gas emissions from natural gas fired engines.
Install Selective Catalytic Reduction (SCR) on Lean Burn Engines for RICE	This option was evaluated.	There is very little information on the installation of this control technology on natural gas fired engines. What is available indicates that in the Four Corners area the installation of this technology would result in small NOx reductions. In addition, the cost to control emissions would be relatively high.[2] **Differing Opinion:** Disagree with the last two sentences.
Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE	This option was evaluated.	It was found that installation of NSCR on small engines could reduce NOx emissions significantly. The USEPA performance standard for rich burn engines will likely require installation of NSCR for new, modified and reconstructed rich burn engines.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Install Lean Burn Engines for RICE	This option was evaluated.	Emission inventory data indicated that on large engines of greater than 500 horsepower this technology or NSCR is already being used on the majority of the engines in the region. The use of these engines results in significant reductions in NOx over the use of rich burn engines, and may be beneficial when applied to smaller engines.
Install Selective Non Catalytic Reduction (SNCR) for RICE	This option was evaluated.	It was determined that this technology is unlikely to be used because it is less effective than SCR or NSCR.
Install Oxidation Catalyst on Lean Burn Engines for RICE	This option was evaluated.	This mitigation option was evaluated in terms of HAPs emissions and VOCs. Previous modeling analyses indicated that HAPs impacts are localized. It was found that VOC emission reductions would be primarily methane and ethane which have a low photochemical reactivity, and likely do not contribute to ozone formation. **Differing opinion:** Contest the previous statement as to accuracy. Methane is a greenhouse gas and reduction of methane emissions is desirable in combating global climate change.
Install Optimized/Centralized Compression	This option was evaluated.	It was concluded that there would be no opportunities for reducing emissions as a result of implementing this option.
Next Generation Control Technology for RICE	This option was evaluated.	Because these technologies are emerging, it is not possible to quantify the additional benefits of controls.
Automation of Wells to Reduce Truck Traffic	This option was evaluated.	Potential fugitive dust emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Centralized Produced Water	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Efficient Routing of Water Trucks	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Cover Lease Roads with Rock or Gravel	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Enforcing Speed Limits on Dirt Roads	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Selective Catalytic Reduction (SCR) NOx Control Retrofit	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Emissions Monitoring for Proposed desert Rock Energy Facility to be Used Over Time	This option was assessed.	The option was looked at by the CE Work Group, and an assessment included.
Declining Cap and Trade Program for NOx Emissions for Existing and Proposed Power Plants	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Chronic Respiratory Disease Study for the Four Corners Area	A brief look at the data was done.	A summary of ozone trends generally showed an upward trend. Another look at this question will be provided by future work.
Install Electric Compression	This option was evaluated.	See above.

Emissions Summary

The overall emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC) broken into broad source categories can provide some perspective when reductions from various mitigation options are presented in subsequent sections. Table 2 shows the relative importance of groups of sources in the Four Corners region:

Table 2: Percentage of total future year emissions in 2018 by pollutant.

SOURCES	NOx EMISSIONS (%)	VOC EMISSIONS (%)
Mobile	2	5
Area	1	23
Oil & Gas	26	32
Power Plants	40	1
Other Point Sources	30	39

This table demonstrates that oil and gas production, electrical generation, and other industrial activities are the largest emitters of nitrogen oxides, while oil and gas production, industrial facilities other than those related to power plants and oil and gas production, and area sources emit the majority of VOC. Area sources are those industrial and commercial activities that are small enough to not be required to obtain an air quality permit to operate. Area sources also include a broad range of human activities that result in small amounts of pollution on an individual basis.

The data presented in Table 1 have been derived primarily from the Western Regional Air Partnership (WRAP) emission inventory. For these categories, the Four Corners Air Quality Task Force requested an extraction from the WRAP regional database for the Four Corners area that encompasses portions of Colorado, New Mexico, Arizona, and Utah. The one exception is for oil and gas sources, which were estimated using updated information developed by the Cumulative Effects work group.

Emissions Reduction Summary

Table 3 summarizes emission reductions for mitigation options for which the estimates were made in order to facilitate comparison. Some estimates were made by the Cumulative Effects work group for the Oil and Gas work group, while some were made by the Power Plants (PP) work group for their own options. Descriptions of the mitigation options and how the estimates were derived can be found in the section of each work group, respectively.

Table 3: Mitigation Option Summary

Mitigation Option	Work Performed By	Pollutant Reduced	Reduction Estimate (tpy)
Control Technology Options for Four Corners Power Plant	PP	NOx	11,688
Control Technology Option for San Juan Generating Sta.	PP	NOx	6,166
Enhanced SO2 Scrubbing	PP	SO2	2,083
Selective Catalytic Reduction (SCR) NOx Control Retrofit	PP	NOx	29,987 to 46,684
BOC LoTOx System for Control of NOx Emissions	PP	NOx	43,257
Baghouse Particulate Control Benefit	PP	PM10	465
Declining Cap and Trade Program for NOx Emissions	PP	NOx	3,428
Install Electric Compression w/ Grid Power	CE	NOX & SO2	Variable – See note below
Install Electric Compression w/ Onsite Gen Power	CE	NOX & SO2	12,000 to 40,721
Use of NSCR for NOx Control on Rich Burn Engines	CE	NOx	16,588 to 21,327
Use of SCR for NOx Control on Lean Burn Engines	CE	NOx	Insufficient information to quantify
NSPS Regulations	CE	NOx	0
Optimization/Centralization	CE	NOx	0
Use of Oxidation Catalyst for Formaldehyde & VOC Control on Lean Burn Engines	CE	VOC	1619
Automation of Wells to Reduce Truck Traffic	CE	PM10 & NOx	196 & 92
Reduced Truck Traffic by Centralizing Produced Water Storage	CE	PM10	39
Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks	CE	PM10	196
Reduced Vehicular Dust Protection by Covering Lease Roads with Rock or Gravel	CE	PM10	206
Reduced Vehicular Dust Production by Enforcing Speed Limits	CE	PM10	73

Note: Some engine configurations are as efficient as current coal-fired generating stations without being subject to line losses, whereas other engines would be less efficient than using commercially available line power.

Suggestions for Future Work

As the Cumulative Effects work group completed the tasks of evaluating mitigation options, it became clear that there is a need for future work to provide regulatory agencies additional information on the benefits of reducing pollution emissions into the air in the Four Corners region. Additional detailed modeling is planned by the agencies that will provide more refined information regarding the actual effects of proposed mitigation programs. The modeling analysis is scheduled for completion in the fall of 2007. Leading into the analysis of mitigation programs, some updating of source information will be necessary. An example would be for drilling rigs.

To supplement the modeling analyses, additional monitoring of pollutants and meteorology throughout the Four Corners region would be useful. This monitoring would provide a basis for establishing whether model predictions are accurate and would help determine air quality trends. Currently, there are relatively few air monitoring sites in the Four Corners region to use in testing model performance. Monitoring for ammonia would be particularly useful as it enhances the ability of the model to estimate the effects of air pollutant emissions on visibility.

The Cumulative Effects work group was required to delve into agency emissions inventories in detail, and this work exposed many weaknesses in state and tribal inventories. For future analysis of options, it is recommended that states and tribes require more robust reporting of industrial entities, including reporting of facilities that may currently fall below permitting or reporting thresholds. States and tribes may require regulatory changes to reporting requirements to accomplish this. Lack of detailed reported data introduces a high level of uncertainty into analysis of options for mitigation. State and tribal agencies need to be able to quantify cumulative reductions with certainty in order to appropriately evaluate and prioritize options. By performing analyses that combine trends in emissions with trends in monitoring data, information may be identified regarding source receptor relationships.

The work group also recommends a review of existing field test data and an expansion of the existing state and tribal field testing programs for source emissions. Improvement of inventory emissions estimates will result in better modeled estimates of air pollution concentrations. A focused effort to obtain and share emissions data from a variety of oil and gas engines under different operating conditions would be particularly beneficial in inventory improvement.

Finally, the work group recommends that economic analysis of options be conducted to provide cost/benefit information to state and tribal agencies. The work group did not have the time or resources to conduct economic modeling, but economic data is of great importance in analyzing and prioritizing options. Such modeling could analyze “bundled” options to minimize analysis costs.

Endnotes:

[1] Personal communication between Reid Smith (BP) and David Finley (WDEQ).

[2] EPA Speciate data for natural gas-fired engines.

DETAILED DESCRIPTIONS OF MITIGATION OPTION ANALYSES

Mitigation Option: Install Electric Compression with Grid Power

Description of Option

Under this option, existing or new natural gas fired internal combustion engines would be replaced with electric motors for powering compressors. Electric motors would be selected to deliver equal horsepower to that of the internal combustion engines being replaced.

Assumptions

It is assumed that electricity to power the electric motors would come from the existing electrical grid. The majority of the base load electricity in the region is produced from coal-fired electrical generation.

This option did not consider the installation of natural gas electrical generation systems, which would have entirely different emissions characteristics from coal-fired electrical generation. In this approach, small high-emission natural-gas engines would be replaced by electric motors driven by a larger low-emission natural-gas engine. Although natural gas fired generators have not been used in the region, the feasibility for possible future use should be investigated. [1]

In evaluating the changes in emissions for shifting from natural gas to electric (coal) powered compression, it is necessary to examine the emissions for each power source on an equivalent energy basis. Thus, for the same amount of energy consumption, the change in emissions from natural gas versus electricity must be considered.

In the evaluation of this mitigation option, it is not appropriate to consider emission modifications to existing electrical generating facilities. While such modifications may occur or new lower emitting facilities may be developed, the inclusion of such changes in emissions are speculative at this point in time. The emission data was developed using the EPA program EGRID. [2]

In this analysis, it was assumed that for visibility SO2 and NOx emissions are equivalent in terms of impacts because they cause approximately the same amount of visibility impairment. This is because the dry scattering coefficients for converting SO4 and NO3 concentrations into visual range are approximately equivalent. NOx emissions do participate in photochemical reactions that produce ozone.

However, ozone modeling analyses performed by the state of New Mexico as part of the Early Action Compact (EAC) and ozone monitoring data in the area suggest that ozone formation is VOC limited and consequently NOx emission reductions may cause increases in ozone concentrations. Both SO2 and NO2 ambient concentrations are in compliance with federal and state air quality standards.

As a first order approximation, 1 ton per year of SO2 emissions will result in the same amount of potential visibility impairment as 1 ton per year of NOx. In reality, because of the more complex and competitive reactions involving both SO4 and NO3, SO2 emissions may result in more visibility impairment than NOx emissions.

From an economic basis, conversion of natural gas-fired engines to electric compression is only practical for large engines and only in areas where electricity is already available within close proximity. This is because most locations do not currently have electrical power and it would not be cost effective to install power for small engines.[3]

In Colorado, most large engines (greater than 500 hp) are lean burn or have NSCR installed to reduce emissions (average emission factor for this size engine is 1.4 g/hp-hr). In addition, any new engines in this size category must achieve an emission limit of 1 g/hp-hr.[4] These engines are typically located at remote sites where power is not available.

In New Mexico, for large engines (greater than 500 hp) the average emission factor is 3.0 g/hp-hr. There are a total of 354 engines in this size category.[5] Of that total, 221 engines have NOx emission less than or equal to 1.5 g/hp-hr (62 percent), 108 engines have NOx emissions in the range of 1.6 to 5 g/hp-hr (31 percent) and 25 engines have NOx emissions greater than 5 g/hp-hr (7 percent). Under a recent BLM EIS Record of Decision (ROD), new engines must achieve 2 g/hp-hr.

Method

The energy consumption of a typical lean burn engine was calculated, converted into pounds per mega watt-hour and was compared to SO2 and NOx emissions from existing coal-fired power plants. This was done assuming an emission factor between 1 g/hp-hr and 5 g/hp-hr. It was then assumed that the computed emissions per mega watt of power represented emissions for 1-hour and were converted into tons per year by multiplying by 8760 hours per year and dividing by 2000 pounds per ton.

As indicated in Table 4, a shift from natural gas to electric (coal) for an engine of 1 MWhr capacity (approximately 1,342) hp with an emission factor of 1 g/hp-hr would result in an **increase** of 14 tons per year of SO2 + NOx. With engine emissions of approximately 2.0 g/hp-hr there is no net change in overall emissions by shifting from natural gas to electric. For all cases, the shift from natural gas to electricity results in higher greenhouse gas emissions.

Conclusions

NOx emissions from large engines in Colorado and the remaining engines in New Mexico are currently controlled at sufficient levels so that shifting from natural gas to electric compression may only result in a small reduction in emissions and in many cases would result in an increase in SO2 and NOx emissions.

For all categories of engines, greenhouse emissions would increase by shifting compressors from natural gas to electric.

Table 4: Change in SO2, NOx and Greenhouse Gas Emissions by Shifting from Natural Gas Compression to Electricity

Four Corners Grid Average Emissions lbs/MWh		tons/MWh/yr
SO2	2.65	11.6
NOx	3.64	15.9
NOx + SO2	6.29	27.6
CO2	1,989	8711.8

Table 4A: Example Engine Changes

Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)		Other Emission Rates (gr/hp-hr)				
SO2	**0**	**0**	**0**	**0**	**0**	**0**
Hp/kw-hr	**1.342**	**1.342**	**1.342**	**1.342**	**1.342**	**1.342**
Hp/mw-hr	**1,342**	**1,342**	**1,342**	**1,342**	**1,342**	**1,342**
Cubic feet gas/mw-hr	**9,815**	**9,815**	**9,815**	**9,815**	**9,815**	**9,815**
NOx Emission Rate gr/hp-hr	**1**	**2**	**3**	**4**	**5**	**16**
SO2 lbs/mw-hr	**0**	**0**	**0**	**0**	**0**	**0**
NOx lbs/mw-hr	**3.0**	**5.9**	**8.9**	**11.8**	**14.8**	**47.3**
CO2 lbs/mw-hr	**1,138**	**1,138**	**1,138**	**1,138**	**1,138**	**1,138**
SO2 tons/MWh/yr	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NOx tons/MWh/yr	**13.0**	**25.9**	**38.9**	**51.8**	**64.8**	**207.4**
CO2 tons/MWh/yr	**4985**	**4985**	**4985**	**4985**	**4985**	**4985**
Delta SO2 tons/Mwh/yr	**11.6**	**11.6**	**11.6**	**11.6**	**11.6**	**11.6**
Delta NOx tons/Mwh/yr	**3.0**	**-10.0**	**-22.9**	**-35.9**	**-48.9**	**-191.4**
Delta NOx +SO2 tons/MWh/yr	**14.6**	**1.6**	**-11.3**	**-24.3**	**-37.3**	**-179.8**
Delta CO2 tons/Mwh/yr	**3727**	**3727**	**3727**	**3727**	**3727**	**3727**
Cat. 3608 Assumptions: **9815 Btu/kw-hr** **"Sweet" Natural Gas** **NOx - 1 gr/hp-hr** **1 cu ft gas = 1,000 btu**						

Endnotes:

1 Factors that need to be considered for use of a natural gas fired electrical generation system are: engines must be located in clusters that lend themselves to being interconnected by power lines; generator and line reliability need to be evaluated; the efficiency of electrical generators systems compared to natural gas fired compression must be evaluated; it needs to be determined if natural gas fired electrical

generators have substantially lower emissions than new natural gas fired compressor engines; cost and the benefits of this analysis need to be evaluated in terms of potential ambient air quality benefits, not simply emission reductions.

[2] EPA EGRID Program http://www.epa.gov/cleanenergy/egrid/index.htm

[3] The quantification of changes in emissions of this option does not address the cost of implementation or the reliability of the electrical grid. These issues must be considered if this option is deemed beneficial from an environmental perspective.

[4] Northern San Juan EIS Record of Decision (April 2007)

[5] NMED Part 70 permits, Minor source permits and Environ inventory.

Mitigation Option Analyses: Replace RICE Engines with Electric Motors for Selected Oil and Gas Operations (Alternative 2 – Power Source: On-Site Natural Gas-Fired Generators)

Description of Analysis of the Alternative Option

As an alternative to grid power, dedicated on-site, natural gas-fired, electrical generators can be used to supply power to electric motors suitable for selected replacement of "dirty" compression and other E&P RICE engines. This alternative to the Install Electric Compression (Grid Power Alternative) expands candidate engines for replacement beyond compressor engines since some existing compressor engines, particularly in the Northern San Juan Basin, are already well controlled. The electric motors are rated on an equivalent horsepower basis to RICE engines targeted for replacement. This analysis covers both the top 25 "dirtiest" and all essentially uncontrolled, primarily small, rich burn engines, with emissions greater than 4 g/hp-hr. Net NOx and CO emission reductions are reported in mass emission rates (tons/yr) and normalized mass emission rates (tons/yr/MW).

Assumption

The currently available gas electric generators run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural gas and field gas. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. The calculated net reduction in emissions from existing RICE engines to electric motors powered by on-site electric generators were done based on an equivalent power basis.

In order to implement this option an electrical infrastructure would need to be constructed between the locations of the gas fired generator and the electric compressors. In addition, a control system would have to be developed so that as the engine load (demand) varies the generator supply would be adjusted to meet the demand. In order to implement this option it may be necessary to connect the generator to the power grid so that excess electricity could be utilized. Several engine companies manufacture gas electric generators. We assumed use of a mid-size Caterpillar gas electric generator as the reference natural gas on-site generator for calculating the net emissions for this alternative (not to be construed as an endorsement). The Caterpillar G3612 gas electric generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx and 2.5 g/hp-hr CO. It is important to note that the emissions from such generators are not different than what can be achieved from a lean burn engine (available with a capacity in excess of 500 hp) and not appreciable different emissions from new NSPS engines.(2 g/hp-hr vs 0.75g/hp-hr).

The selection of RICE engines for electrification analysis did not consider important factors that would need to be weighed in determining the degree of implementation that might be feasible. This would include the locations and spatial distribution of engines (e.g., proximity of with each other), the number and cost of required on-site generators, maximum transmission line lengths and any ROW issues, number of electric motors and costs, and operational and environmental factors.

Available engine inventories, for producers in New Mexico and Colorado (e.g., bp) were combined in order to obtain a representative engine inventory for the San Juan Basin.

Method

The NOx and CO emission of the reference Caterpillar G3612 generator were given in g/hp-hr which was converted into lbs/MW-hr by multiplying the (1,342 hp/MW) and divided by (454 gm/lbs). Further, the NOx and CO emissions in tons/yr/MW units were obtained by multiplying 8760 hrs/yr and dividing by 2000 lbs/ton. The NOx and CO emission factors and calculated normalized emission rates for NG generator are given in Table 5.

Table 5: Gas Electric Generator Emissions

2,275 kW			
	(g/hp-hr)	(lbs/MWh)	(tons/yr/MW)
NOx	0.70	2.07	9.06
CO	2.50	7.39	32.37

The net emission reduction was first calculated for the replacement the 25 worst NOx emitters and compared with a greater subset of replaced engines (e.g., engines emitting more than 4 g/hp-hr engines). The selection of the 25 worst engines is based on potential tons/yr NOx emission of individual engines. The potential engine emission calculation assumes 100% load and 8760 hrs operation per year. Engine emission factors were obtained by combining the New Mexico and Colorado engine inventory database used the Alternative 1 analysis.

The following illustrates how the mass emission rates (ER) and normalized mass emission rates (NER) were calculated for each engine size group.

> EF (24.6 g/hp-hr) * Engine Size (1,350 hp) * (# of engines) * (8,760 hrs/yr) * (1/454g/lbs) * (1/2,000 lbs/ton) = 320.4 (tons/yr)
>
> EF (24.6 g/hp-hr) * (1,342 hp/MW) * (8,760 hrs/yr)*(1/454g/lbs)*(1/2,000 lbs/ton) = 318.5 (tons/yr/MW)

The 25 engines with the highest mass emission rates in the combined inventory were identified. The total power of these was obtained by adding the rated power of individual engines, which was used to calculate equivalent emission from gas generator needed to run the 25 electric motors replacing the replaced RICE engines. For the case of the 25 highest emitting engines, the average capacity is 684 hp, the maximum capacity is 2,400 hp and the lowest capacity is 325 hp. What is important about the capacities is that for the majority of these engines lean burn engines are available. Table 6 shows the normalized average emissions in tons/yr/MW as well as net potential mass emission reductions for both NOx and CO emission based on the 25 worst NOx emitters. The average emission factor for the top 25 engines is 23.9 g/hp-hr.

Table 6: Emission change if 25 worst NOx emitting engines retired

Total rated power = 17,108 hp = 12.8 MW		
	NOx	
	Avg. NER (tons/yr/MW)	Total ER (tons/yr)
Caterpillar G3612	+9.06	+115.51
Worst 25 Engines	-251.21	-3,106.40
Net Reduction	-242.14	-2,990.89

Table 7 shows the same calculations based on all the engines emitting more than 9 g/hp-hr.

Table 7: Emission change if all engines emitting > 4g/hp-hr NOx retired

<table>
<tr><td colspan="3">2925 engines with total rated power = 233,278 hp = 205.7 MW Emitting > 9 g/hp-hr NOx</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td colspan="2">NOx</td></tr>
<tr><td></td><td>avg/engine (tons/yr/MW)</td><td>Total (tons/yr)</td></tr>
<tr><td>Caterpillar G3612</td><td>9.06</td><td>1,863.75</td></tr>
<tr><td>All engines emitting more than 4.0g/hp-hr</td><td>211.36</td><td>40,562.21</td></tr>
<tr><td>Net Reduction</td><td>-202.30</td><td>-38,698.45</td></tr>
</table>

Conclusion

A net reduction of approximately 2,991 tons/yr of NOx can be achieved if the 25 engines with the highest NOx mass emission rate t operating in the San Juan Basin are replaced with nine 2 MW well controlled on-site natural gas electrical generators. Although most large RICE engines operating in the San Juan Basin are relatively small emitters individually and collectively, a significant number of small and medium range engines are not controlled well and collectively represent a relatively large E &P emission source group. The analysis in this alternative reveals a potentially significant emission reductions are possible for this group of engines. The calculation of emission reduction for replacing all the engines emitting more than 9.0 g/hp-hr NOx (over 2925 engines) with electric motors powered by several similar natural gas generators show that 38,698 tons/ per year of NOx reduction might be achieved by this option. This level of replacement would require approximately 90 on-site generators rated at 2 MW.

The potential emission reductions presented in this analysis assume optimal mitigation option implementation conditions which may not be nearly as optimistic if more detailed data were available and factored into the analysis. The selection of engines for electrification analysis did not consider important factors that would need to be weighed in determining the option feasibility and what degree of implementation would be possible. Factors such as the locations and spatial distribution of engines and operational and environmental issues would need to be considered. These and other factors would need to be carefully evaluated to better quantify the effectiveness of this alternative in terms of potential emission reductions achievable and certainly in quantifying implementation costs.

References

1. The emission and power information for the Caterpillar G3612 Gas Generator was obtained from Caterpillar's website. www.cat.com.

2. The engine inventory for NM and CO used to calculate emission reduction was provided by BP America, which includes contributions from: BP, New Mexico Environment Department, Colorado Dept. of Public Health & Environment and ENVIRON

Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines

Description of the Option

NO_X, CO, HC, and formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR) and is applicable only to stoichiometric engines. Engines must operate in a very narrow air/fuel ratio (AFR) operating range in order to maintain the catalyst efficiency. Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an AFR controller, emission reduction efficiencies will vary. Most AFR controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

An AFR controller will only maintain an operator determined set point. For this set point to be at the lowest possible emission setting, an exhaust gas analyzer must be utilized and frequently checked.

Some issues associated with current practice NSCR retrofits on existing small engines operating at reduced loads are:

- a problem maintaining sufficient flue gas inlet temperature for correct oxygen sensor operation and the resulting effectiveness of the catalysts
- On engines with carburetors, there is difficulty maintaining the AFR at a proper setting
- On older engines, the linkage and fuel control may not provide an accurate enough air/ fuel mixture
- If the AFR drifts low (i.e., richer), ammonia formation will increase in proportion to the NOx reduction but not necessarily in equal amounts.

The first issue can be mitigated by retarding the ignition timing when the engine operates at reduced loads. The retarded ignition timing reduces NOx emissions and also raises the flue inlet temperature which helps maintain the catalyst efficiency. Eliminating or mitigating the second, third, and fourth issues require a closed-loop feedback control with an exhaust oxygen sensor to continuously adjust the AFR. One way of doing this is to adjust the carburetor so it operates slightly lean and use the feedback control to adjust the amount of supplemental fuel supplied to a port downstream of the carburetor. Worn carburetors and linkages should be replaced as a maintenance issue.

Assumptions

Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new or replacement engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines. Most engines in the 4 Corners Region in excess of 500 hp are lean burn engines and that trend is expected to continue in the future. These engines meet low emission standards through lean burn combustion technology and NSCR catalyst cannot be installed on this type of source. Therefore, the implementation of NSCR technology would have little or no effect on emission levels for new or replacement engines in excess of 500 hp. New or replacement engines having capacities of less than 500 hp and 300 hp will be required to meet an emission limit of 2 g/hp-hr in Colorado and New Mexico, respectively. Because of the limited availability of lean burn engines in this size range, NSCR will have to be used to achieve the prescribed emission levels. Thus, it is very likely that new or replacement engines will use this technology and there will be no additional possible NOx emissions reductions. It is important to note that a properly designed and operated NSCR system can achieve emission levels less than 2 g/hp-hr. However, the question becomes one of maintaining emissions at lower levels on a continuous basis and the operator's need to have a safety factor for ensuring continuous compliance with source emission limits. Thus, on average, actual emissions will be less than the prescribed regulatory limits, however, there will be times when emissions will approach the regulatory limit.

In examining additional NOx mitigation (beyond current regulatory drivers), NSCR would be applicable to existing rich burn engines that have a capacity of less than 500 hp.

In order for NSCR technology to result in any reduction of NOx emissions in the 4 Corners Region, it would have to be implemented on existing engines less than 500 hp. Estimates of potential emission reductions were calculated for engines in the range of 300 to 500 hp, 100 to 300 hp and between 75 hp and100 hp. Currently, there is no single retrofit kit that can be installed on existing engines. Even if an air fuel ratio controller with an oxygen sensor were installed, it is uncertain if the carburetor linkage would allow an accurate and precise enough control required to maintain the proper air fuel mixture without repair or upgrade.

However, compliance data (unannounced tests) obtained from the SCAQMD for 215 retrofitted rich burn engines show that over 90% of these engines, with installed AFRC, were able to meet or do better than 2 g/hp-hr. Six engines were essentially uncontrolled due to lack of any installed AFRC. Over 77% of the tested engines did better than 1 g/hp-hr (SCAQMD, 2007).

Engine Size >300 hp and < 500 hp

The uncontrolled NOx emission factor for existing rich burn engines between 300 hp to 500 hp in Colorado and New Mexico ranges from 11.4 to 21 g/hp-hr. The average emissions from the 11 rich burn engines in this size group are 18.3 g/hp-hr. The mass emission rate of a combined 3,660 hp for these engines total nearly 650 tons NOx/yr. Many of the engines in the 300-500 hp range already had some emission controls on them (such as being lean burn).

In new applications, laboratory data shows that NSCR can exceed 90% NOx reduction and in some cases possibly 95%. Because mitigation is being considered on a fleet of older existing engines, it may not be possible to achieve a 90% plus level of performance reliably in the field. Field tests to address this and other issues are being planned by Kansas State and are expected to start soon. Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA., it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the identified 11 "dirty engines" could reduce the NOx emissions to 1.8 tg/hp-hr (an ~ 450 tons/yr reduction) at the low end and 5.5 g/hp-hr at the high end (an ~ 590 ton/y reduction).

Engine Size > 100 hp < 300 hp

The uncontrolled NOx emission factor for existing rich burn engines between 100 hp to 300 hp in Colorado and New Mexico ranges from 15 to 24 g/hp-hr. The average emissions from the 240 rich burn engines in this size group are 19.1 g/hp-hr. The mass emission rate of the combined 38,394 hp for these engines total over 7,000 tons NOx/yr. Some engines in this size range were excluded from this group because they were identified as lean burn

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 240 identified "dirty engines" could reduce the NOx emissions to 1.9 g/hp-hr (an ~ 6,500 tons/yr reduction) at the low end and 5.7 g/hp-hr at the high end (an ~ 5,000 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

Engine Size > 75 hp and < 100 hp
The uncontrolled NOx emission factor for existing rich burn engines between 75 hp to 100 hp in Colorado and New Mexico ranges from 9.4 to 22.4 g/hp-hr. The average emissions from the 901 rich burn engines in this size group are 19.7 g/hp-hr. The mass emission rate of the combined 84,307 hp for these engines total over 11,200 tons NOx/yr. The lowest emitters are a group of Ford engines that may have EGR, but the database does not specify whether they have EGR.

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 900 identified “dirty engines” could reduce the NOx emissions to 5.9 g/hp-hr (an ~ 11,200 tons/yr reduction) at the low end and 2.0 g/hp-hr at the high end (an ~ 14,400 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

There is considerable uncertainty in the NOx reduction in these engines, which tend to be older than the engines in other size ranges. Attention to worn linkages and carburetor parts as well as closed-loop AFR control is expected to be necessary if these engines are to achieve effective NOx reduction.

Additional long term testing of the use of NSCR on existing small engines must be performed prior to any large scale implementation of this option. Currently, testing is beginning that will address the field application of this technology for retrofit conditions on rich burn small engines..[1]

Method

A spreadsheet containing the combined engine inventories for Colorado and New Mexico was developed. For each of the three size ranges of interest, a new database was created in which engines outside the size range of interest were deleted. Each of the three newly created databases were further modified by deleting all engines that are identified by their model designation as “lean-burn” and by deleting all remaining engines whose NOx emissions are 5.0 g/hp-hr or less. The resulting three databases contain only rich-burn engines in the size ranges of interest. Overall NOx emissions were totaled for each of the three size ranges, and emissions reductions of 70% and 90% were applied. resulted in a reduction in NOx emissions of 723 tons per year (a 7 percent reduction of Colorado oil and gas emissions). The engines in the New Mexico inventory were treated similarly.

One important point is that the New Mexico inventory indicated that 1,024 engines were less than 40 hp, which is the proposed de minimus threshold in the NSPS. Under the proposed regulation, EPA concluded that control of this size engine is not appropriate or cost effective. In New Mexico this class of engines had emissions of 2,049 tons per year (i.e., each engine had emissions of approximately 2 tons per year).

Table 8 presents the projected changes in NOx emissions if NSCR were installed on existing engines in Colorado and New Mexico.

Table 8: Emission Reductions from implementing NSCR on Existing Rich Burn Engines in Colorado and New Mexico

Colorado and New Mexico, 70% Reduction - NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Average Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	70	5.5	3150	453
< 300 hp Eng > 100 hp	70	5.7	5948	4934
< 100 hp Eng > 75 hp	70	5.9	13317	11201
Total Reduction			**51783**	**16588**
Percent Reduction				**32**

Colorado and New Mexico, 90% Reduction – NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	90	1.8	3150	582
< 300 hp Eng > 100 hp	90	1.9	5948	6343
< 100 hp Eng > 75 hp	90	2.0	13317	14402
Total Reduction			**51783**	**21327**
Percent Reduction				**41**

Conclusions

Installing NSCR on existing engines less than 500 hp in Colorado and New Mexico would result in a reduction of approximately 16,588–21,327 tons per year of NOx over current projected emissions in 2018.

Additional field testing on the installation of retrofit NSCR on engines less than 500 hp is needed to document what level of emission control could be achieved on a continuous basis.

Detailed modeling is planned that will quantify the air quality benefit of such reductions either separately or in combination with other potential mitigation measures. For visibility, currently in the Mesa Verde and Wimenuche Class I Areas NOx emissions are a very small portion of the total extinction budget, however in recent years the trend has been flat or showed slight increases. Also, because of complex photochemical reactions involving VOC emissions and NOx emissions, changes in NOx emissions could result in localized increases or decreases in ozone. Regional effects of changes in ozone precursor emissions would need to be determined using a photochemical model.

Mitigation Option: Use of SCR for NOx Control on Lean Burn Engines

Description of the Option

Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with selective catalytic reduction (SCR). This technology uses excess oxygen in a selective catalytic reduction system. Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. A programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements is used to control the SCR system. Sampling cells are used to determine the amount of ammonia injected which depends on the amount of NO measured downstream of the catalyst bed.

In the proposed standards for Stationary Spark Ignition Internal Combustion Engines, EPA states the following with respect to the installation of SCR on natural gas fired engines: “For SI lean burn engines, EPA considered SCR. The technology is effective in reducing NOx emissions as well as other pollutant emissions, if an oxidation catalyst is included. However, the technology has not been widely applied to stationary SI engines and has mostly been used with diesel engines and larger applications thousands of HP in size. This technology requires a significant understanding of its operation and maintenance requirements and is not a simple process to manage. Installation can be complex and requires experienced operators. Costs of SCR are high, and have been rejected by States for this reason. EPA does not believe that SCR is a reasonable option for stationary SI lean burn engines. Consequently, this technology is not readily applicable to unattended oil and gas operation that do not have electricity.[1] However, the technology has been used successfully on lean-burn engines to meet Southern California's stringent limit of 0.15 g/hp-hr. The SCAQMD’s staff report supporting Rule 1110 identifies SCR as a RACT on lean burn engines capably of achieving over 80% NOx control. The staff report also notes that SCR is a relatively high cost control technology option for RICE engines. Reasons given include the “capital cost for the catalyst, the added cost and complexity of using ammonia, and the instrumentation and controls needed to carefully monitor NOx emissions and meter the proper amount of ammonia.” However they also note that the estimated costs have been declining over the past several years and are currently estimated to range from $50 to $125 per horsepower.

Assumptions

There is very little information in the literature regarding the incremental NOx emission reduction of SCR beyond lean burn technology for remote unattended oil and gas operations because there have been very limited installations of this technology for oil and gas compressor engines. Table 9 presents a summary of incremental SCR emission reductions and cost effective control estimates for SCR on a lean burn engine.[2]

Table 9: Incremental SCR Emission Reductions and Cost Effective Control Estimates for SCR

Incremental Cost-Effectiveness Estimates for ICE			**Control Techniques and Technologies**	
			Incremental	**Incremental NO_X**
Engine Type	**Control Comparison**	**Horsepower**	**NO_X Reduction**	**Cost-Effectiveness**
			(tons/year)	**($/ton of NO_X Removed)**
Lean Burn				
	From Low-Emission Combustion to SCR (96%)	300-500	**3.3**	8,800
		500-1000	**6.6**	10,300

There are several concerns regarding this information. First, it is not known if the emission reductions are based on actual performance tests or theoretical emission calculations. It is also not known what the reference basis is for the emission reduction of 6.6 tons per year of NOx. Review of CARB databases regarding NOx engine emissions does not provide any data regarding actual installations of SCR on lean burn engines for oil and gas operations. There is some very limited performance testing on SCR with lean burn engines that operate on pipeline natural gas (as opposed to field gas) for cogeneration facilities. Such emission data for cogeneration facilities is not applicable to oil and gas compressor engines. This is because cogeneration facilities tend to operate at a continuous load and have personnel present to operate the equipment. The CARB databases also provide testing of oil and gas SCR for high emitting 2 cycle engines (removal rates in the range of approximately 50 to 85 percent). These installations are not comparable to adding SCR to a well controlled engine.

Because of the limited application data for SCR on natural gas fired engines for oil and gas operations it is difficult to estimate the amount of potential emission reduction that could be achieved through the implementation of this technology. In addition, it is not clear how well this technology would perform in unattended remote applications. The limited data that does exist suggests that there may only be a small incremental reduction in NOx emissions beyond lean burn technology and this reduction would result at a very high incremental cost. This technology should be considered an emerging technology and merits additional testing for this unique application.

Because of non-linear chemistry involved in photochemical reactions of ozone and secondary aerosols that result in a reduction of visibility, NOx emission reductions estimated in this analysis may or may not result in equal improvement in ambient air quality levels. Also, excess ammonia slip within the discharge plume of an engine may accelerate the conversion of NOx emissions into particulate nitrate.

Table 10 presents CARB budgetary costs for the installation of SCR on lean burn engines.

Table 10: Cost-Effectiveness Estimates for ICE Control Techniques and Technologies

Selective Catalytic Reduction for Lean Burn				
Horse Power Range	**Capital Cost (S)**	**Installation Cost(S)**	**O&M Cost (S/year)**	**Annualized Cost (S/year)**
301-500	43,000	17,000	35,000	36,000
501-1000	116,000	33,000	78,000	78,000
1001-1500	132,000	53,000	117,000	148,000
Average gt 500 hp	**124,000**	**43,000**	**97,500**	**113,000**

It should be noted that in a white paper prepared by Thomas P. Mark regarding control of Engines in Colorado that he estimates the annual operating cost of SCR on an engine having a capacity of 1000 hp is approximately $140,000 per year and is consistent with the CARB estimate.[3]

Conclusions

The installation of SCR beyond lean burn technology is not a proven or cost effective technology at the present time. With additional development and testing for oil and gas operations, it may become an effective control technology for tertiary control of lean burn engines.

Endnotes

[1] Federal Register Monday, June 12, 2006 40 CFR Parts 69, 63, et al. Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating internal Combustion Engines; Proposed Rule

[2] California Environmental Protection Agency Air Resources Board, 2001, "Determination of Reasonably Available Control Technology.

[3] Thomas P. Mark, October 31, 2003, Control of Compressor Engine Emissions Related Costs and Considerations.

Mitigation Option: NSPS Regulations

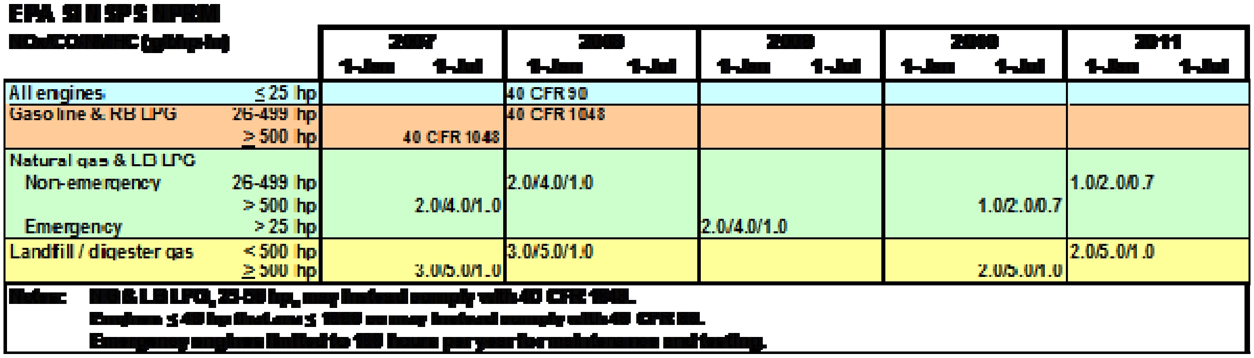
Description of Option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

New Source performance Standards (NSPS)



EPA SI NSPS NPRM

NOx/CO/NMHC (g/bhp-hr)		2007		2008		2009		2010		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	≥ 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	> 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

Notes: NG & LB LPG, 25-50 hp, may instead comply with 40 CFR 1048.
Engines ≤ 40 hp that are ≤ 1000 cc may instead comply with 40 CFR 90.
Emergency engines limited to 100 hours per year for maintenance and testing.

Since the proposed NSPS will become an EPA regulation, it will become the base case for emissions for new modified and reconstructed engines. As such, the benefits of this regulation are already incorporated into the Cumulative Effects emission inventories.

Mitigation Option: Optimization/Centralization

Description of Option

Under this option, natural gas fired internal combustion engines that are used to power various oil and gas related operations would be installed with appropriate sized engines (horsepower) for the activity being conducted. The advantage of this approach would be reducing the cumulative amount of horsepower deployed and might result in reducing emissions. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.

Assumptions

1) Current lease agreements for production cannot be easily changed.
2) Engine emission factors do not change with load.
3) Emission factors on small new, modified and reconstructed engines are consistent with large engines (proposed NSPS will require this).

Method

Short term emissions from compressor engines are based on the amount of fuel used which is a function of capacity (hp) and load. In determining annual emissions, the hours of operation are important. Assuming that emission factors do not change with load, as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions

Conclusions

Implementation of this option will not result in any quantifiable reduction in emissions.

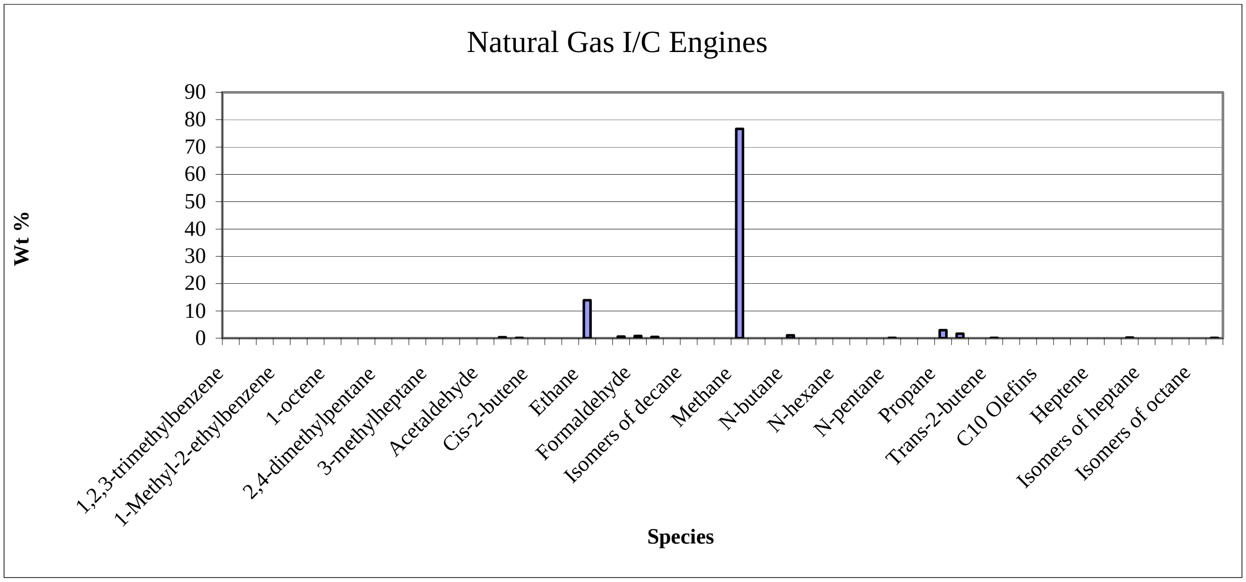
Mitigation Option: Use of Oxidation Catalyst for Formaldehyde and VOC Control on Lean Burn Engines

Description of Option
Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with oxidation catalyst to convert formaldehyde and VOC emissions to CO2. This technology requires the use of an air fuel ratio controller (AFR) in conjunction with the catalyst.

Assumptions
In developing emission inventories for the Four Corners Region, it was assumed that formaldehyde emissions from natural gas fired engines were 0.22 g/hp-hr for all types of engines. There is a large uncertainty in emission factors for formaldehyde which is why a conservative value of 0.22 g/hp-hr was assumed for all engines. In reality, lean burn engines have higher formaldehyde emissions than rich burn engines and therefore it is more appropriate to consider oxidation catalyst technology only for lean burn engines.

The emission inventory for VOC engines used manufacturers' emission factors. There is a large uncertainty if those emission factors represent total hydrocarbons (THC) or VOCs and also they do not include formaldehyde. THC includes methane (C1) and ethane (C2) which EPA does not regulate because they have low photochemical reactivity. The following figure presents the speciation of organics from natural gas fired engines from the EPA Speciate data base and indicates that the majority of the hydrocarbon emissions are methane and ethane. Thus, the projected reductions in hydrocarbon emissions may not affect ozone formation.

Composition of Hydrocarbon Emissions from Natural Gas Fired Engines

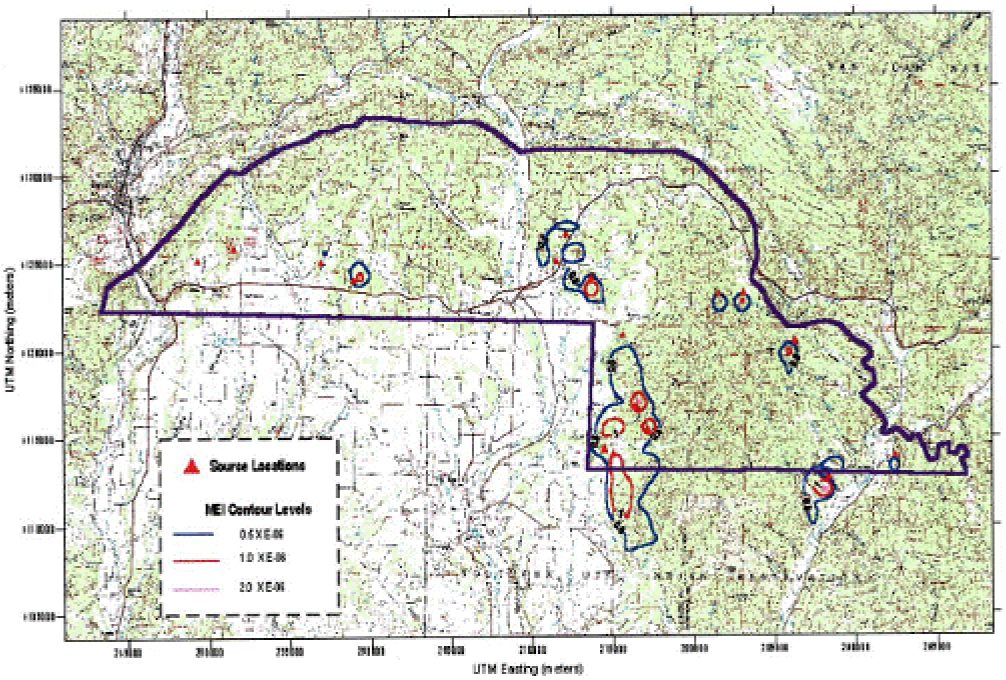


It was assumed that this technology could obtain a 90 percent reduction in hydrocarbons and 80 percent reduction in formaldehyde.

Previous modeling analyses of formaldehyde HAP impacts indicate that maximum impacts for the most likely exposed individual (MLE) are approximately 4x10-6 and have a very localized impact.[1,2] A plot indicating the formaldehyde impacts is presented in the following figure.[3]

Formaldehyde Isopleths from Northern San Juan EIS

Figure 7-5. HAP Incremental Risk Analysis for Formaldehyde MEI (Maximum Development)



Method

Table 11 presents the projected changes in formaldehyde and hydrocarbon emissions if oxidation catalyst were installed on new engines in Colorado and New Mexico.

Table 11: Estimated Changes in VOC and Formaldehyde Emissions with the Installation of Oxidation Catalyst

	VOC Reduction (t/yr)	Unmitigated VOC (t/yr)	Percent VOC Reduction	Formaldehyde Reduction (t/yr)	Unmitigated Formaldehyde (t/yr)	Percent Formaldehyde Reduction
Colorado	204	3115	7	42	471	9
New Mexico	1415	[Frame2] 42,117	3.4	382	365	40

In Colorado, the installation of oxidation catalyst on new engines greater than 300 hp$_4$ would result in formaldehyde emission reductions of 42 tons per year (a 9 percent reduction in emissions) in 2018. This option would also result in a reduction of 204 tons per year of VOC emissions (a 7 percent reduction in emissions) in 2018. In New Mexico, the installation of oxidation catalyst on new engines greater than 300 hp would result in formaldehyde emission reductions of 385 tons per year (a 40 percent reduction) in 2018. This option would result in a reduction of 1,415 tons per year of hydrocarbon emissions (primarily methane and ethane) and would correspond to a 3.4 percent reduction in total emissions in 2018.

Conclusions

Installing oxidation catalyst on new engines greater than 300 hp in Colorado would result in a reduction of approximately 42 tons per year of formaldehyde over current projected emissions in 2018. and 204 tons per year of VOCs (primarily methane and ethane).

Installing oxidation catalyst on new engines greater than 300 hp in New Mexico would result in a reduction of approximately 382 tons per year of formaldehyde and 1,415 tons per year of hydrocarbons (primarily methane and ethane) for new engines in 2018.

There is a large uncertainty in the VOC estimates because the emitted compounds may be methane and ethane which are not regulated VOCs.
Detailed modeling is necessary to determine the air quality benefit of such reductions with respect to VOCs.

Previous HAP modeling indicates that there are minimal and very localized HAP impacts from natural gas fired engines.

Endnotes

[1] Dames and Moore 1999, “Southern Ute Environmental Impact Statement.

[2] RTP Environmental, 2004, “Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement.”

[3] RTP Environmental, 2004, “Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement.”

[4] The lower size cutoff for current lean burn technology.

Mitigation Option: SNCR for Lean Burn Engines

Description of the mitigation option

SNCR stands for Selective Non-Catalytic Reduction. It is similar to Selective Catalytic Reduction (SCR), except that it lacks a catalyst. Like SCR, SNCR can be applied to lean-burn or diesel engines and urea or ammonia is injected into the exhaust manifold. Because it lacks a catalyst, SNCR has a lower conversion efficiency than SCR has.

Do not confuse SNCR with NSCR (Non-Selective Catalytic Reduction), which is applicable to rich-burn engines and uses a catalyst but does not use ammonia or urea as a reductant.

SNCR is used primarily for NOx reduction in boilers. It use in engines has been supplanted by SCR because it has a higher NOx reduction efficiency than SNCR.
SNCR at best can convert only about 60% of the NOx in the exhaust stream compared to about 90% for SCR. Like SCR, SNCR is subject to ammonia slippage.

Because of the low NOx removal rate, the uncertainty in application to natural gas fired engines and because more effective proven technologies exist, this option was not evaluated further.

Mitigation Option: Next Generation Stationary RICE Control Technologies

In evaluating the next generation RICE control technology, it is important to note that current engine technology has resulted in substantial NOx reductions in natural gas fired engines compared to engines that were installed 10 years ago. New large lean burn engines are achieving over 90 percent control reliably and cost effectively. In order for the next generation of controls to be implemented in the field they must achieve the same standards.

In the near term lean-burn technology could be applied to engines smaller than 500 hp. This is a decision to be made by the engine manufacturers with the driving force being emissions regulations. Alternatively, the engine manufacturers or after market control technology companies could partner with researchers at universities and/or national laboratories to test, verify and develop reliable rich burn engine non-selective catalytic reduction (NSCR) system retrofit kits (e.g., air/fuel ratio controllers, lambda sensors, TWC, ion sensors). A next generation NSCR system could include nitrogen injection to achieve higher levels of NOx control (> 95%). The NSCR for rich burn engines may be a very attractive option for the oil and gas industry and for control technology vendors since the technology is well developed and certified for automobile applications.

With that preface this analysis investigates the status of three new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, and lean-burn NOx catalyst (including NOx traps).

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

I. Laser Ignition

Description of the Mitigation Option

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Air at high pressure is a good electrical insulator that requires high voltage to overcome. This limits the turbocharging pressure and compression ratio because the insulation on spark-plug wires breaks down at high voltage. Laser ignition is not subject to the same limitation, so a lean-burn engine with laser ignition can have a higher turbocharging pressure and a higher compression ratio than one with spark plugs.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Laser ignition may be able to reduce NOx emissions by as much as 70% compared to spark-ignited engines.[1] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure are responsible for the decrease of NOx emissions because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be significantly reduced. Whether laser ignition combined with lean-burn engine technology can meet the Southern California NOx limit of 0.15 g/hp-hr will be the subject of further research.

One of the advantages of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Laser ignition would compete with selective catalytic reduction (SCR) applied to lean-burn engines. Although costs are unknown at this time, laser ignition is likely to be the lower cost alternative.

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

Assumptions

In the analysis, it is assumed that the limitations of laser ignition described above can be overcome through research and development. It is further assumed that NOx emissions can be reduced by 70% compared to spark-ignition lean-burn engines. Until more research is done, the 70% reduction is most likely an upper limit. This reduction is due to the ability to operate at higher turbocharging pressure, hence leaner air/fuel ratios and lower combustion temperature than is currently possible with spark-ignition engines. Since lean-burn engines are primarily those over 500 hp, the technology is assumed to apply only to engines larger than 500 hp. The technology is assumed to be retrofitable to any engine that uses 18-mm spark plugs, so it is applied to all engines, new and existing, in the Colorado and New Mexico databases.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 30% to 60% range, which may or may not be achievable when this technology is implemented in the field.

II. Air-Separation Membranes

Description of the Mitigation Option

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions in diesel engines at the expense of increased NOx emissions. However, Poola[2] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small and have not been tested with natural gas-fueled engines, so it will not be considered further.

Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases. It can be applies to either diesel or rich-burn natural-gas engines. Unlike exhaust-gas recirculation (EGR), nitrogen-enriched air contains only the components of pure air. Manufacturers of both diesel and natural-gas engines are concerned that components of exhaust gas could shorten the life of the engines with EGR. In the case of diesel engines, it is clear that exhaust particulate matter could cause wear between the piston rings and cylinder liners. Even in the case of rich-burn engines, the exhaust gas contains condensed liquids that may cause wear. As recently as August, 2004, the Engine Manufacturers Association does not consider EGA to be a viable option for rich-burn engines.[3] Thus, nitrogen enriched air is seen as an alternative to EGR because it contains no components that are not found in air. Published data from tests in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air.[4] When combined with non-selective catalytic reduction (NSCR), the overall NOx reduction can reliably exceed 90%.

The cost of nitrogen-enriched air systems are expected to be higher than that of EGR. However, nitrogen-enriched air does not have components that can cause increased engine wear as EGR does.

Assumptions

Only nitrogen-enriched air is considered in this analysis. The technology is assumed to be retrofittable to all rich-burn engines, new and existing. While nitrogen-enriched air can be combined with non-selective catalytic reduction (NSCR), only the effects of nitrogen-enriched air are considered here. The effect is assumed to be the same as that of EGR; it can produce a 70% reduction in NOx emissions. This is most likely an upper limit.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 50% to 90% range, which may or may not be achievable when this technology is implemented in the field. The upper end assumes integration as a component of a reasonably well-designed (use of current state of the art air fuel ratio controllers / sensor technologies) NSCR system.

III. Lean-Burn NOx Catalyst, Including NOx Trap

Description of the Mitigation Option

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR. They do not have the ammonia slip problem associated with SCR, but they typically use some of the fuel as a reductant.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical.[5]

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published. [6,7] Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel.[8,9,10]

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. With natural gas as the fuel, a fuel reformer is necessary to break up the extremely stable methane molecule for use as a reductant When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published.[11] A sophisticated engine control is required to make this system work.

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm.][11] $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks.[12] Estimates are $10-$20/BHP for stationary engines [icengine.pdf]. [14]

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Assumptions

Only NOx-trap catalysts, which can remove up to 90% of the NOx in the exhaust stream are considered for this analysis. The technology is applicable to lean-burn engines, which are considered to be those having more than 500 hp in the Colorado and New Mexico databases. The technology is assumed to be retrofitable, so it is applied to all new and existing engines greater than 500 hp.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 40% to 70% range, which may or may not be achievable when this technology is implemented in the field.

Summary

Three technologies are reported: laser ignition, air-separation membranes, and lean-burn NOx catalyst.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes are not applicable to lean-burn natural-gas engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A large part of the cost of SCR is the ammonia or urea reductant necessary to make it work. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

Endnotes

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10 Magdi K. Khair, partha P. Paul, and Michal G. Grothaus, “Synergistic Approach to Reduce Nitrogen Oxides and Particulate Emissions from Diesel Engines, 08-9051,” Southwest Research Institue, 1999.

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12 “Summary of Potential Retrofit Technologies, Technical Summary,” U.S. Environmental Protection Agency, March, 2006.

13 “WRAP Off-raod Diesel Retrofit Guidance Document, Volume 2, Section 4,” November, 2005.

14 Manufacturers of Emissions Controls Association, op cit.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely, assume 25%.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Automation would not quite "zero out" vehicle-related emissions for those wells that are automated because of non-routine maintenance, perhaps it would be reduced by 80%.

Vehicle miles traveled is proportional to dust generated.

Method

Applying the percent reduction, 80% reduced by 50% to account for extent of oil and gas traffic and further reduced by 75% to account for effectiveness. So, the over all reduction would be 10%.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 of PM2.5.

For tailpipe emissions, the total NOx emissions in the region are 916 tpy, which means the reduction because of automation would be 92 tpy.

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely because it is voluntary, assume 20% participation which is a bit higher than is usually assumed for regulatory programs.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water and of which 20% will likely undertake the program. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 39 tpy of PM10 and 4 tpy of PM2.5.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

Miles traveled is proportional to dust generated.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 tpy of PM2.5.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

Assumptions

About 25% of traffic on dirt roads in the Four Corners region is on oil field lease roads.

Once applied, the improved surface would be maintained regularly by grading and reapplying gravel or rock.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have had an EPA-recommended factor that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

The level of emissions reductions achieved by the application of gravel to roadways can vary from place to place.

Considering uncertainties in road dust emissions estimates, the more conservative end of a range will be used.

Method

The total annual road dust emissions of PM10 in the Four Corners region are 1959 tpy (tons per year), and 196 tpy of PM2.5 based on the inventory information from the WRAP.

Based on a comprehensive EPA study (Raile, 1996) conducted in the Kansas City, Missouri area, emissions of PM10 were reduced by 42% to 52% by the application of gravel.

Conclusions

Therefore, emissions of PM10 on lease roads would be reduced by about 206 tpy, and by about 21 tpy of PM2.5. This is based on the following:

reduction of particulate from lease roads =
total road dust emissions times 25% times 42%.

References

Raile, M.M. 1996. Characterization of Mud/Dirt Carryout onto Paved Roads from Construction and Demolition Activities. U.S. EPA. EPA/600/SR-95/171.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

Assumptions

The average posted speed is 30 mph.

About half of the vehicles on dirt road exceed the posted limit by more than 5 mph. The average for these drivers is 40 mph or 10 mph over.

Therefore, the reduction in speed for those exceeding posted limits would be about 10 mph if enforcement was undertaken and was 100% effective. Such enforcement is not 100% effective.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor that estimates the transportable fraction, i.e. how much would move beyond the immediate vicinity.

The effectiveness of enforcement initiatives is dependent on resources allocated.

Method

The equation for estimating road dust PM10 emissions from EPA’s AP-42 is:

((1.8*(silt content/12)^.1) * (veh. Speed/30)^.5) - .00036) /
(surface moisture/.5)^.2

Therefore, adjusting the vehicle speed would change the multiplier in the numerator from 1.15 (i.e. (40/30)^.5) to 1.0 (i.e. (30/30)^.5).

So, assuming even 50% effectiveness in mitigating speeding, and generally the assumption is lower, the reduction from enforcing a 30 mph speed limit on dirt roads in the entire Four Corners region would be about 7.5%.

Conclusions

Remembering that half of the traffic on dirt roads are exceeding the speed limit by more than the threshold 5%, applied to the total road dust emissions of PM10 of 1959 tpy, the reduction would be approximately 73 tpy. The reduction in PM2.5 from a total of 196 tpy would be 7 tpy.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be Used Over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Region

Assumptions

Generally, much post-construction ambient monitoring for permitted facilities by the source is conducted on-site. Air quality permits generally contain conditions to require continuous emissions monitoring from the stacks for criteria pollutants. New federal mercury rules will require continuous emissions monitoring for mercury for Desert Rock Energy Facility beginning in 2010.

Given the tall stack heights of the proposed facility, the greatest air pollution impacts from emissions from the facility will be quite some distance from the facility.

Review of Proposed Approach

Continuous PM2.5 monitoring of primary fine particulate by the facility on-site would not likely provide useful information where the effect of emissions would be well downwind, plus direct fine particulate emissions by more modern power plants are usually not substantial. However, monitoring fine particulates and its chemical components (including ammonia) at off-site locations where models indicate significant impacts from the facility would be useful. Also, since much fine particulate is formed in the atmosphere rather than emitted directly, measurements of sulfur dioxide and oxides of nitrogen offsite would also be useful.

Stack mercury measurements might be useful from a research perspective in performing source apportionment work in the Four Corners region.

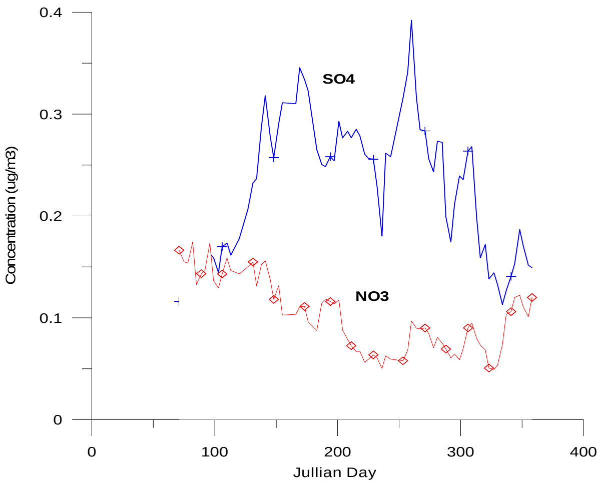
As is discussed above, on-site ambient monitoring of volatile organic compounds (VOC) may not be an effective means of understanding the ambient impact of these emissions, but off-site monitoring of ozone precursors like VOC and nitrogen oxides at predicted maximum impact locations would be useful.

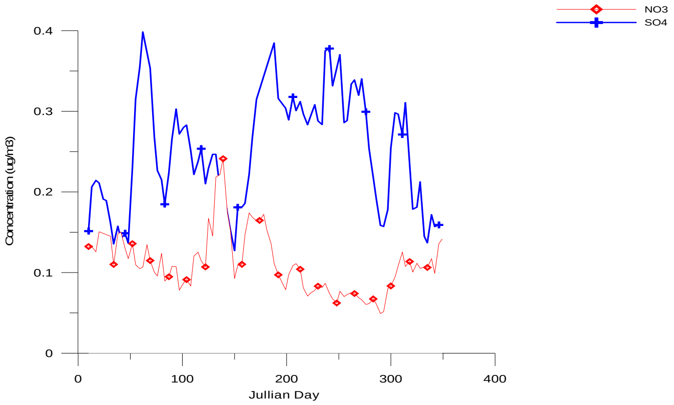
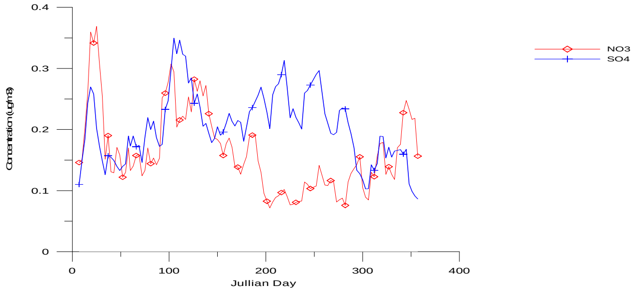
CUMULATIVE EFFECTS: PUBLIC COMMENTS

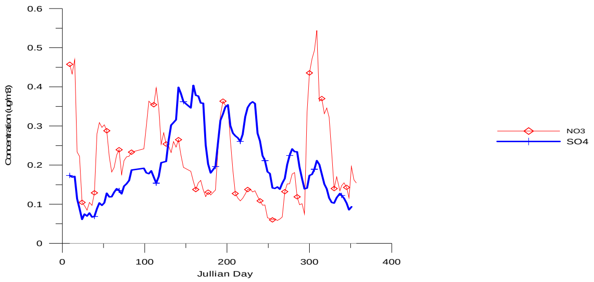
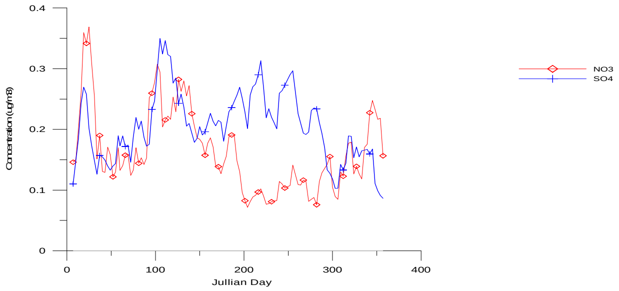
Cumulative Effects Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment
The Task Force report presents data on the potential emission reductions for the Four Corners Power Plant and the San Juan Power Plant. The Cumulative Effects Work Group needs to evaluate potential power plant mitigation options that are presented in the report and develop a quantitative summary of all potential mitigations options which have technical merit. It is useful to place the emission reductions suggested for power plants in perspective to those developed for oil and gas sources. As stated in the Draft Report, for the Four Corners Power Plant the installation of presumptive BART could result in SO2 emission reductions from a minimum of 12,455 tons per year to a maximum of 19,927 tons per year. Similarly, NOx emission reductions could range from 13,651 tons per year to 57,118 tons per year. Since SO2 and NOx emissions are considered as having similar visibility impairment potential, the magnitude of the total emission reductions possibly affecting visibility could range from 26,106 to 77,045 tons per year. For the San Juan Power Plant using data presented in the Task Force Report, estimated SO2 emission reductions could be approximately 9,000 tons per year and NOx reductions could be approximately 11,000 tons per year. For this plant the combination of SO2 and NOx possible reductions of 20,000 tons per year might be achieved. The information contained in the Draft Report regarding possible emission reductions for this source is not as complete as for the Four	General Comment

Comment	Mitigation Option
Corners Plant and additional data should be developed and presented. If the suggested emission reduction strategies were implemented at both plants, total SO2 and NOx emission reductions of visibility impairment pollutants could range from 46,106 tons per year to 97,046 tons per year. In addition, review of the emission data in the Draft Report indicates that at the Four Corners Power Plant NOx emissions are greater than SO2 emissions (Figure 2 FCPP Emission Trends). However, in 2003 SO2 emissions were further reduced so that the ratio of NOx to SO2 emissions increased. At the San Juan Power Plant prior to 1990, SO2 emissions were greater than NOx emissions while in 1999 SO2 and NOx emissions were equal (Figure 1 San Juan SO2 and NOx). After that time, SO2 emissions were less than NOx emissions. The trends in emissions at these facilities may be important in understanding the trends in the IMPROVE monitoring data. Engineering and economic feasibility studies need to evaluate the ability of the facilities to continuously achieve emission reductions in a cost effective manner. The potential emission reduction that could be realized with the installation of additional controls on power plants need to compared with the emission reductions reported by the Draft Task Force Report for oil and gas sources. The installation of NSCR on existing small engines in Colorado and New Mexico could result in emission reductions of approximately 10,244 tons per year. These emission reductions are only a small fraction of the reductions possible from power plants (minimum ratio of power plant reduction to oil and gas reductions 4.5 – maximum ratio of power plant reduction to oil and gas reductions 9.5).	
The Draft Task Force Report presents recommendations for mitigating emissions from drilling rig diesel engines. At the present time there is insufficient information regarding the level of emissions from these sources in the region. The Cumulative Effects Group should develop emission data regarding the magnitude of emissions in both Colorado and New Mexico and then develop estimates of potential emission reductions that could be achieved. The emission calculations should be based on site specific information that represents the length of time to drill a new well, engine loads and engine capacity. One important fact that needs to be considered is that the drilling rig engines are typically replaced at a frequency of every 5 years (replaced not rebuilt). This rate of turnover is very important because the engines are replaced with the required current control technology. This should be the baseline against which alternative mitigation options should be considered. It is recommended that the Cumulative Effects Group continue to analyze and evaluate emission reduction options for this source group.	General Comment
The following plots present selected years of rolling 5 data point averages of the SO4 and NO3 concentrations compared to Julian day for the IMPROVE data from Mesa Verde. Using a rolling 5 data point average provides some smoothing of the data but allows correlations between SO4 and NO3 to be observed. The plots for 1988 and 1990 indicate a large fraction of coincident peaks of SO4 and NO3. This is an important finding because it suggests that these events may result from coal fired sources because natural gas fired sources or mobile sources do not emit significant SO2. In addition, NO3 concentrations are smaller than SO4 concentrations. The data from 2002, 2003 and 2004 indicate that a change has occurred in the relationship of SO4 and NO3 measurements and that there is a very strong correlation of SO4 and NO3	General Comment

Comment	Mitigation Option
events, again suggesting a coal fired source. However, in 2002, 2003 and 2004 NO3 concentrations are equal to or greater than SO4 concentrations. As mentioned in the power plant emission section, SO2 reductions began in 1999 and after that time NOx emissions were greater than SO2 emissions. This trend in changes in emissions is very consistent with the monitoring data and again suggests visibility impacts are likely from coal fired sources. This is a preliminary hypothesis that needs more evaluation and may explain why NO3 levels have been increasing at Mesa Verde. If this finding is confirmed, it has important ramifications regarding improvement in air quality. This is the type of focused analyses that needs to be conducted before mitigation options are selected and implemented.  **1988 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	

Comment	Mitigation Option
 1990 SO4 and NO3 concentrations 5 day running average  **2002 SO4 and NO3 Concentrations 5 Day Running Average Mesa Verde**	

Comment	Mitigation Option
 **2003 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**  **2004 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	
last paragraph before Suggestions for Future Work...should the reference be to Table 2 rather than Table 1?	Overview of Work Performed

Comment	Mitigation Option
Table 1 - Selective Catalytic Reduction (SCR) on Drilling Rig Engines: It is stated "that some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed." This paragraph references the cost analysis WY did for SCR on diesel rig engines, but does not provide or reference any information on what conditions and assumptions WY used in conducting this analysis. If possible the CE workgroup should obtain and review the WY analysis on SCR, in addition to other diesel control options WY analyzed. Table 1 - Follow EPA New Source Performance Standards (NSPS) for RICE: EPA suggests revising the Summary of Result first sentence "This proposed emission standard will become the baseline for new, **modified, and reconstructed** engines. Table 1 - Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE. It is unclear in the Summary of Result what EPA performance standard is being referenced, and how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE have been considered by the CE workgroup. The NSPS for spark ignition engines will apply to **new, modified, and reconstructed** units starting in January 2008. The 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE notes that BLM/USFS, at the request of CO and NM, is currently requiring NSPS comparable emission limits on as a Condition of Approval for their Applications for Permits to Drill. The States' request was that BLM/USFS immediately establish in every Application for Permit to Drill (APD) a nitrogen oxide (NOx) limit of 2.0 grams per horsepower hour for all **new and replacement** engines less than 300 hp (excluding engines with horsepower less than 40). In addition, New Mexico and Colorado have requested that for all new and replacement engines greater than 300 hp, the BLM and the USFS establish in every APD a NOx limit of 1.0 gram per horsepower hour. EPA Region 8 formally supports both these requests from Colorado and New Mexico. It should also be noted that the Mitigation Option: Interim Emissions Recommendations for Stationary RICE section in the Draft Mitigation Options Report states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval for their Applications for Permits to Drill. These limits currently apply only to **new and relocated** engines ... (compressors assigned to the well APD)..." In developing assumptions for potential NOx reductions from this requirement in APDs, how did the CE workgroup determine, or assume, what percentage of the existing engines (compressors) in the 4 Corners area would be required to meet this requirement?	Overview of Work Performed

Comment	Mitigation Option
1. Given electric compression would shift emissions generated from NG compressor engines through use of electric engines to emissions from power generation (i.e., "the grid"), this option is clearly "cross-cutting." We recommend that the coordination with the Power Plant WG in the analysis of this option. 2. We were unable to reproduce the emission reduction numbers from the data provided in the analysis (tons/yr deltas provided in Table 4). Based on the data provided we calculate a total of 631 tons/yr reductions in NOx and SO2 based the 25 worst engines and the average power plant emissions in Table 3. 3. In course of installing electric compression to replace the natural gas fired compression engines, the analysis correctly assumes that the emission of pollutants will shift from the replaced compressor engines to increased electric load demand from the grid. In course of review of the Natural Resources Defense Council (NRDC) "Emission Data for the 100 Largest Power Producers", it appears that baseline average emission factors used for emission difference calculation are the national average emission factors for the identified owner utility companies (average of all plants, regardless of location or on which power grid). The electric power for electric compression will come from the Western Grid which draws power from generating stations in the western United States. Among the three electric power producers, Xcel is the largest producer with 81,283,493 MWhs capacity compare to 21,230,675 MWhs for both PNM and Tri-state. The baseline average emission factors based on national average emission factors of these three electric power producers have potential to distort the emission difference calculation because Xcel's power generation facilities in Minnesota, South Dakota, Texas, and Wisconsin are not supplying electricity to the Western Grid. A brief description of grid system is provided later in this document. A better measure of the effectiveness of this option would be the use of average NOx and SO2 emissions from Four Corners Generating Station and San Juan Generating Station. In case example case provided in the analysis, replacing 25 worst engines with total 2,701 hp in NM side with electric compression, will result in net NOx + SO2 reduction of 610 tons/year. A net NOx +SO2 reduction of approximately 20,000 tons/year can be achieved by replacing all rich burn engines (approximately 1,500 in NM inventory) emitting greater than 5 g/hp-hr. Although it may not be practical or economically feasible to replace all rich burn compressor engines with electric motors, further analysis of the locations/ configurations of existing compressor stations may reveal that conversion to electric is practical and makes sense. Factors like proximity to the electric grid, ROW, number of engines, are factors that would need to be evaluated. 4. The electricity for the electric compression in the San Juan area will be drawn from Western Interconnect or Grid. We recommend that a good approximation for baseline emission factors will be the averages of emission factors for the power plants supplying electricity to the Western Grid. The following steps can be taken to obtain the baseline average emission factors for the emission difference calculation: a. The average emission factors for fossil fuel powered power plants supplying electric power to the Western Grid can be calculated using the emission data	Install Electric Compression

Comment	Mitigation Option
from the EPA's CAMD inventory. The EPA's Clean Air Market Data (CAMD) (http://camddataandmaps.epa.gov/gdm/index.cfm) provides NOx, SO2, and CO2 emission as well as heat input for the Title IV power generating units. b. The net power generation by state by type of producer by energy source is available at the Energy Information Administration (EIA) website (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html). c. A fraction between calculated average baseline emission factors for the Western Grid based on EPA data and the total power generation for the Western Grid obtained from EIA's website will used to obtain the average baseline emission factors for emission difference calculations. 5. The worst case NOx emissions from coal-fired plants is 4.5 lbs/MWh, which is equivalent to 1.5 g/hp-hr. The coal-fired plants produce a lot more NOx emissions than the gas field sources do: 160,264 tons/year compared to 38,632 tons/year. A 5% reduction of NOx emissions from the coal-fired plants is the same as a 21% reduction in NOx from gas field sources. 6. We recommend that the Task Force evaluate on-site lean-burn electric generators as an alternative power source for electric compression.	
The SUGF recommends further research and testing of this mitigation option to help determine the amount of emissions reduction that can be accomplished on a continual, reliable basis. If technology could be developed and maintained on a regular basis, this option could prove to be valuable in retrofitting existing rich burn units.	Use of NSCR for NOx Control on Rich Burn Engines
In the section Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines it is stated in the Assumptions (p. 13): "Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines." The term "replacement" is not used, only "new" engines. What is the CE workgroups understanding related to what type of engines would fall under the replacement category, and was this type of engine considered in the assumptions as being retrofitted to meet the interim recommendation of 2 g/hp/hr? Engine Size < 100 hp Case 1 (p. 14): It is stated that "it was assumed that NSCR for this situation would reduce NOx emissions by 50 percent in Colorado and New Mexico and would result in a NOx emission factor of 6.7 g/hp-hr in Colorado and 8.0 g/hp-hr in New Mexico." What is the basis for this assumption? The 2 g/hp-hr interim recommendation for new and replacement engines 300 hp and less (excluding engines less than 40 hp) has been in place since '05, which is almost 3 years ahead of the NSPS implementation date. Does the CE Workgroup have any information on how much impact this interim recommendation, as implemented through BLM/USFS APDs, has had on the average NOx emission factor from the current engine fleet in the 4 Corners area. Tables 6 and 7: Can some narrative be added that explains how emissions reductions are calculated and what each column in the tables represents? Why is table 6 (CO) different from table 7 (NM)? It is unclear how some of the emission reduction values have been calculated in tables 6 and 7. For example, in table 6 why is the emission reduction for < 100 Hp engines 130 TPY instead 143 TPY (50% x 286 TPY)?	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
1. Test data on small two-stroke NSCR retrofitted engines (Ajax DP-115) show NSCR can achieve large NOx emission reductions between 79% and 93% (Chapman, 2004a). On four stroke engines Chapman (2004b) indicates that "these catalyst systems reduce NOX emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent. NOx levels in the range of 0.1 to 1.0 g/bhp-hr have been achieved." Although this is consistent with the statement in the Draft Report that NSCR can achieve NOx emissions of less than 2 g/hp-hr, tighter control levels can certainly be achieved in retrofitting rich burn engines with a well controlled NSCR system. 2. Not all rich-burn engines would need to be retrofitted to NSCR to achieve the reductions postulated in the Draft Report. For example, if 57% of the under-100-hp engines in New Mexico were retrofitted with NSCR, which achieves less than 2 g/hp-hr NOx emissions (this is a conservative number, since NOx emissions that are well under 1 g/hp-hr are possible), then the overall emissions rate for that class of engine would decrease from 16 g/hp-hr to 8 g/hp-hr. According to Table 7 in the Draft Report, this would mitigate 6337 tons/yr of NOx (6694 tons/yr with growth). Since only 57% of the engines in this classification would need to be retrofitted, a retrofit kit would need to be developed only for the most common engine model (or a few models, at most.) This would save the expense of engineering development for engine models that have only a few examples represented in the Four Corners area and would concentrate the engineering effort where it would do the greatest amount of good. If more that 57% of the engines were controlled at the 2 g/hp-hr level, then more that 6337 tons/yr of NOx would be mitigated, but the incremental cost per tons/yr of NOx would be higher than that of the first 6337 tons/yr. It should also be noted that if the 57% of engines with NSCR controlled NOx at the 1 g/hp-hr rather than 2 g/hp-hr, 6773 tons/yr of NOx world be mitigated. This is an additional 436 tons/yr. A number of issues are identified with the use of NSRC on small engines. All of these issues, including ammonia formation, can be eliminated or minimized through use of a NSCR retrofit package that includes all the right components. The appropriate NSCR retrofit kit should include: - A 3-way catalytic converter - Exhaust oxygen sensor - Replace existing carburetor with a controllable air/fuel ratio (AFR) controller device. The ratio of an engine's actual AFR to the stoichiometric AFR for the fuel being used is referred to as the Lambda parameter. To ensure that exhaust bound O2 comprises no more that 0.5% (by volume) of the total engine exhaust, rich burn engines operate at λ's of between 0.988 and 0.992 (Chapman, 2004b). (For engines burning clean, dry natural gas, the air to fuel ratio (AFR) for stoichiometry is ~16.1:1, Chapman, 2004a). - Computerized control using feedback from the exhaust oxygen sensor to control the air/fuel ratio λ's of between 0.988 and 0.992 with the retrofitted NSCR system. - Exhaust gas recirculation (EGR) and controllable ignition timing could also be included and controlled by the same computer. Both EGR and retarded ignition timing reduce engine-out NOx emissions and enhance the effectiveness of the catalyst. Retarded ignition timing also has the effect of increasing exhaust temperature, which will improve the effectiveness of the catalyst at light engine	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
loads. Although considerable engineering effort is required to develop the retrofit kit, it needs to be done for only one engine model or a few engine models, at most. In the 3rd parg. under engines < 100 hp, it states; "Also, research indicates that if the AFR drifts off the optimal setting, then NOx emissions may be converted (on an equal basis) to ammonia. If this occurs within the discharge plume of an engine, it may accelerate the conversion of NOx emissions into particulate nitrate. This is the reason that the carburetor must be replaced with a more accurate AFR controller having feedback from an exhaust oxygen sensor. With such a system, accurate AFR control is achieved, and generation of ammonia is not an issue. ____________________________________ Chapman, K., 2004a, Report 6: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, August Chapman, K., 2004b, Report 4: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, January	
The assumption of 50% reduction of NOx in the Draft Report is too pessimistic or small. Other information indicates that NOx reduction greater than 90% is achievable. Another report indicated 95.9% NOx reduction on a 320 kW (430 hp) natural-gas fueled engine. The same report gave costs of $2,205-$3,684 per ton of NOx removed. This is considerably less than the $10,300 per ton of NOx removed indicated in the Draft Report. Another report indicated that the cost of SCR on reciprocating natural-gas engines varied from $30-$250 per horsepower with no correlation to engine size. Considering that the date of the fourth report is 1990, one reason for the variation in cost may be lack of experience on the part of some installers. Using the same methodology that was used in the Draft Report, but allowing a 90% NOx reduction on new engines instead of 50% gives a reduction of 1789 tons/year (16.5% reduction of overall NOx) in Colorado and a reduction of 2015 tons/year (4.6% reduction of overall NOx in New Mexico. The 90% NOx reduction should be achievable with good operation and maintenance practice in light of the 95.9% NOx reduction already achieved in the field. These figures were for new engines greater than 500 hp. Since the reported engine was smaller than 500 hp, the same calculation was performed for new engines greater than 300 hp. These gave a reduction of 2,109 tons/year (19.5%) in Colorado and 2502 tons/year (5.8%) in New Mexico. The engines with SCR would have NOx emissions of about 0.1 g/hp-hr. ____ 1. Jim McDonald and Xavier Palacios, "Compressor Tech 2: SCR for Gaz de France," Miratech Corporation, Tulsa, OK, December 1, 2002. 2. Johnson Matthey Corp., "Maximum NOx Control for Stationary Diesel and Gas Engines," brochure number "jm_brochure_scr_062306b.pdf". 3. Ravi Krishnan, RJM Corp., "Urea-based SCR technology achieves 12 ppm NOx on natural gas engine," PennWell Power Group Online Article available at http://pepei.pennet.com/Articles/Article_Display.cfm?ARTICLE_ID=156191,	Use of SCR for NOx Control on Lean Burn Engines

Comment	Mitigation Option
October 1, 2002. 4. G.S. Shareef and D.K. Stone, "Evaluation of SCR NOx controls for small natural gas-fueled prime movers. Phase 1. Topical Report," report number PB-90-270398/XAB; DCN-90-209-028-11; GRI-5089-254-1899, Radian Corp., Research Triangle Park, NC, July 1, 1990.	
The first paragraph of the section on Next Generation RICE Stationary Technology in the Draft Report does not give adequate weight to the importance of next generation technology. As emissions regulations become tighter (e.g., 0.2 g/hp-hr NOx in 2010), those limits will become increasingly difficult to meet with existing technology. Continuing research on advanced technologies is necessary to ensure than ever tighter limits in the future can be met. Three of the technologies listed below, NOx trap catalysts, laser ignition, and HCCI, are close to meeting the 0.2 g/hp-hr limit by themselves. Two of the technologies, laser ignition and HCCI, may be able to meet the 0.2 g/hp-hr limit without aftertreatment. With aftertreatments they may be able to meet an even lower limit. NOx trap catalysts are an aftertreatment that offers the same performance as SCR, but with potentially lower cost. Air separation membranes may be used in combination with other technologies to outperform the 0.2 g/hp-hr limit. NOx trap catalysts are similar in performance to SCR, that is they can reduce more than 90% of the engine-out NOx to achieve less than 1 g/hp-hr NOx emissions.[1] The estimates of NOx abatement used in the Cumulative Effects SCR section of the draft report may be used as a guide to the abatement potential of NOx trap catalysts. The cost is expected to be less than that of SCR because ammonia or urea is not used as a reductant. Instead, some of the fuel is used as a reductant. The increase in fuel consumption may be up to 8%, but is typically about 4%. Air separation membranes used to deplete oxygen from the intake air have an effect on NOx emissions that is similar to that of exhaust gas recirculation (EGR) in rich-burn and diesel engines. Combined with ignition retardation, a reduction in engine-out NOx of up to 40% can be expected.[2,3] For engines in the 300-500 hp range, air separation membranes with ignition retard could reduce overall NOx emissions to 2 g/hp-hr in both Colorado and New Mexico. For the 100-300 hp range, these technologies could reduce overall NOx emissions from 16.3 to 10 g/hp-hr in Colorado and from 12.5 to 7.5 g/hp-hr in New Mexico. For engines under 100 hp, the technologies could reduce overall NOx emissions from 13.4 to 8 g/hp-hr in Colorado and from 16 to 9.6 g/hp-hr. Laser ignition may be able to reduce NOx emissions by as much as 70% in lean burn engines.[4] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. Additional development and testing will be required to verify the reduction of NOx emissions. There is little information in the literature about lean NOx catalysts used with lean burn natural gas engines. Information about lean NOx catalysts used with diesel engines indicates NOx reductions of 10-40% depending on whether fuel is used as a reductant.[5,6] NOx reductions for lean burn natural gas engines is expected to be similar. Although researchers are attempting to improve the conversion efficiency of lean NOx catalysts, their current low performance makes them unsuitable for the short term. Only a few experimental measurements of NOx from homogeneous-charge	Next Generation Stationary RICE Technology

Comment	Mitigation Option
compression-ignition (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[7] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[8] Whether HCCI technology can be applied to all engine types and sizes is not known. In addition, the ultimately achievable NOx emissions from such engines is not known. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. ______________________________ 1 James E. Parks II, Douglas Ferguson III, and John M. E. Storey, "NOx Reduction With Natural Gas for Lean Large-Bore Engine Applications Using Lean NOx Trap Aftertreatment." Oak Ridge National Laboratory, 2360 Cherahala Blvd., Oak Ridge, TN 37932. 2 K. Stork and R. Poola, "Membrane-Based Air Composition Control for Light-Duty Diesel Vehicles: A Cost and Benefit Assessment," Report Number ANL/ESD/TM-144, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, IL 60439, October 1998. 3 Joe Kubsh, "Retrofit Emission Control Technologies for Diesel Engines," NAMVECC 2003, Manufacturers of Emission Controls Association, www.meca.org, Chattanooga, TN, November 4, 2003. 4 B. Bihari, S. B. Gupta, R. R. Sekar, J. Gingrich, and J. Smith, "Development of Advanced Laser Ignition System for Stationary Natural Gas Reciprocating Engines," ICEF2005-1325, ASME-ICE 2005 Fall Technical Conference, Ottawa, Canada, 2005. 5 Joe Kubsh, op.cit. 6 Carrie Boyer, Svetlana Zemskova, Paul Park, Lou Balmer-Millar, Dennis Endicott, and Steve Faulkner, "Lean NOx Catalysis Research and Development", Caterpillar Inc., presented at the 2003 Diesel Engine Engineering Research Conference. 7 Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 8 Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.	
The SUGF recommends further examination of the above listed mitigation options as particulates associated with each option contribute to local visibility issues.	Automation of Wells to Reduce Truck Traffic Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Monitoring

MONITORING: PREFACE

Overview

The charter for the Monitoring Workgroup was as follows:

> "The monitoring workgroup will review information provided on existing monitoring networks, and then identify data gaps and options for additional monitoring in cooperation with the other work groups. A gap analysis and trends analysis will be the basis for identifying options for additional monitoring. The monitoring workgroup will identify potential funding sources and develop a holistic monitoring strategic plan for the region."

Group Membership

The Monitoring Group was quite diverse. Members included private citizens from the Durango-Cortez-Aztec area, National Park Service personnel, U. S. Forest Service personnel, the Director of Research and Education at Mountain Studies Institute, a University of Denver graduate student, Tribal air quality personnel (Southern Ute and Navajo Nation), a private consulting hydrologist, air quality staff from two state agencies (New Mexico and Colorado), and personnel from two EPA regions (VI and VIII), among others.

Scope of Work

The following scope of work, including "specific tasks" and "discussion" for the Monitoring Group, was established at the onset of the Task Force.

Specific Tasks

D. Identify existing monitoring networks located in the Four Corners study area. Review information provided by these networks to identify data gaps.
E. Conduct data analyses to determine pollutant trends within the Four Corners study area.
F. Using the gap analysis and trend analysis, identify options for additional monitoring.
G. Incorporate public input when developing a monitoring strategy.
H. Identify potential funding sources for additional monitoring sites.
I. Develop final monitoring strategies for the Four Corners study area.

Discussion

The work group examined the various agency monitoring networks to determine present monitor locations and types, and pollutants or parameters being measured. Using this evaluation the work group identified locations within the study area that lack adequate representation in terms of pollutant data. Available data from the monitoring networks were analyzed to establish pollutant trends. The method and extent of establishing additional monitoring capabilities was dictated by the results from the network studies and from the data analyses. Public input was also addressed during the consideration of potential monitoring site locations. Once it had been established where monitoring sites were needed and what pollutants or parameters were to be measured, the work group identified potential funding sources.

Task 1

In identifying the existing monitoring networks located in the Four Corners study area, a matrix was developed. The matrix attempted to list all known air pollutant monitoring sites and meteorological monitoring sites within the study area. The type of site and the parameters measured at that site were listed in the matrix. The matrix was comprised of four spreadsheets; one having "site information", one having the "criteria sites", one having the "deposition sites", and one having the "meteorological sites".

Task 2

Data from agency databases were used to generate wind and pollution roses, and to generate graphs of pollutant trends. "Overlays" of pollution roses on both political boundary maps and on topographic maps have been produced. The trend graphs plot various pollutant concentrations since 1990.

Task 3

Once the gap analysis and the data analyses had been conducted, the work group assessed the types of monitors required and optimal site locations in the Four Corners study area.

Task 4

Because public sentiment and concern regarding air quality was of great importance to the Four Corners Air Quality Task Force, available public input was considered prior to any final suggestions of site location and type. Some of this input came from public citizens who are part of the task force.

Task 5

To provide the public with some idea of what it takes to set up a new monitoring site, two spreadsheets were created to show both capital and operating costs of two different agency sites. The work group identified potential funding sources for additional monitoring sites.

Task 6

A variety of monitoring strategies/suggestions were developed. These included ozone and ozone precursors, mercury, nitrate and sulfate, and visibility.

EXISTING MONITORING NETWORKS

Monitoring Site Matrix Narrative

The Four Corners Area Monitoring Site Matrix is an attempt to list all of the various air quality monitoring sites in the Four Corners area as well as the predominant meteorological monitoring sites. The following explanations refer to the major column headers of the various matrix pages.

Monitoring Programs

All of the air quality programs are represented in the matrix (some sites are under multiple programs) and are listed below. The following descriptions of the programs are from each program's web site:

ARM-FS: Air Resource Management, USDA Forest Service

The Real-Time Images section features live images and current air quality conditions from USDA-FS monitoring locations throughout the United States. Digital images from Web-based cameras are updated every 15 to 60 minutes. Near real-time air quality data and meteorological data are also provided to distinguish natural from human-made causes of poor visibility, and to provide current air pollution levels to the public.

CASTNET: Clean Air Status and Trends Network, EPA

CASTNET provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone and other forms of atmospheric pollution. CASTNET is considered the nation's primary source for atmospheric data to estimate dry acidic deposition and to provide data on rural ozone levels. Used in conjunction with other national monitoring networks, CASTNET can help determine the effectiveness of national emission control programs.

Each CASTNET dry deposition station measures:

- weekly average atmospheric concentrations of sulfate, nitrate, ammonium, sulfur dioxide, and nitric acid;
- hourly concentrations of ambient ozone levels; and
- meteorological conditions required for calculating dry deposition rates.

CoAgMet: Colorado Agricultural Meteorological Network

In the early 1990's, two groups on the Colorado State campus, the Plant Pathology extension specialists and USDA's Agricultural Research Service (ARS) Water Management Unit, discovered that they had a mutual interest in collecting localized weather data in irrigated agricultural area. Plant pathology used the data for prediction of disease outbreaks in high value crops such as onions and potatoes, and ARS used almost the same information to provide irrigation scheduling recommendations.

To leverage their resources, these two formed an informal coalition, and invited others in the ag research community to provide input into the kinds and frequency of measurements that would be most useful to a broad spectrum of agricultural customers. A standardized set of instruments was selected, a standard datalogger program was developed, and a fledgling network of some eight stations was established in major irrigated areas of eastern Colorado. As interest grew and funds were made available, primarily from potential users, more stations were added.

Initially, stations were located near established phone service to allow daily collection of data. Soon, cellular phone service began to become widely available, and the group determined that this methodology was a reliable and inexpensive method of data recovery. Commercial software was used to download data from the growing list of stations shortly after midnight to a USDA-ARS computer, from which it was then distributed to interested users via answering machine, automated FAX and satellite downlink (Data Transmission Network).

As the network grew, Colorado Climate Center at Colorado State became interested in these data, and subsequently took over the daily data collection and quality assessment. CCC added internet delivery and a wide range of data delivery options, and continues to improve the user interface in response to a growing interest in these data.

IMPROVE: Interagency Monitoring of Protected Visual Environments

Recognizing the importance of visual air quality, Congress included legislation in the 1977 Clean Air Act to prevent future and remedy existing visibility impairment in Class I areas. To aid the implementation of this legislation, the IMPROVE program was initiated in 1985. This program implemented an extensive long term monitoring program to establish the current visibility conditions, track changes in visibility and determine causal mechanism for the visibility impairment in the National Parks and Wilderness Areas.

NADP/NTN: National Atmospheric Deposition Program, National Trends Network
The National Atmospheric Deposition Program/National Trends Network (NADP/NTN) is a nationwide network of precipitation monitoring sites. The network is a cooperative effort between many different groups, including the State Agricultural Experiment Stations, U.S. Geological Survey, U.S. Department of Agriculture, and numerous other governmental and private entities. The NADP/NTN has grown from 22 stations at the end of 1978, our first year, to over 250 sites spanning the continental United States, Alaska, and Puerto Rico, and the Virgin Islands.

The purpose of the network is to collect data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly according to strict clean-handling procedures. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium).

NADP/MDN: National Atmospheric Deposition Program, Mercury Deposition Network
The Mercury Deposition Network (MDN), currently with over 90 sites, was formed in 1995 to collect weekly samples of precipitation which are analyzed by a prominent laboratory for total mercury. The objective of the MDN is to monitor the amount of mercury in precipitation on a regional basis; information crucial for researchers to understand what is happening to the nation's lakes and streams.

NWS: National Weather Service
Feb. 9, 2005 - The NOAA National Weather Service is celebrating its 135th anniversary amid a renewed commitment to preserve its history.

On February 9, 1870, President Ulysses S. Grant signed a joint resolution of Congress authorizing the Secretary of War to establish a national weather service. Later that year, the first systematized, synchronous weather observations ever taken in the U.S. were made by "observer sergeants" of the Army Signal Service.

Today, thousands of weather observations are made hourly and daily by government agencies, volunteer/citizen observers, ships, planes, automatic weather stations and earth-orbiting satellites.

"Since the beginning, the mission of the National Weather Service to protect life and property has been and remains to be the top priority," said Brig. Gen. David L. Johnson, U.S. Air Force (Ret.), director of NOAA's National Weather Service. "Advances in research and technology through the decades have allowed the NOAA National Weather Service to create an expanding observational and data collection network that tracks Earth's changing systems."

RAWS: Remote Automated Weather Stations
There are nearly 2,200 interagency Remote Automated Weather Stations (RAWS) strategically located throughout the United States. These stations monitor the weather and provide weather data that assists land management agencies with a variety of projects such as monitoring air quality, rating fire danger, and providing information for research applications.

SLAMS: State/Local Air Monitoring Stations
These ambient air monitoring sites are designated by EPA as State/Local Air Monitoring Stations (SLAMS). Pollutants monitored are the criteria pollutants, and include ozone, particulate matter, carbon monoxide, lead, sulfur dioxide, and oxides of nitrogen.

SPMS: Special Purpose Monitoring Stations
Special Purpose Monitoring Stations provide for special studies needed by the State and local agencies to support State implementation plans and other air program activities. The SPMS are not permanently established and, can be adjusted easily to accommodate changing needs and priorities. The SPMS are used to supplement the fixed monitoring network as circumstances require and resources permit. If the data from SPMS are used for SIP purposes, they must meet all QA and methodology requirements for SLAMS monitoring.

Tribal: Tribal Jurisdiction

These sites are under tribal jurisdiction and are the tribal equivalent to SLAMS sites, monitoring the same criteria pollutants.

Period of Record

The period of record refers to how long a site has been in operation. In some cases, dates refer to monitoring of major parameters at a site.

In the case of the NWS sites, the “start” dates are the dates when the NWS data was inserted into the MesoWest database which is maintained by the University of Utah’s Department of Meteorology.

Distance From

The distances listed refer to the distance from each monitoring site to two representative Four Corners cities; one in Colorado and one in New Mexico. The distances were obtained either from Argonne National Lab’s interactive Four Corners Aerometric Map or Google Maps. Other “site-to-city” distances can be determined by using either map.

Criteria Pollutants

EPA uses six "criteria pollutants" as indicators of air quality, and has established for each of them a maximum concentration above which adverse effects on human health may occur. Explanations of these pollutants can be found on EPA’s “Green Book” website,
http://www.epa.gov/oar/oaqps/greenbk/o3co.html

Meteorological

These columns indicate what meteorological parameters are monitored at a given site. The parameters are: wind (usually speed and direction), temperature (usually 2-meter and 10-meter), delta T (the difference between 2-meter and 10-meter), solar radiation, relative humidity, and precipitation.

Deposition

The parameters refer to those monitored by The National Atmospheric Deposition Program/National Trends Network (NADP/NTN).

The passive ammonia sampling sites are also listed on the “Deposition” page.

Key to Matrix Symbols

The following explanation refers to the various symbols used within the matrix cells.

h: Sampled and/or averaged hourly
1d/3d: Sampled once every three days
1d/6d: Sampled once every six days
w: Sampled weekly
3w: Sampled every three weeks

Monitoring Site General Information

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Substation	SLAMS	16 mi. NW of Farmington, NM	35-045-1005	01/01/72	Present	36.7967	-108.4803	1643	24.2	73.9
Bloomfield	SLAMS	162 Highway 550 ; Bloomfield, NM	35-045-0009	08/01/77	Present	36.7421	-107.9773	1618	19.4	59.8
Navajo Lake	SLAMS	423 Highway 539 ; Navajo Lake, NM	35-045-0018	07/01/05	Present	36.8098	-107.6514	1950	49.3	56.4
Farmington	SLAMS	724 W Animas ; Farmington, NM	35-045-0006	08/01/77	Present	36.7273	-108.2152	1643	0.0	66.7
S.Ute 3 - Bondad	Tribal	7571 Highway 550 ; La Plata County, CO	08-067-7003	04/01/97	Present	37.1025	-107.8703	1920	50.5	19.3
S.Ute 1 - Ignacio	Tribal	County Road 517 ; La Plata County, CO	08-067-7001	06/01/82	Present	37.1389	-107.6317	1981	67.7	25.8
Shamrock Site	ARM-FS IMPROVE	8 mi. NE of Bayfield, CO	08-067-9000 SHMI1	02/01/04 08/01/04	Present Present	37.3038	-107.4842	2351	90.3	34.3
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	Chapin Mesa, Mesa Verde Nat'l Park, Montezuma County, CO	MEV405 MEVE 1 08-038-0101 CO99 CO99	01/10/95 03/05/94 07/23/06 04/28/81 12/26/01	Present Present Present Present Present	37.1984	-108.4907	2165	57.1	54.3
Pagosa Springs – School	SLAMS	309 Lewis St., Pagosa Springs, CO	08-007-0001	08/01/75	Present	37.2681	-107.0211	2168	121.9	74.8
Durango – Courthouse	SLAMS	1060 E. 2nd Ave., Durango, CO	08-067-1001	03/01/87	12/31/06	37.2739	-107.8786	1984	66.9	0.1
Durango – River City	SLAMS	1235 Camino del Rio, Durango, CO	08-067-0004	09/01/85	Present	37.2769	-107.8806	1985	66.8	0.3
Durango – Tradewinds	SLAMS	1455 S. Camino del Rio, Durango, CO	08-067-0009	10/30/03	04/06/05	37.2187	-107.8516	1973	63.1	3.9
Durango – Cutler	SLAMS	177 Cutler Dr., Durango, CO	08-067-0010	10/30/03	04/30/06	37.3082	-107.8456	1992	70.9	4.3
Durango – Grandview	SLAMS	56 Davidson Rd., Durango, CO	08-067-0011	07/01/04	12/31/06	37.2295	-107.8267	2044	67.6	6.8
Telluride	SLAMS	333 W. Colorado Ave., Telluride, CO	08-113-0004	03/01/90	Present	37.9375	-107.8117	2694	140.6	76.3
Durango Mt. Resort	Other	Hwy. 550 & Purgatory Drive	---	10/11/02	Present	37.6314	-107.8076	2665	105.1	38.9
Wolf Creek Pass	NADP/NTN	Mineral County, CO	CO91	05/26/92	Present	37.4686	-106.7903	3292	148.8	98.6
Molas Pass	NADP/NTN	San Juan County, CO	CO96	07/29/86	Present	37.7514	-107.6853	3249	121.2	56.4

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Weminuche	IMPROVE	30 mi. N of Durango, CO	WEMI1	03/02/88	Present	37.6594	-107.7999	2750	110.6	44.0
San Pedro Parks	IMPROVE	6 mi E of Cuba, NM	SAPE1	08/15/00	Present	36.0139	-106.8447	2935	133.6	160.4
Fort Defiance	Tribal	Rte. 12 N, Bldg. F-004-051, Fort Defiance, AZ	04-001-1234	01/01/99	Present	35.7460	-109.0717	2090	135.4	200.4
Shiprock Dine College	Tribal	Dine College, GIS Lab, Shiprock, NM	35-045-1233	01/01/03	Present	36.8071	-108.6952	1525	45.0	141.1
Canyonlands NP	CASTNET NADP/NTN IMPROVE	"Island of the Sky" Visitor's Center, Canyonlands Nat'l Park, San Juan County, UT	CAN407 UT09 CANY1	01/24/95 11/11/97 03/02/88	Present Present Present	38.4580	-109.821	1814	239.8	214.6
Arches NP	IMPROVE	14 mi N of Moab, UT	ARCH1	03/02/88	05/16/92	38.7833	-109.5830	1722	253.6	217.2
Moab #6	SLAMS	168 West 400 North, Moab, UT	49-019-0006	10/21/93	6/30/03	38.5795	-109.5540			
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	1 mi. N of park HQ	PET427 PEFO1 04-001-0012	? 03/02/88 10/27/86	Present Present 04/16/92	35.0772	-109.7697	1766	262.9	329.2
Petrified Forest NP (New)	SPMS	SW Entrance; off Rte. 180	04-017-0119	01/01/88	Present	34.8230	-109.8919	1723	265.5	331.5
Rainbow Forest NP	NADP/NTN	Apache County, AZ	AZ97	12/03/02	Present	35.0013	-109.0128	1707	207.5	274.1
Alamosa	NADP/NTN	Alamosa county, CO	CO00	04/22/80	Present	37.4414	-105.8653	2298	221.0	177.6
Great Sand Dunes NP	IMPROVE	Monument HQ, Saguache County, CO	GRSA1	05/04/88	Present	37.7249	-105.5185	2498	258.0	207.1
Big Horn	RAWS	Conejos County, CO	BHRC2	05/13/93	Present	37.0208	-106.2011	2637	175	147
Sand Dunes	RAWS	Alamosa County, CO	SDNC2	06/02/04	Present	37.7267	-105.5108	2537	254	210
Lujan	RAWS	Saguache County, CO	LUJC2	09/13/94	Present	38.2544	-106.5678	3400	214	155
Needle Creek	RAWS	Saguache County, CO	NCKC2	09/05/02	Present	38.3894	-106.5308	2741	227	168
Huntsman Mesa	RAWS	Gunnison County, CO	HMEC2	05/22/91	Present	38.3319	-107.0889	2865	195	135
McClure Pass	RAWS	Gunnison County, CO	MPRC2	06/11/85	Present	39.1267	-107.2842	2761	264	205
Taylor Park	RAWS	Gunnison County, CO	TAPC2	10/27/87	Present	38.9086	-106.6028	3200	268	210
PSF2 Salida 555	RAWS	Chaffee County, CO	SIDC2	05/01/97	Present	38.7856	-105.9569	2932	291	229
Red Deer	RAWS	Chaffee County, CO	RDKC2	05/01/83	Present	38.8272	-106.2117	2660	280	218
Jay	RAWS	Delta County, CO	JAYC2	07/09/84	Present	38.8456	-107.7386	1890	227	168
Blue Park	RAWS	Mineral County, CO	BLPC2	04/24/90	Present	37.7931	-106.7786	3179	167	109
Black Canyon	RAWS	Montrose County, CO	LPRC2	06/04/97	Present	38.5428	-107.6869	2609	195	132
Carpenter Ridge	RAWS	Montrose County, CO	CPTC2	12/17/98	Present	38.4594	-109.0469	2465	195	160
Cottonwood Basin	RAWS	Montrose County, CO	CMEC2	05/23/91	Present	38.5731	-108.2778	2201	194	140

			AQS / Other	Period of Record				Elevation	Distance from: (Km)	
Site	Program	Address	Code	From	To	Latitude	Longitude	(meters)	Farmington	Durango
Nucla	RAWS	Montrose County, CO	NUCC2	05/21/98	Present	38.2333	-108.5617	1786	162	116
Sanborn Park	RAWS	Montrose County, CO	SPKC2	01/29/85	Present	38.1922	-108.2169	2417	153	101
Salter	RAWS	Dolores County, CO	SAWC2	05/30/85	Present	37.6511	-108.5369	2500	101	67
Devil Mtn.	RAWS	Archuleta County, CO	DYKC2	07/27/89	Present	37.2269	-107.3053	2274	92	50
Sandoval Mesa	RAWS	Archuleta County, CO	SDVC2	07/15/99	Present	37.0994	-107.3028	2588	86	53
Big Bear Park	RAWS	La Plata County, CO	BBRC2	08/26/05	Present	37.4961	-107.7294	3170	90	28
Mesa Mtn.	RAWS	La Plata County, CO	MMRC2	11/17/93	Present	37.0564	-107.7086	2249	54	25
SJF1 Durango 555	RAWS	La Plata County, CO	DUFC2	06/01/96	Present	37.3517	-107.9000	2502	72	9
Chapin	RAWS	Montezuma County, CO	CHAC2	09/07/99	Present	37.1994	-108.4892	2172	55	51
Mockingbird	RAWS	Montezuma County, CO	MOKC2	08/24/05	Present	37.4744	-108.8842	1957	99	87
Morefield	RAWS	Montezuma County, CO	MRFC2	11/12/99	Present	37.2972	-108.4128	2383	61	45
Albino Canyon	RAWS	San Juan County, NM	CWRN5	09/27/83	Present	36.9769	-107.6283	2182	55	35
Washington Pass	RAWS	San Juan County, NM	WPSN5	11/19/03	Present	36.0781	-108.8575	2856	86	147
Coyote	RAWS	Rio Arriba County, NM	COYN5	08/07/96	Present	36.0667	-106.6472	2682	149	161
Deadman Peak	RAWS	Rio Arriba County, NM	DPKN5	05/23/00	Present	36.4231	-107.7719	2575	46	129
Dulce #2	RAWS	Rio Arriba County, NM	DLCN5	07/07/05	Present	36.9350	-107.0000	2070	107	79
Jarita Mesa	RAWS	Rio Arriba County, NM	JARN5	04/15/02	Present	36.5558	-106.1031	2683	183	168
Stone Lake	RAWS	Rio Arriba County, NM	STLN5	07/07/05	Present	36.7314	-106.8647	2268	115	103
Zuni Buttes	RAWS	McKinley County, NM	ZNRN5	04/04/06	Present	35.1392	-108.9414	2039	172	236
Alb Portable #2	RAWS	McKinley County, NM	TSO43	11/18/03	Present	35.5264	-107.3211	2481	138	182
Bryson Canyon	RAWS	Grand County, UT	BCRU1	09/03/87	Present	39.2789	-109.2211	1621	283	241
Big Indian Valle	RAWS	San Juan County, UT	BIVU1	09/02/87	Present	38.2244	-109.2783	2121	182	153
Kane Gulch	RAWS	San Juan County, UT	KAGU1	06/20/91	Present	37.5247	-109.8931	1981	165	174
North Long Point	RAWS	San Juan County, UT	NLPU1	08/13/97	Present	37.8547	-109.8389	2646	182	175
Piney Hill	RAWS	Apache County, AZ	QPHA3	11/19/03	Present	35.7611	-109.1675	2469	126	187
Cortez	CoAgMet	9 mi. SW of Cortez, CO	CTZ01	04/24/91	Present	37.2248	-108.6730	1833	67	67
Dove Creek	CoAgMet	4 mi. NW of Dove Creek	DVC01	10/28/92	Present	37.7265	-108.9540	2010	123	104
Towaoc	CoAgMet	Ute Mtn Ute Farm	TWC01	06/30/98	Present	37.1891	-108.9350	1621	78	88
Yellow Jacket	CoAgMet	2.5 mi. NW of Yellow Jacket	YJK01	05/19/91	Present	37.5289	-108.7240	2103	94	77
Yucca House	CoAgMet	Yucca House National Monument	YUC01	01/01/02	Present	37.2478	-108.6870	1821	69	67
Cortez-Montezuma County Airport	NWS	3 mi. SW of Cortez, CO	KCEZ	01/01/97	Present	37.3064	-108.6256	1803	71	7

Site	Program	Address	AQS / Other	Period of Record		Latitude	Longitude	Elevation	Distance from: (Km)	
			Code	From	To			(meters)	Farmington	Durango
Cottonwood Pass	NWS	SW of Buena Vista, CO	K7BM	11/17/04	Present	38.7825	-106.2181	2995	280	215
Durango-La Plata County Airport	NWS	1000 Airport Road; Durango, CO	KDRO	01/01/97	Present	37.1431	-107.7597	2038	60	0
Gunnison-Crested Butte Regional Airport	NWS	519 W Rio Grande; Gunnison, CO	KGUC	01/01/97	Present	38.5333	-106.9333	2340	221	156
Montrose Regional Airport	NWS	2100 Airport Road ; Montrose, CO	KMTJ	01/01/97	Present	38.5050	-107.8975	1755	189	128
Pagosa Springs, Wolf Creek Pass	NWS	NE of Pagosa Springs, CO	KCPW	11/11/03	Present	37.4514	-106.8003	3584	145	95
Saguache Municipal Airport	NWS	2 mi. NW of Saguache, CO	04V	11/17/04	Present	38.0972	-106.1686	2385	227	171
Salida Mountain, Monarch Pass	NWS	W of Salida, CO	KMYP	09/10/03	Present	38.4844	-106.3169	3667	249	185
Telluride Regional Airport	NWS	1500 Last Dollar Road ; Telluride, CO	KTEX	02/05/97	Present	37.9539	-107.9086	2767	135	72
Farmington, Four Corners Regional Airport	NWS	800 Municipal Drive ; Farmington, NM	KFMN	01/01/97	Present	36.7436	-108.2292	1677	0	63
Grants-Milan Municipal Airport	NWS	3 mi. NW of Grants, NM	KGNT	04/11/97	Present	35.1653	-107.9022	1988	160	214
Gallup Municipal Airport	NWS	2111 W Hwy 66 ; Gallup, NM	KGUP	01/01/97	Present	35.5111	-108.7894	1973	133	194
Window Rock Airport	NWS	1 mi. S of Window Rock AZ	KRQE	11/14/99	Present	35.6500	-109.0667	2055	131	190
Moab, Canyonlands Field	NWS	18 mi. NW of Moab, UT	KCNY	01/01/97	Present	38.7600	-109.7447	1388	249	224

ARM-FS : Air Resource Management, USDA Forest Service
CASTNET : Clean Air Status and Trends Network, EPA
CoAgMet : Colorado Agricultural Meteorological Network
IMPROVE : Interagency Monitoring of Protected Visual Environments
NADP/NTN : National Atmospheric Deposition Program, National Trends Network
NADP/MDN : National Atmospheric Deposition Program, Mercury Deposition Network
NWS : National Weather Service
RAWS : Remote Automated Weather Stations
SLAMS : State/Local Air Monitoring Stations
SPMS : Special Purpose Monitoring Stations
Tribal : Tribal Jurisdiction

Criteria Pollutant Sites

Site	Program	Criteria Pollutants							
		O3	SO2	CO	NOx	NO	NO2	PM10	PM2.5
Substation	SLAMS	h	h		h	h	h		
Bloomfield	SLAMS	h	h		h	h	h		
Navajo Lake	SLAMS	h			h	h	h		h
Farmington	SLAMS							1d/6d	1d/3d
S.Ute 3 - Bondad	Tribal	h			h	h	h	ended 9/30/06	
S.Ute 1 - Ignacio	Tribal	h		h	h	h	h	ended 9/30/06	
Shamrock Site	ARM-FS	h			h	h	h		
	IMPROVE		1d/3d		1d/3d			1d/3d	1d/3d
Mesa Verde	CASTNET	h	h		h				1d/3d
	IMPROVE		1d/3d		1d/3d			1d/3d	
	SPMS								
	NADP/NTN								
	ADP/MDN								
Pagosa Springs – School	SLAMS							1d/1d	1d/3d end 12/06
Durango – Courthouse	SLAMS							1d/3d end 12/06	
Durango- River City	SLAMS							1d/3d	
Durango – Tradewinds	SLAMS							1d/6d end 3/05	
Durango – Cutler	SLAMS							1d/6d end 4/06	
Durango - Grandview	SLAMS							1d/3d end 12/06	
Telluride	SLAMS							1d/3d	1d/3d end 12/06
Durango Mt. Resort	Other							h	
Weminuche	IMPROVE							1d/3d	1d/3d
San Pedro Parks	IMPROVE							1d/3d	1d/3d
Fort Defiance	Tribal							1d/6d	
Shiprock Dine College	Tribal							1d/6d	
Canyonlands NP	CASTNET	h	h		h				
	NADP/NTN								
	IMPROVE		1d/3d		1d/3d			1d/3d	1d/3d
Arches NP	IMPROVE		1d/3d		1d/3d				
Moab #6	SLAMS							1d/6d	
Petrified Forest NP (Old)	CASTNET	h	h		h				
	IMPROVE		1d/3d		1d/3d			1d/3d	1d/3d
	SPMS	h							
Petrified Forest NP (New)	SPMS	h							
Great Sand Dunes NP	IMPROVE							1d/3d	1d/3d

See Monitoring Site General Information table for abbreviations
h : Sampled and/or averaged hourly
1d/1d : 24-hour sample taken every day
1d/3d : 24-hour sample taken every 3rd day
1d/6d : 24-hour sample taken every 6th day

Meteorological Sites

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Substation	SLAMS	h	h	h	h		
Bloomfield	SLAMS	h	h	h	h		
Navajo Lake	SLAMS	h	h	h	h		
S.Ute 3 - Bondad	Tribal	h	h	h	h	h	h
S.Ute 1 - Ignacio	Tribal	h	h	h	h	h	h
Shamrock Site	ARM-FS IMPROVE	h	h		h	h	h
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	h	h	h	h	h	
Durango Mt. Resort	Other	h	h	h	h	h	h
Fort Defiance	Tribal	h	h		h	h	h
Shiprock Dine College	Tribal	h	h		h	h	h
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h	h	h	h	
Petrified Forest NP (Old)	CASTNET IMPROVE	h	h	h	h	h	
Petrified Forest NP (New)	SPMS	h	h				
Big Horn	RAWS	h	h		h	h	h
Sand Dunes	RAWS	h	h		h	h	h
Lujan	RAWS	h	h		h	h	h
Needle Creek	RAWS	h	h		h	h	h
Huntsman Mesa	RAWS	h	h		h	h	h
McClure Pass	RAWS	h	h		h	h	h
Taylor Park	RAWS	h	h		h	h	h
PSF2 Salida 555	RAWS	h	h		h	h	h
Red Deer	RAWS	h	h		h	h	h
Jay	RAWS	h	h		h	h	h
Blue Park	RAWS	h	h		h	h	h
Black Canyon	RAWS	h	h		h	h	h
Carpenter Ridge	RAWS	h	h		h	h	h
Cottonwood Basin	RAWS	h	h		h	h	h
Nucla	RAWS	h	h		h	h	h
Sanborn Park	RAWS	h	h		h	h	h
Salter	RAWS	h	h		h	h	h
Devil Mtn.	RAWS	h	h		h	h	h
Sandoval Mesa	RAWS	h	h		h	h	h
Big Bear Park	RAWS	h	h		h	h	h
Mesa Mtn.	RAWS	h	h		h	h	h
SJF1 Durango 555	RAWS	h	h		h	h	h
Chapin	RAWS	h	h		h	h	h
Mockingbird	RAWS	h	h		h	h	h
Morefield	RAWS	h	h		h	h	h

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Albino Canyon	RAWS	h	h		h	h	h
Washington Pass	RAWS	h	h		h	h	h
Coyote	RAWS	h	h		h	h	h
Deadman Peak	RAWS	h	h		h	h	h
Dulce #2	RAWS	h	h		h	h	h
Jarita Mesa	RAWS	h	h		h	h	h
Stone Lake	RAWS	h	h		h	h	h
Zuni Buttes	RAWS	h	h		h	h	h
Alb Portable #2	RAWS	h	h		h	h	h
Bryson Canyon	RAWS	h	h		h	h	h
Big Indian Valle	RAWS	h	h		h	h	h
Kane Gulch	RAWS	h	h		h	h	h
North Long Point	RAWS	h	h		h	h	h
Piney Hill	RAWS	h	h		h	h	h
Cortez	CoAgMet	h	h		h	h	
Dove Creek	CoAgMet	h	h		h	h	
Towaoc	CoAgMet	h	h		h	h	
Yellow Jacket	CoAgMet	h	h		h	h	
Yucca House	CoAgMet	h	h		h	h	
Cortez-Montezuma County Airport	NWS	h	h			h	
Cottonwood Pass	NWS	h	h			h	
Durango-La Plata County Airport	NWS	h	h			h	
Gunnison-Crested Butte Regional Airport	NWS	h	h			h	
Montrose Regional Airport	NWS	h	h			h	
Pagosa Springs, Wolf Creek Pass	NWS	h	h			h	
Saguache Municipal Airport	NWS	h	h			h	
Salida Mountain, Monarch Pass	NWS	h	h			h	
Telluride Regional Airport	NWS	h	h			h	
Farmington, Four Corners Regional Airport	NWS	h	h			h	
Grants-Milan Municipal Airport	NWS	h	h			h	
Gallup Municipal Airport	NWS	h	h			h	
Window Rock Airport	NWS	h	h			h	
Moab, Canyonlands Field	NWS	h	h			h	

See Monitoring Site General Information table for abbreviations
h: Sampled and/or averaged hourly

Deposition Sites

Site	Program	Deposition								
		NH3	pH	SO4	NH4	NO3	Pb	HF	Hg	Ca, Mg, K, Na, Cl
Substation	SLAMS	3w								
Navajo Lake	SLAMS	3w								
S.Ute 3 - Bondad	Tribal	3w								
Mesa Verde	CASTNET									
	IMPROVE									
	SPMS	3w								
	NADP/NTN		w	w	w	w				w
	NADP/MDN								w	w
Wolf Creek Pass	NADP/NTN		w	w	w	w				w
Molas Pass	NADP/NTN		w	w	w	w				w
Canyonlands NP	CASTNET									
	NADP/NTN		w	w	w	w				w
	IMPROVE									
Rainbow Forest NP	NADP/NTN		w	w	w	w				w
Alamosa	NADP/NTN		w	w	w	w				w
Farmington Airport	OTHER	3w								

See Monitoring Site General Information table for abbreviations
w : Sampled weekly
3w : Sampled every 3 weeks

DATA ANALYSIS AND RECOMMENDATIONS

Meteorology and Wind Roses

Background:

Rationale and Benefits:
Meteorology is the science that deals with the study of the atmosphere and its phenomena, especially with weather and weather forecasting. Meteorological conditions are a driving force in many bad pollution events and situations. These include stagnation, inversions and blowing dust. There are a number of components to meteorology, including wind speed, wind direction, temperature, relative humidity, barometric pressure, solar radiation, precipitation and others. Modeling is performed with the various components as part of forecasting for weather conditions as well as for air pollution impacts.

For air pollution, wind speed and wind direction are two of the more important components. These can determine how far pollution can be transported in a certain time period, if stagnation periods exist and what sources may have contributed to the air pollution. Wind roses are a simple visual way to depict wind speed strengths as a function of wind direction for a period of time. Wind roses are based on the direction that the wind is blowing from. Another way of visualizing a wind rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The wind speed is broken down into multiple ranges. The length of each arm of the wind rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of wind speeds of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of wind speed occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Wind roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[1]

Existing meteorological data for the Four Corners region:
Meteorological data are collected at a number of different locations in the Four Corners region. Sites include State and Tribal agencies, the National Weather Service (NWS), the U.S. Forest Service (USFS), the National Park Service (NPS), The Remote Automated Weather Stations (RAWS) network, the Colorado Agriculture Meteorological Network (CoAgMet) and other private groups. Data are available from varying sources, including the U.S. Environmental Protection Agency's Air Quality System[2], the CoAgMet website[3], the New Mexico Environment Department website[4], the NWS website[5], the RAWS website[6] and from direct contact. For wind roses, hourly data (or more frequent) are needed. Ten-meter tall towers are a general standard that is used, though not all networks are set up this way. Maps of the meteorological sites that were used in this analysis are presented below, both for the whole Four Corners region and for a core area. These sites are a limited subset of the total number of possible sites, as can be seen in the site matrix tables in a different section of this overall report.

Wind roses were developed using hourly wind speed and wind direction data from 2006. Annual wind roses were developed as well at daytime (6:00 a.m. – 6:00 p.m.) and nighttime (6:00 p.m. – 6:00 a.m.). These wind roses were then overlaid on both political boundary maps and topographical maps (see annual/daytime/nighttime wind rose maps).

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

Data Gaps:
No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona.

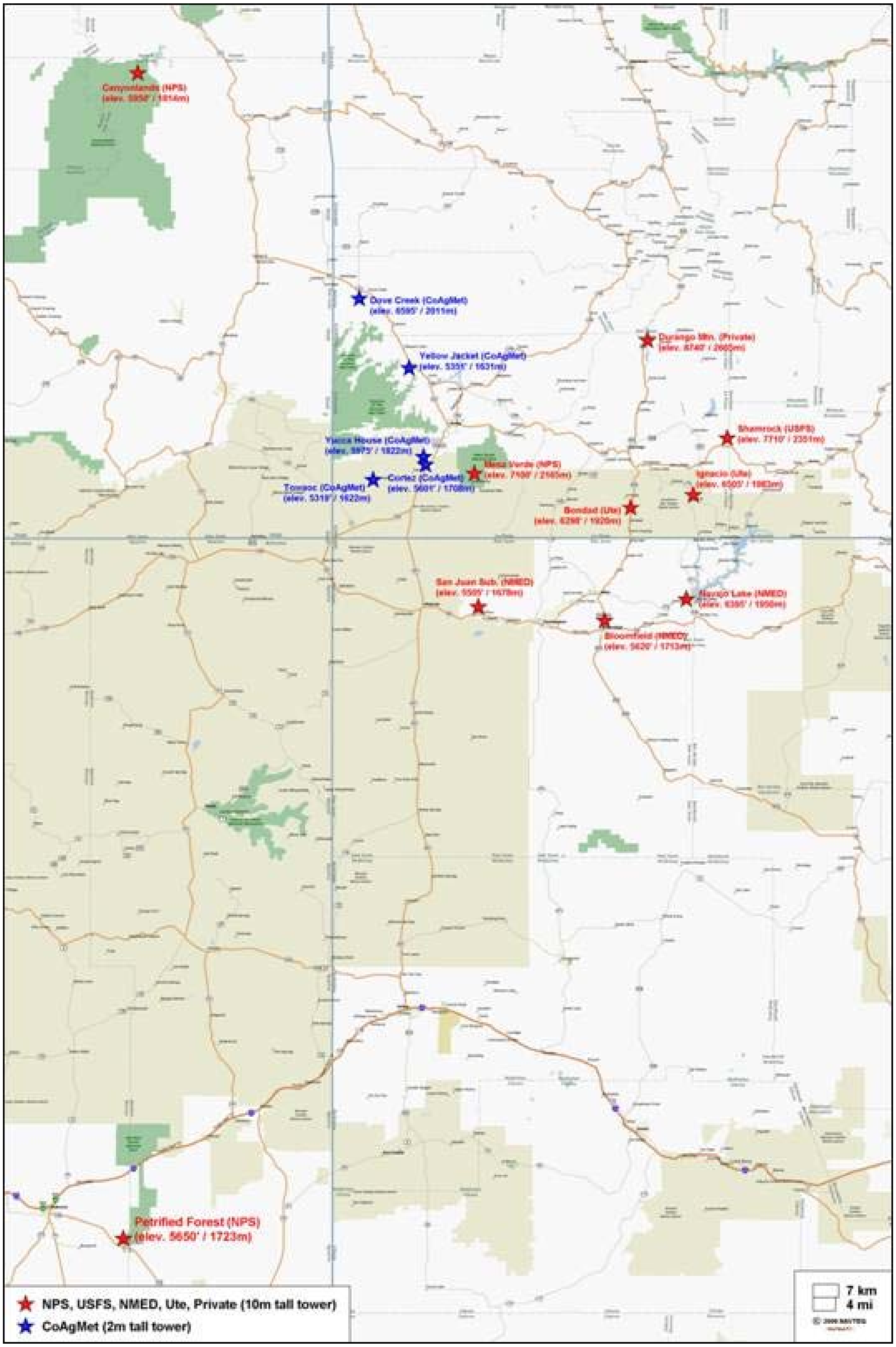
Suggestions for Future Monitoring Work:

No suggestions for additional monitoring of meteorological parameters are currently being proposed.

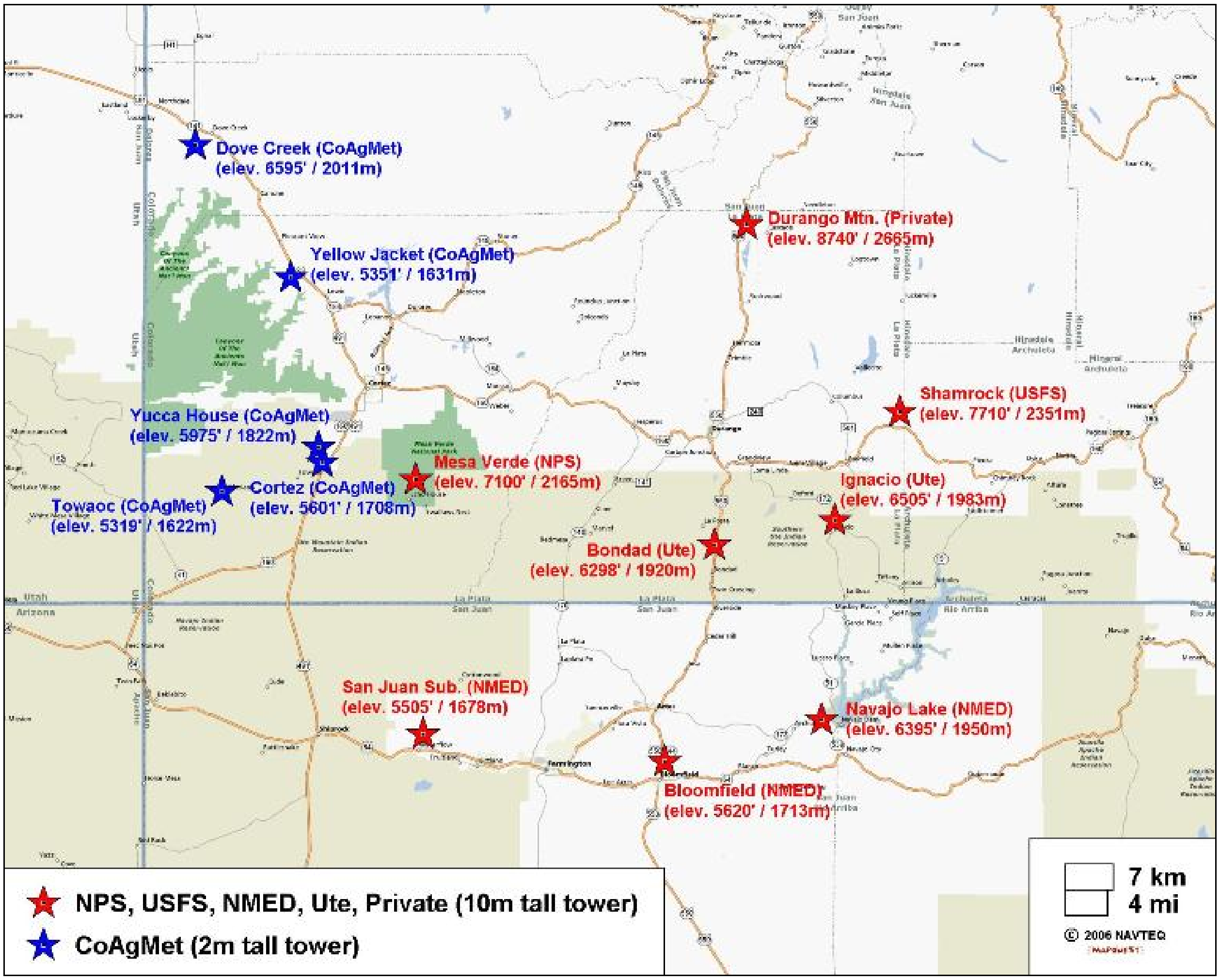
Literature Cited:

1. Lakes Environmental Software. WRPLOT View. http://www.weblakes.com/lakewrpl.html.
2. U.S. Environmental Protection Agency. http://www.epa.gov/air/data/index.html.
3. Colorado State University. Colorado Agriculture Meteorological Network. http://ccc.atmos.colostate.edu/~coagmet/.
4. New Mexico Environment Department. http://air.state.nm.us/.
5. National Weather Service. Automated Surface Observation System. http://www.nws.noaa.gov/asos/.
6. Western Regional Climate Center. Remote Automated Weather System. http://www.raws.dri.edu/index.html.

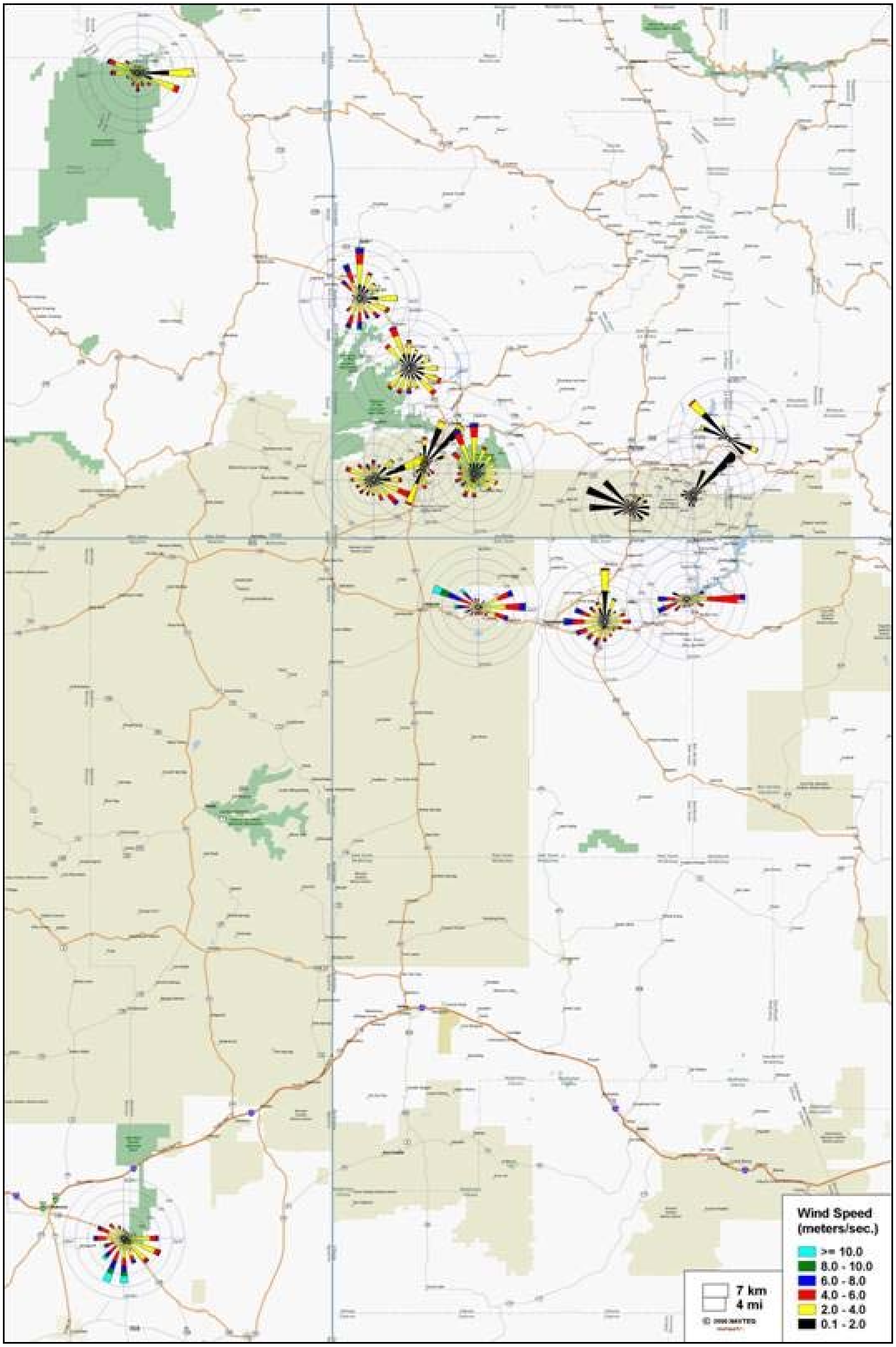
Four Corners --- Meteorological Sites in 2006



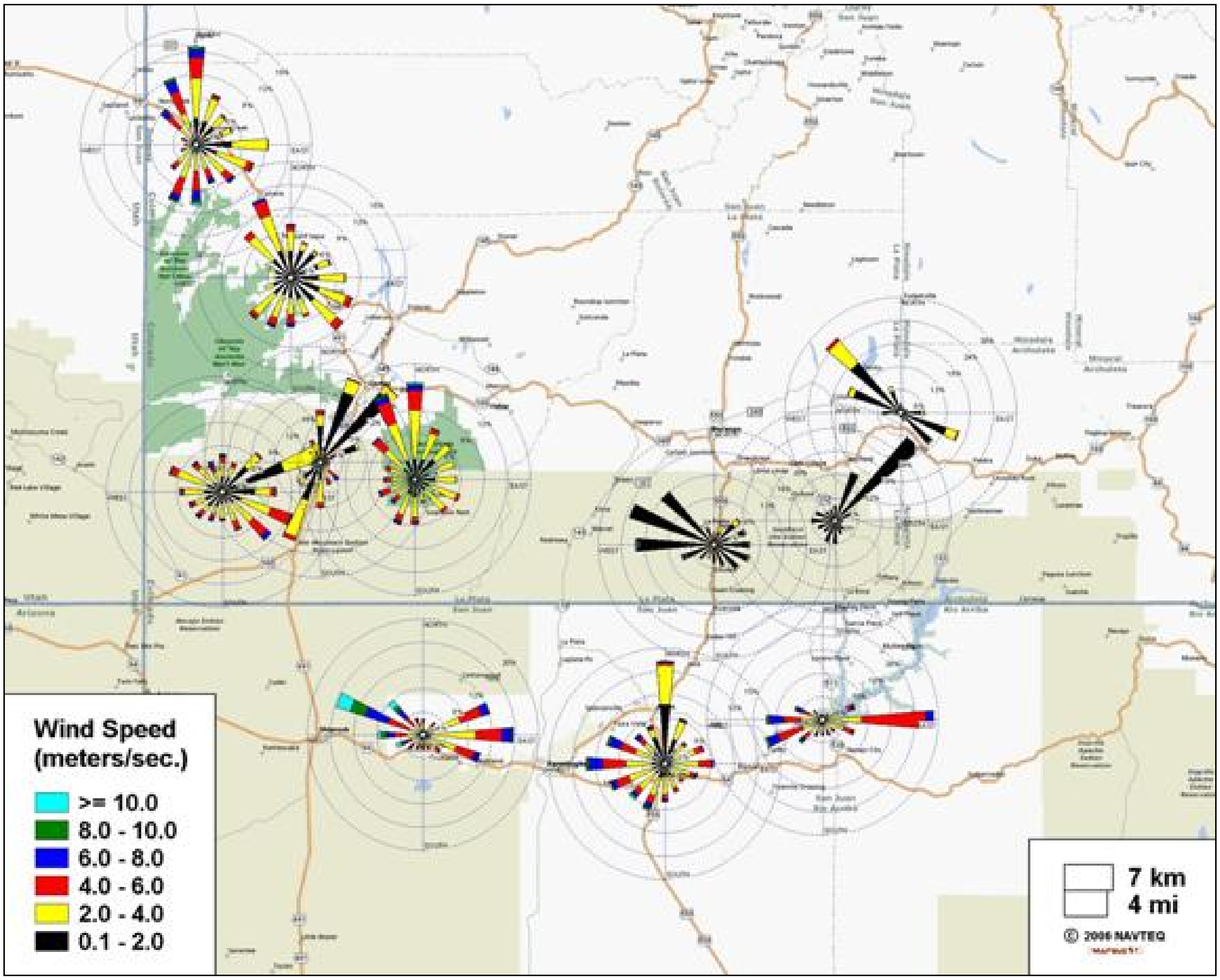
Close-in Four Corners --- Meteorological Sites in 2006



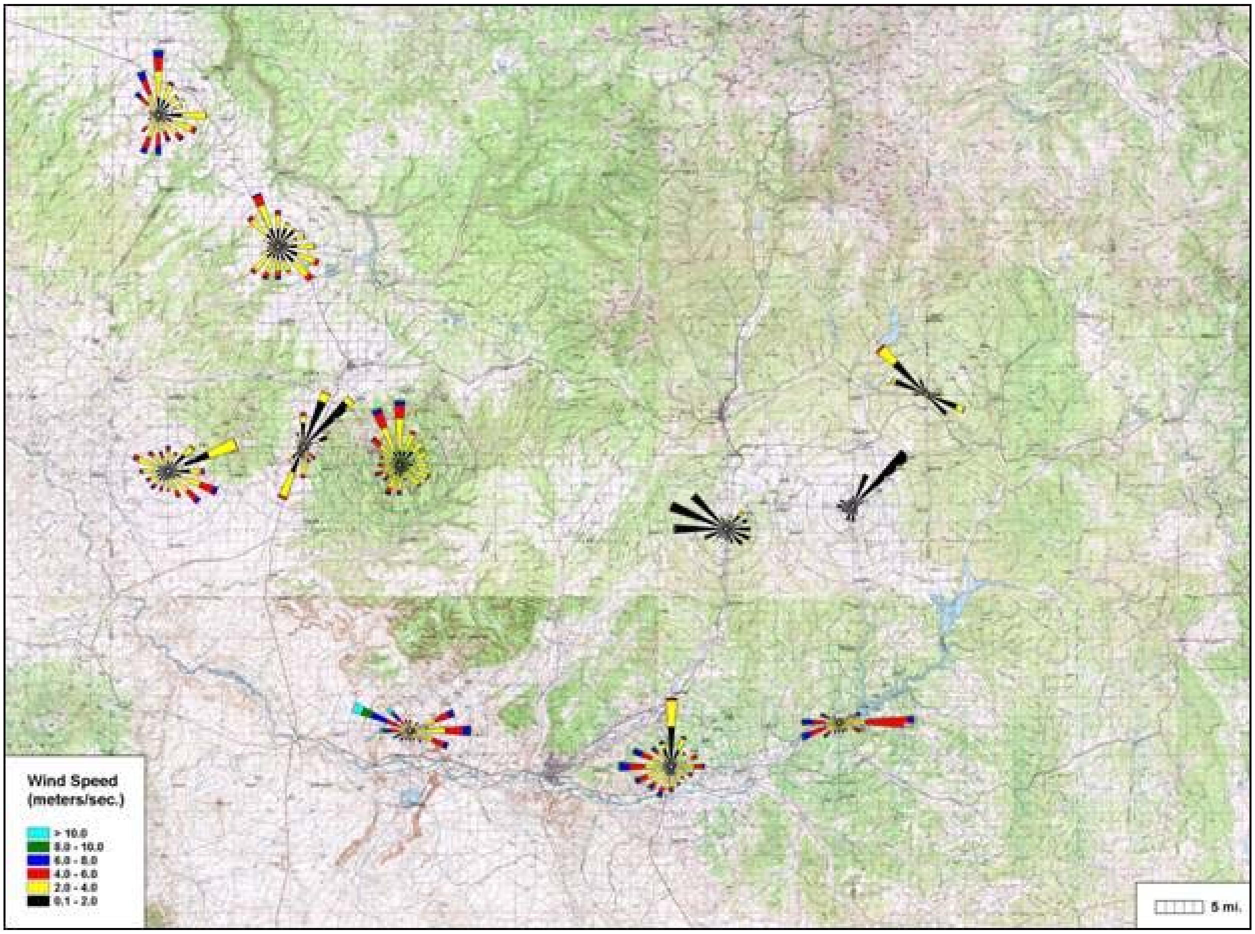
Four Corners --- 2006 Annual Wind Roses



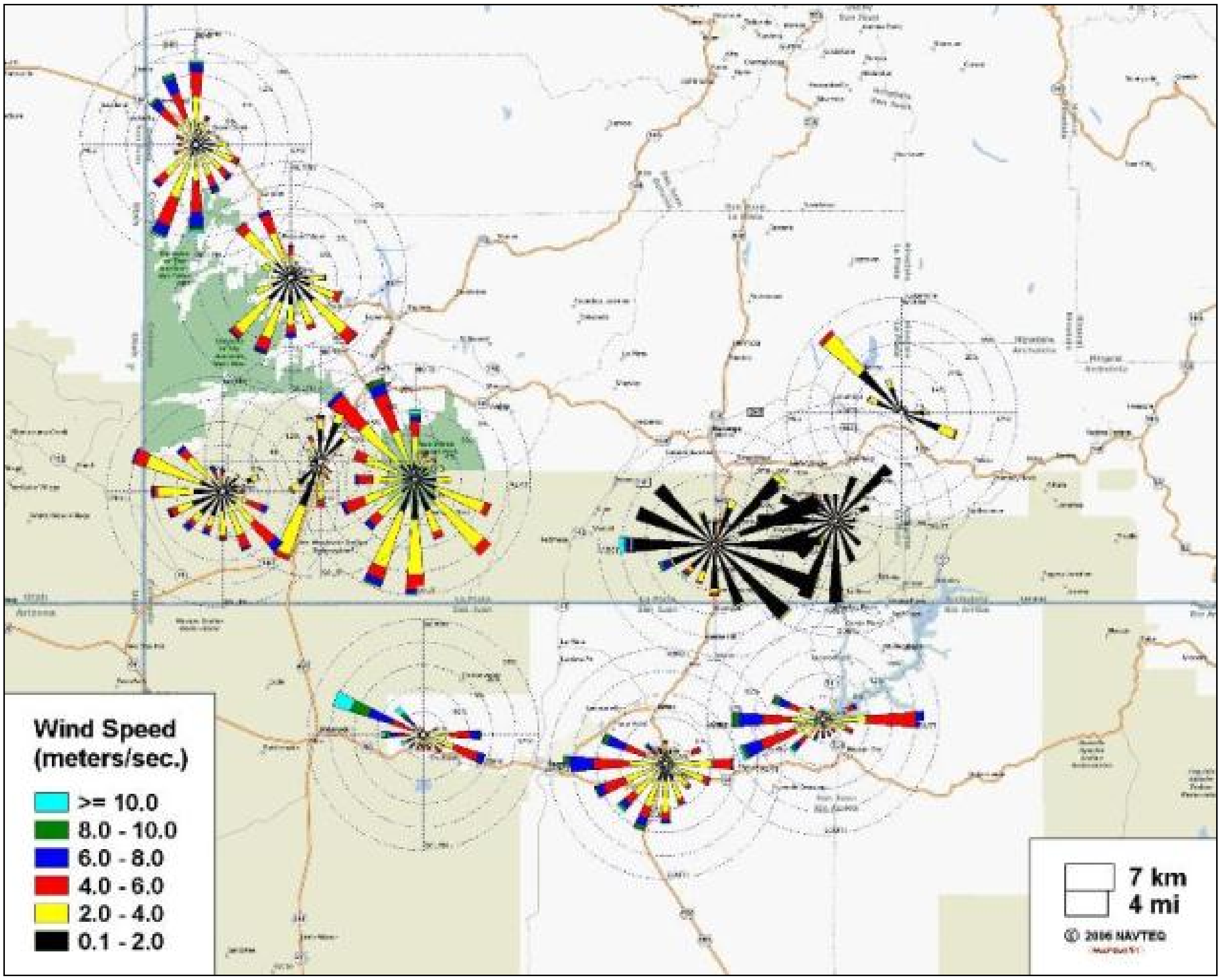
Close-in Four Corners --- 2006 Annual Wind Roses
(Political boundary map)



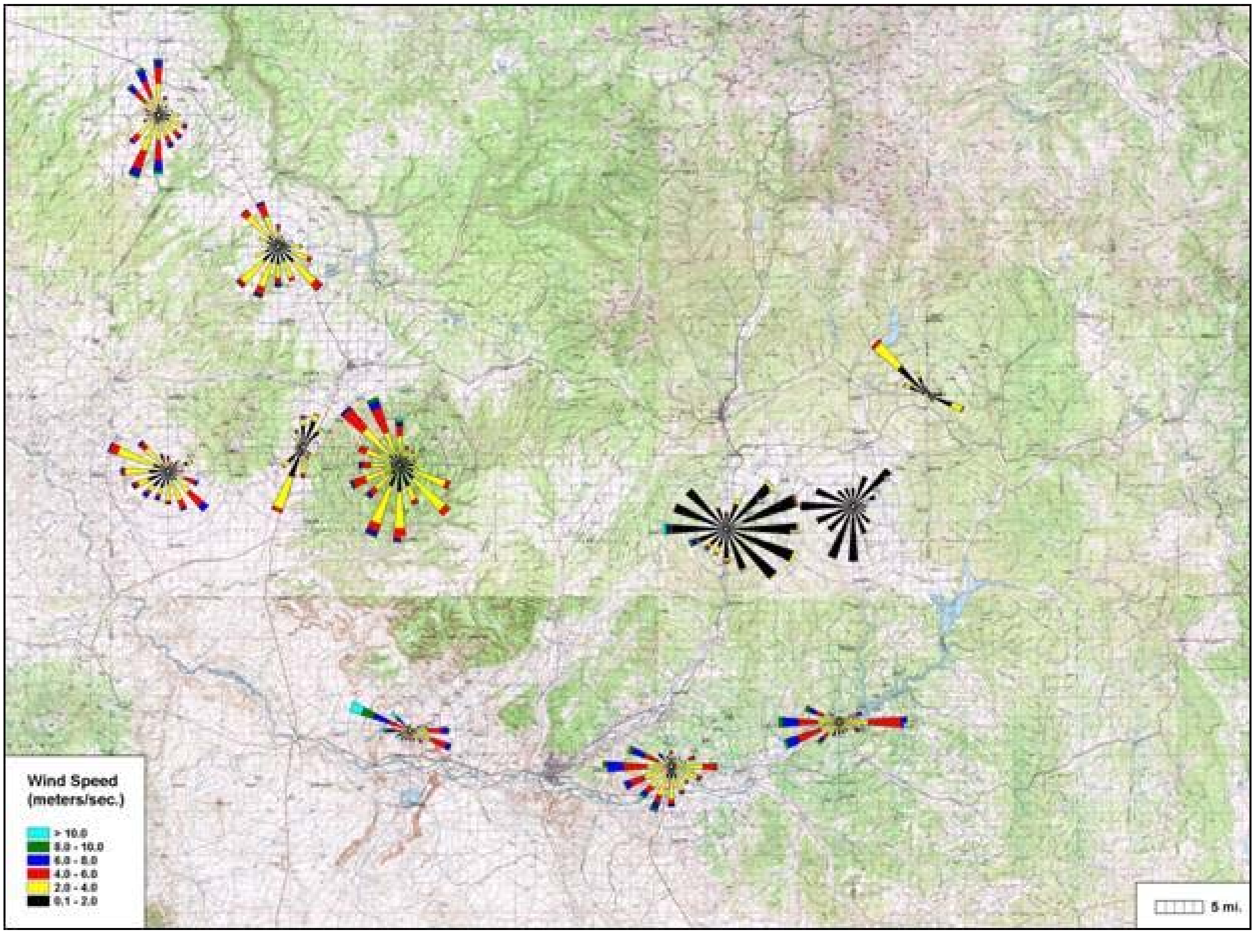
Close-in Four Corners --- 2006 Annual Wind Roses
(Topographic map)



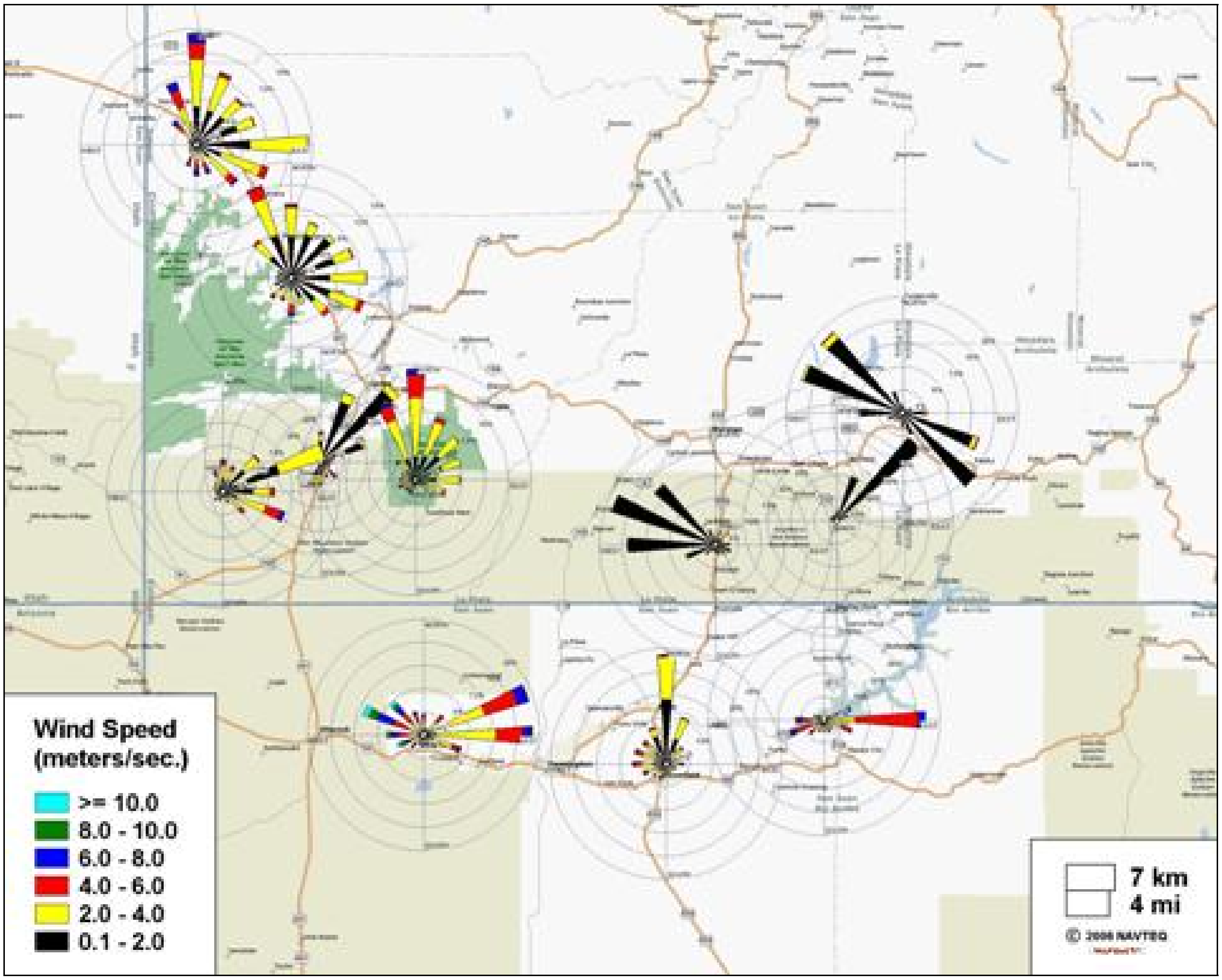
Close-in Four Corners --- 2006 Daytime Wind Roses
(Political boundary map)



Close-in Four Corners --- 2006 Daytime Wind Roses
(Topographic map)



Close-in Four Corners --- 2006 Nighttime Wind Roses (Political boundary map)



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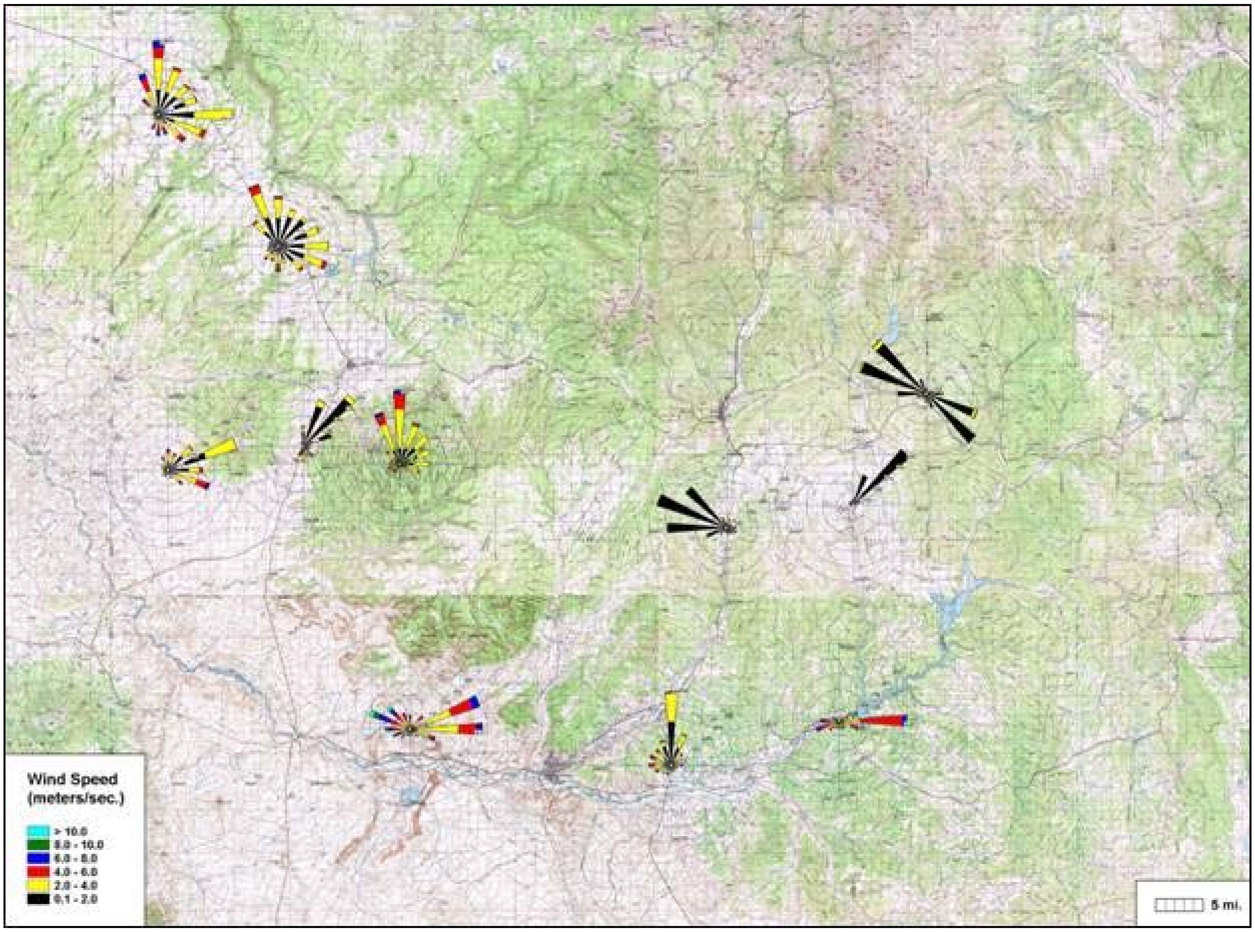
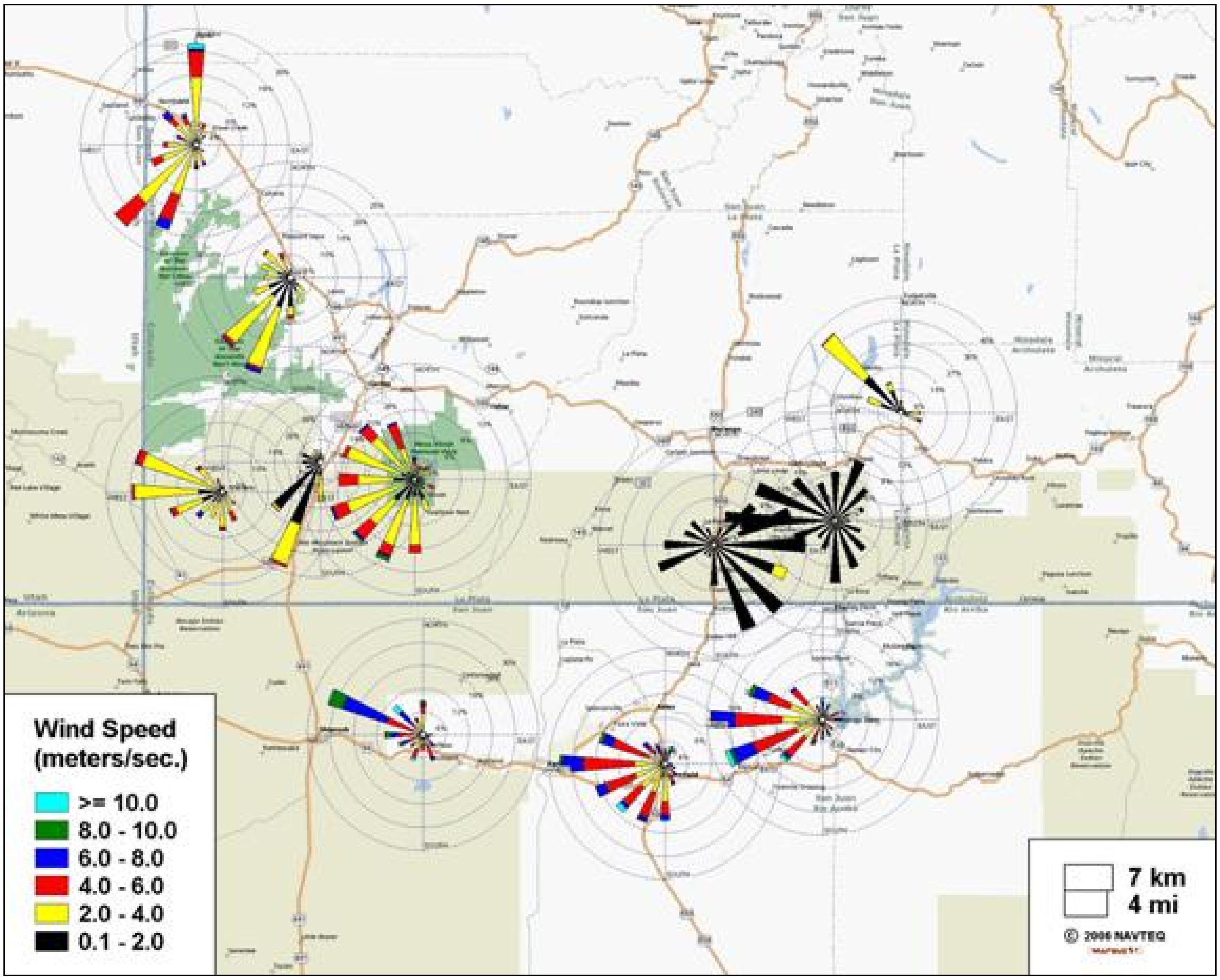
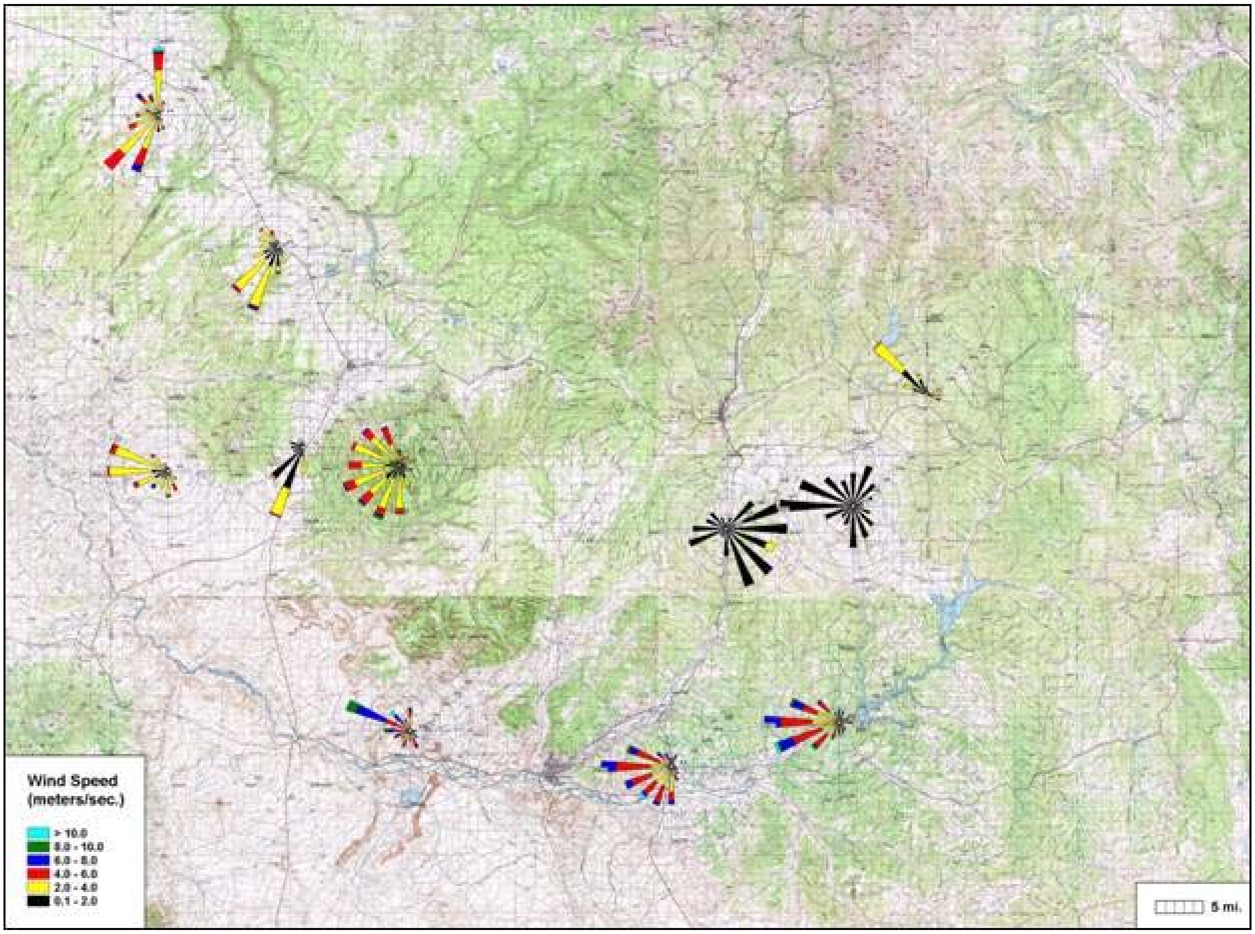
(Topographic map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Political boundary map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Topographic map)



Ozone and Precursor Gases

Background:

Rationale and Benefits:
Ozone is a colorless, odorless and tasteless gaseous pollutant that is both necessary and harmful to human health. In the stratosphere where it occurs naturally, it provides a barrier to ultraviolet radiation. However, at ground-level in the troposphere, ozone is the prime ingredient of smog. When inhaled, ozone can cause acute respiratory problems, aggravate asthma, cause significant temporary decreases in lung capacity, cause inflammation of lung tissue, impair the body's immune system defenses and lead to hospital admissions and emergency room visits.[1] In addition, ground-level ozone ruptures the cells of green leaves, thereby interfering with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised.

Generally, ozone is a secondary-formation pollutant in the troposphere. That is, ozone is not emitted directly into the air, but is formed from precursor gases called oxides of nitrogen (NOx) and volatile organic compounds (VOCs) that in the presence of heat and sunlight react to form ozone.[1] Thus, ozone is generally an afternoon, summertime issue. Due to the process in which it is formed, however, high ozone levels typically do not occur in the area where the precursor gases are emitted, but may be a few to hundreds of miles away (depending on the meteorology). This means that ozone can be both a regional and a local concern.

VOCs and NOx, the ozone precursor gases, are emitted from both man-made sources (i.e. combustion, oil and gas development, etc.) and natural sources (i.e. plants, forest fires, etc.). VOC's that specifically can lead to ozone formation are generally called non-methane organic compounds (NMOCs) and do not include chlorinated compounds. In general, alkenes, aromatic hydrocarbons and carbonyls have a high ozone formation potential (higher incremental reactivity) while alkanes have a lower potential.[2] NOx primarily consists of nitric oxide (NO) and nitrogen dioxide (NO_2). NO_2, like ozone, is designated as a "criteria" pollutant that has a health-based National Ambient Air Quality Standard (NAAQS).

The NAAQS for ozone is set at a level of 0.08 parts per million for the three-year average of the annual fourth-maximum 8-hour values. However, the Clean Air Scientific Advisory Committee (CASAC) is currently recommending that the standard be reduced to a level in the range of 0.060 to 0.070 parts per million.[3] The NAAQS for NO_2 is set at 0.053 parts per million for an annual average.

Existing ozone data for the Four Corners region:
Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area (see ozone sites maps). Two other sites in the region previously monitored for ozone. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as "equivalent' or "reference" by the U.S. Environmental Protection Agency (EPA) are used. In Colorado, current monitoring is performed at Mesa Verde National Park, two Southern Ute Tribe sites and at the U.S. Forest Service (USFS) Shamrock site near Bayfield. In New Mexico, monitoring is performed at three New Mexico Environment Department (NMED) sites near the San Juan power plant, Bloomfield and Navajo Lake. A Navajo Nation site in Shiprock, NM is planned to commence operation by the end of 2007. The closest site in Arizona is located at Petrified Forest National Park and the closest site in Utah is at Canyonlands National Park. With the exception of the USFS Shamrock site, all of the data are available on EPA's Air Quality System.[4]

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

In addition, in 2003, EPA conducted a passive ozone monitoring study in the area as part of a Region 6 ozone gap study. Seven passive ozone monitoring sites were established in San Juan County in New Mexico.[5] The data showed significantly high ozone concentrations in the western and northeastern areas of San Juan County, New Mexico, in addition to the high ozone concentrations already found in the north central area of the County.[6]

Pollutant roses were developed to help provide ideas on where ozone precursor sources may come from and where high ozone concentrations may be found. Pollutant roses, like wind roses, are a simple visual way to depict pollutant concentrations as a function of wind direction for a period of time. Pollutant roses are based on the direction that the wind is blowing from. Another way of visualizing a pollutant rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The pollutant concentration is broken down into multiple ranges. The length of each arm of the pollutant rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of pollutant concentrations of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of pollutant concentration occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Pollutant roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[8]

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region (see NO_2 sites map), including two Southern Ute tribe sites and the USFS Shamrock site in Colorado, and three NMED sites. A Navajo Nation site in Shiprock, NM is scheduled to commence operation. Two other sites previously had NOx monitoring. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS (see NO_2 trends graphs). At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time. NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad (see NO trends graphs). These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic. VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.[6,7]

Data Gaps:

While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind (see ozone pollutant roses). In general, for summer afternoon periods when ozone levels are expected to be highest, winds are generally from the west to southwest. Oil and gas development increased significantly after many of the current sites were installed. This development has provided a significant increase in both VOC and NOx precursor gas sources to the region. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

Suggestions for Future Monitoring Work:

C. Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

D. Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

   (Note: In early July 2007, the Colorado legislature appropriated funding for passive ozone monitoring in Colorado. As a result, a short-term study was performed in three areas of Colorado at 50 locations. These areas included the north Front Range, central western and southwestern/Four Corners. For the southwestern area, 12 passive ozone sampling sites were operated from early August to early September 2007. While not a definitive study, funding is expected to be available in future years to perform more refined passive ozone monitoring.)

E. Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

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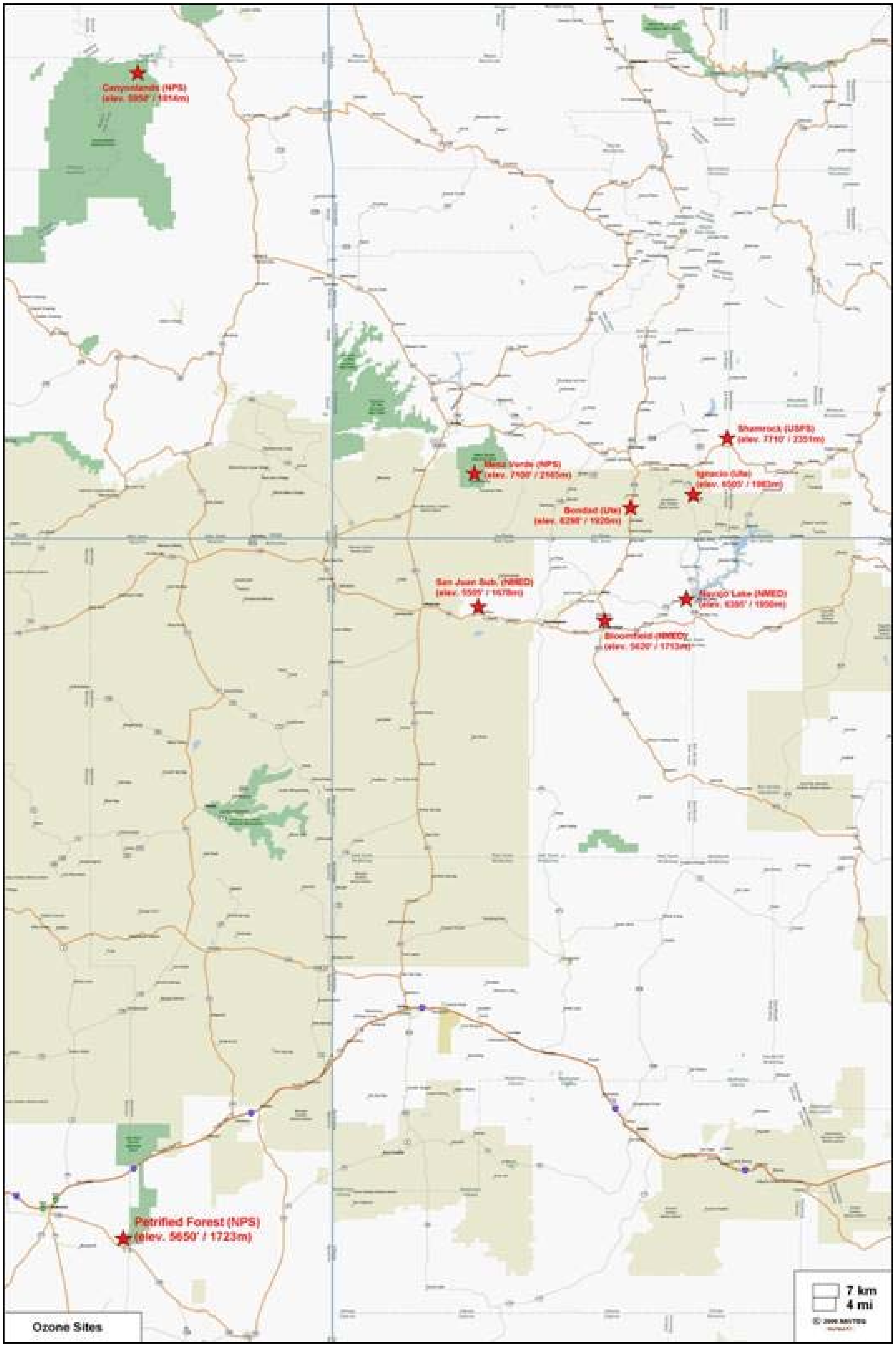
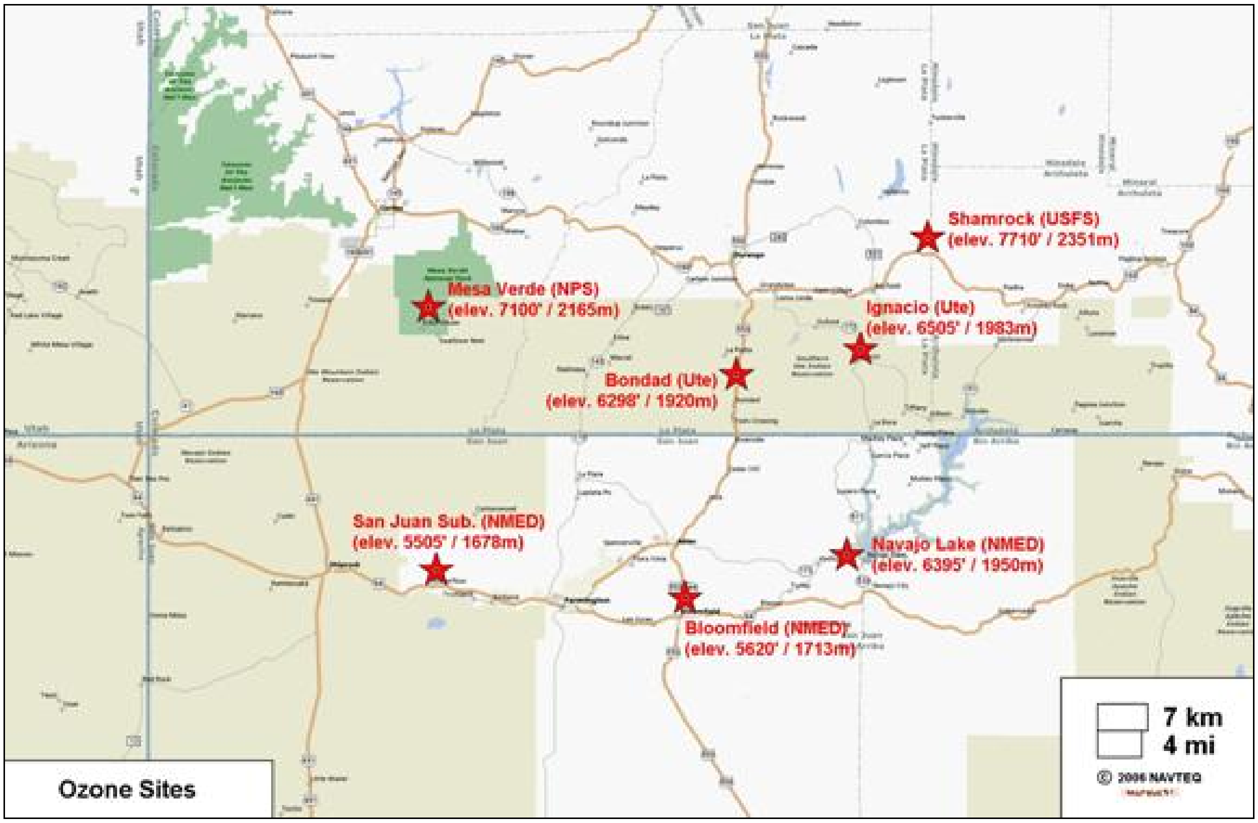
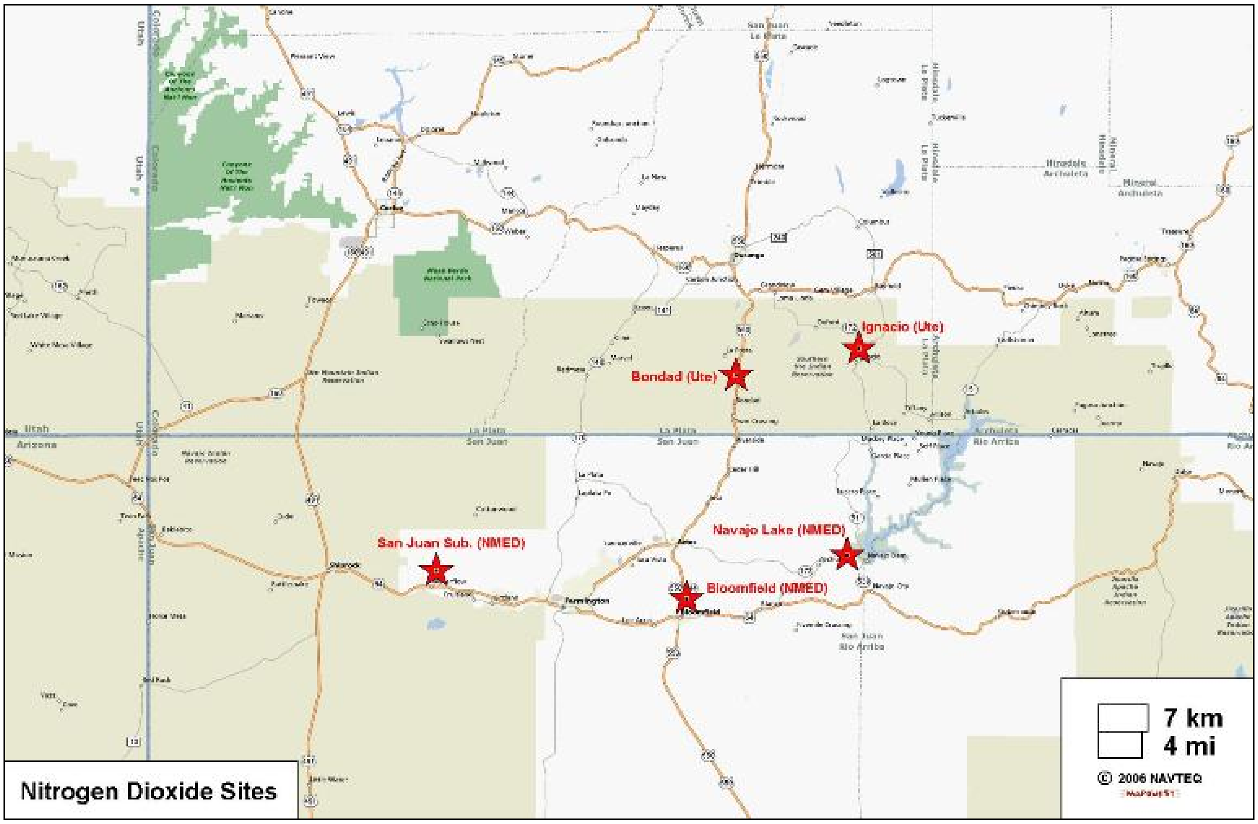
Four Corners --- Continuous Ozone Sites in 2006



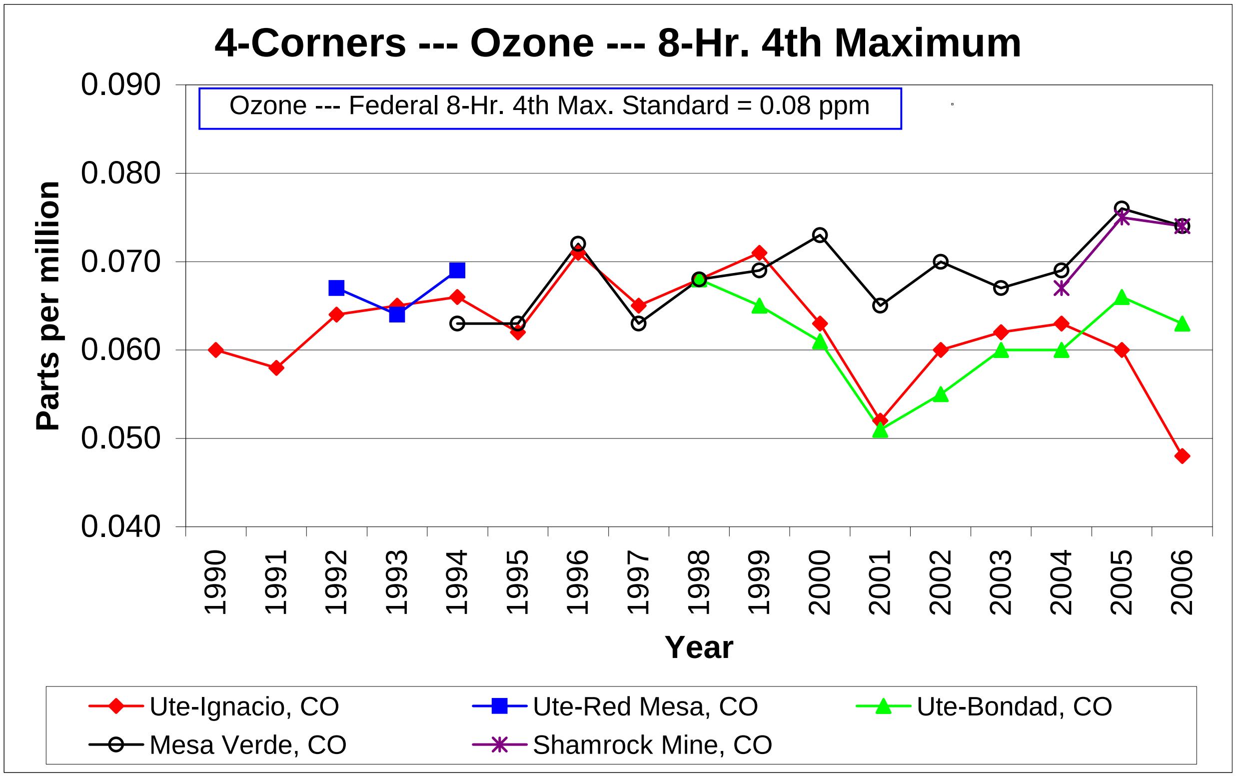
Close-in Four Corners --- Continuous Ozone Sites in 2006

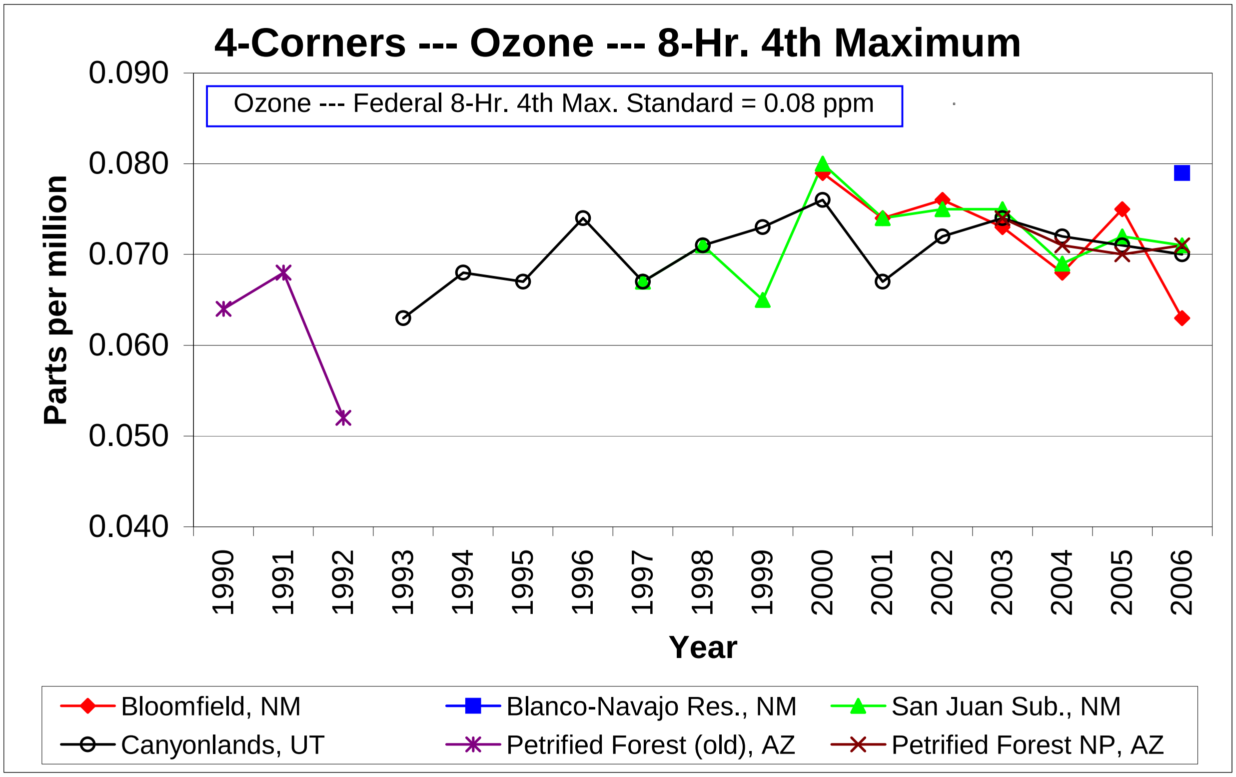


Four Corners --- Continuous Nitrogen Dioxide Sites in 2006

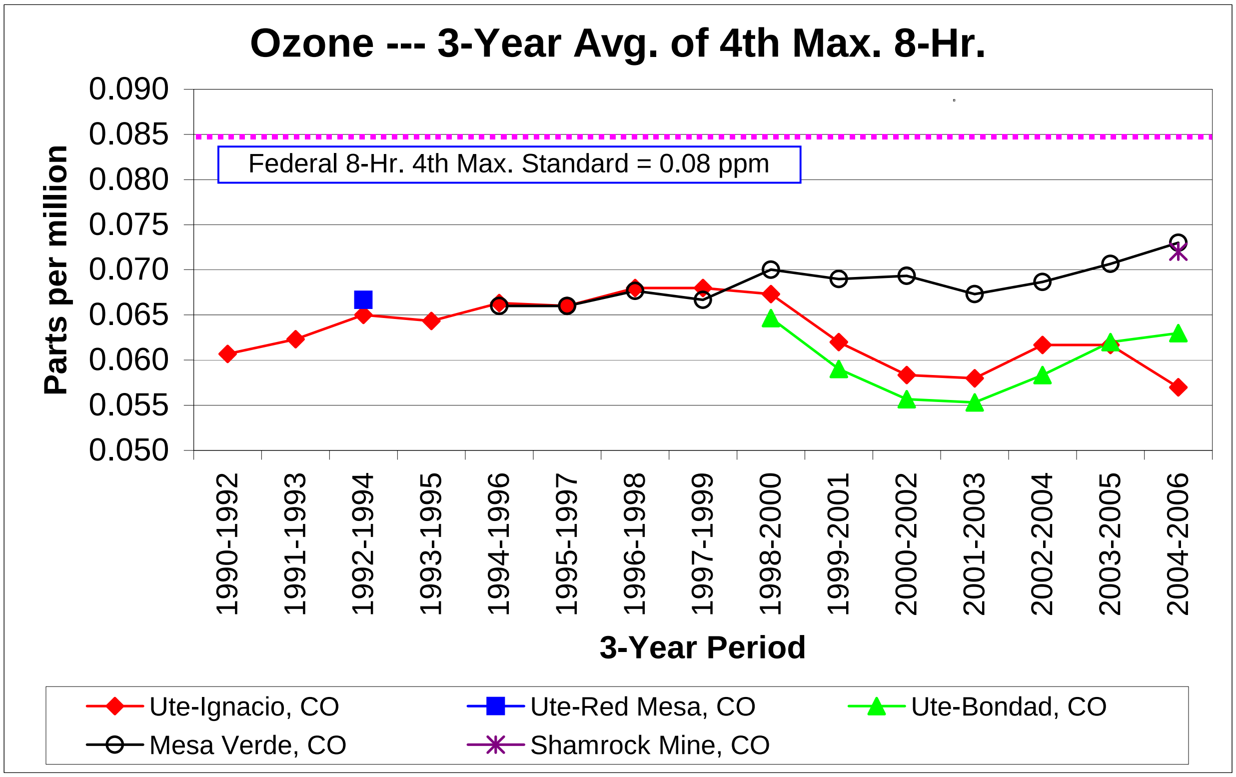


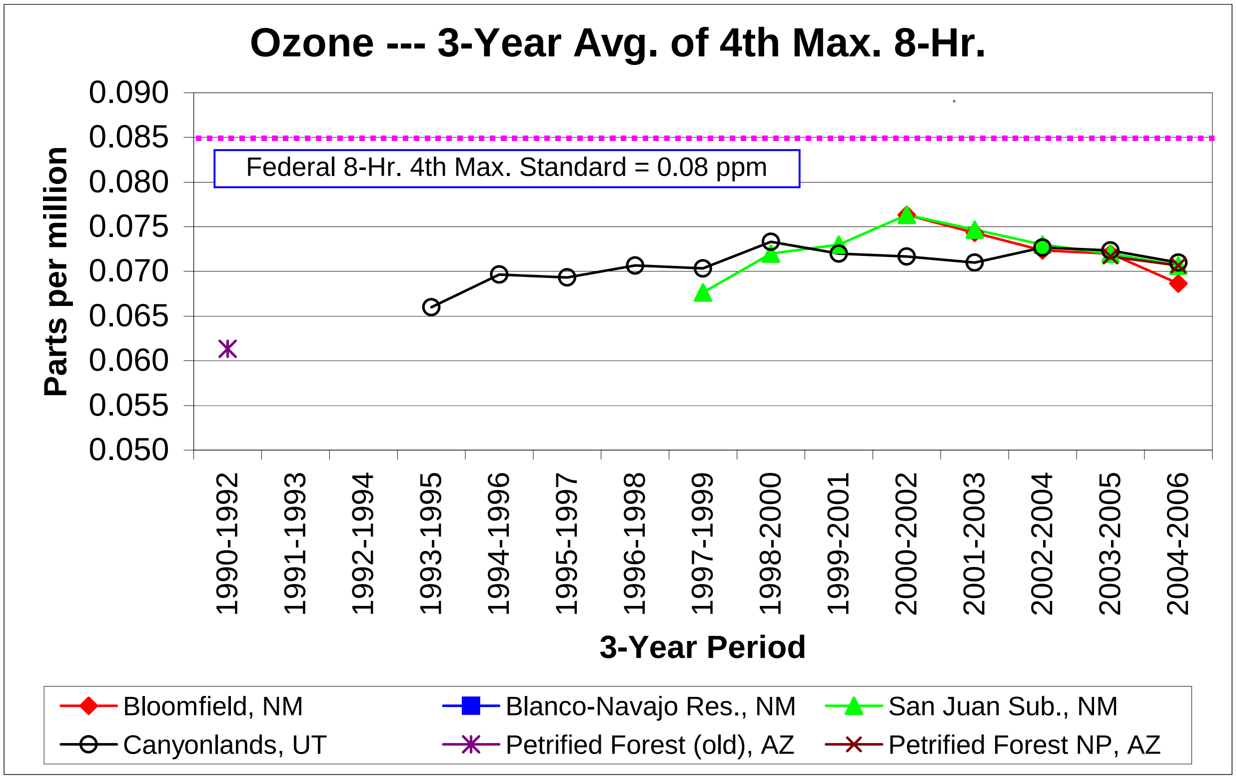
Four Corners --- Ozone Trends (4th Maximum 8-Hour)



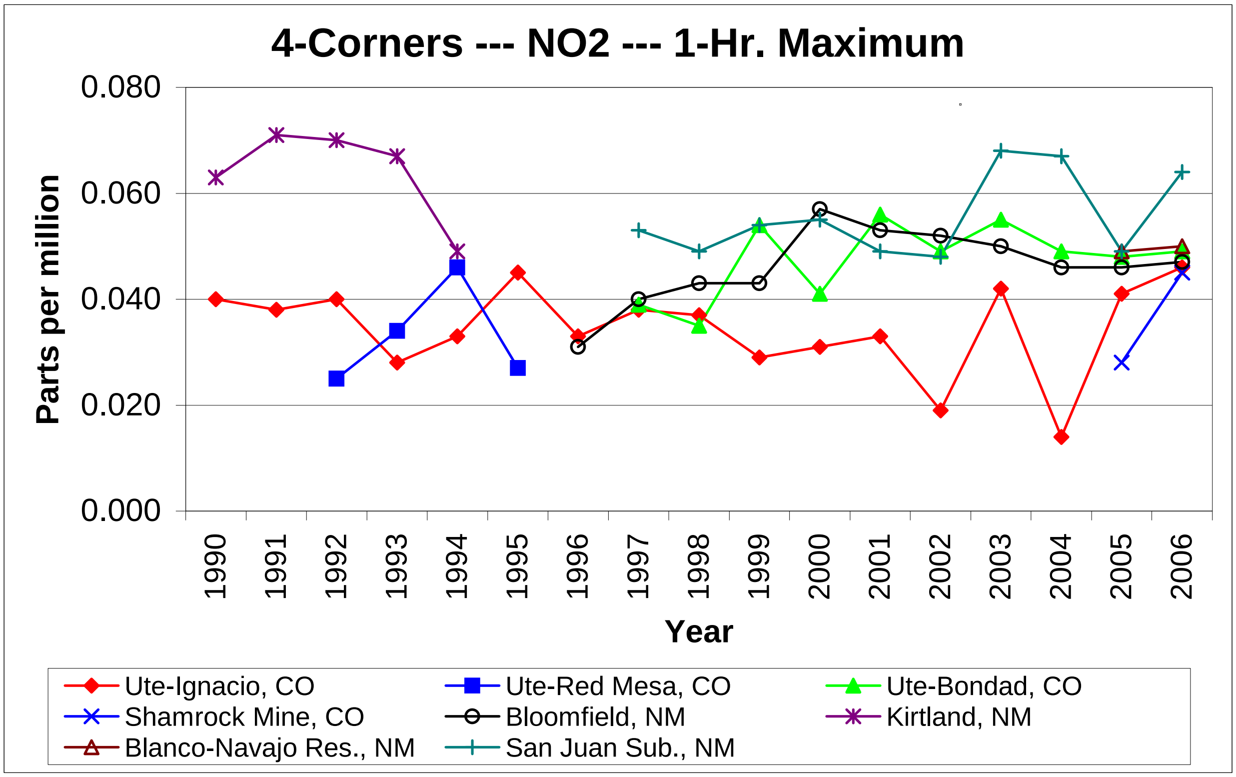


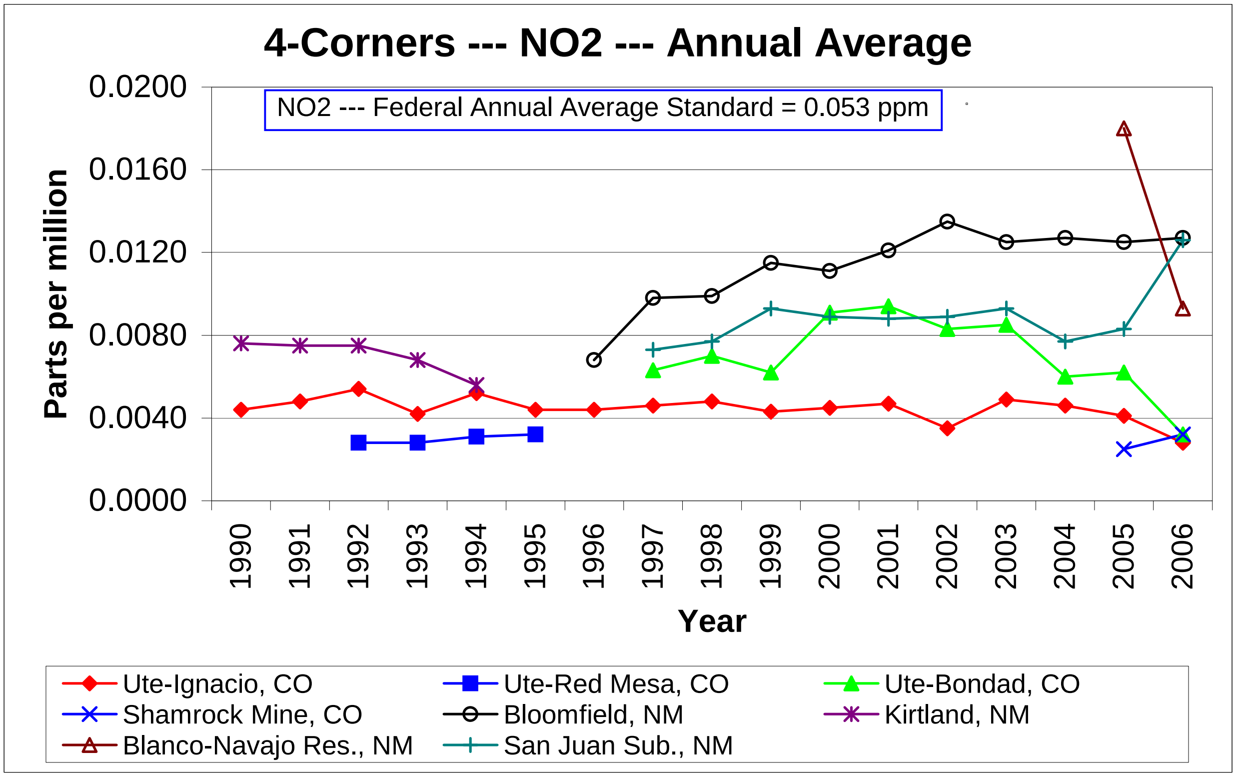
Four Corners --- Ozone Standard (3-Year Avg. of 4th Max. 8-Hour)



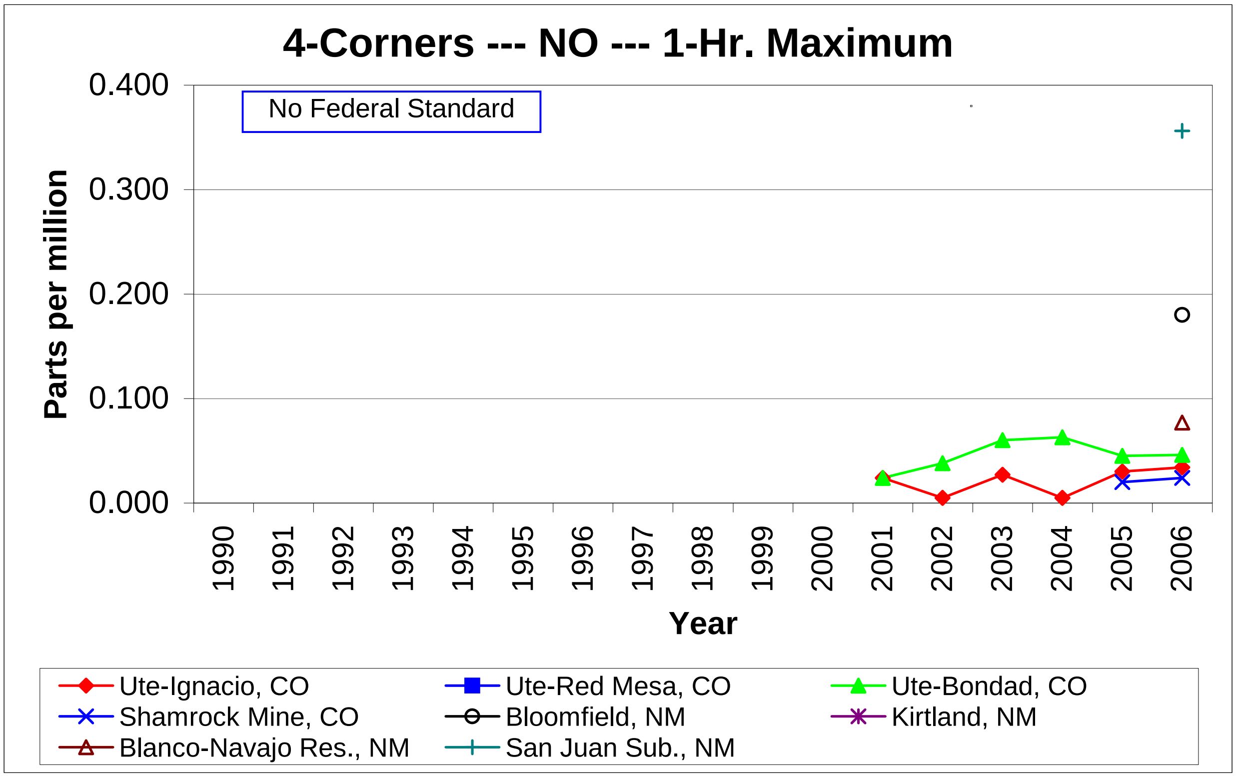


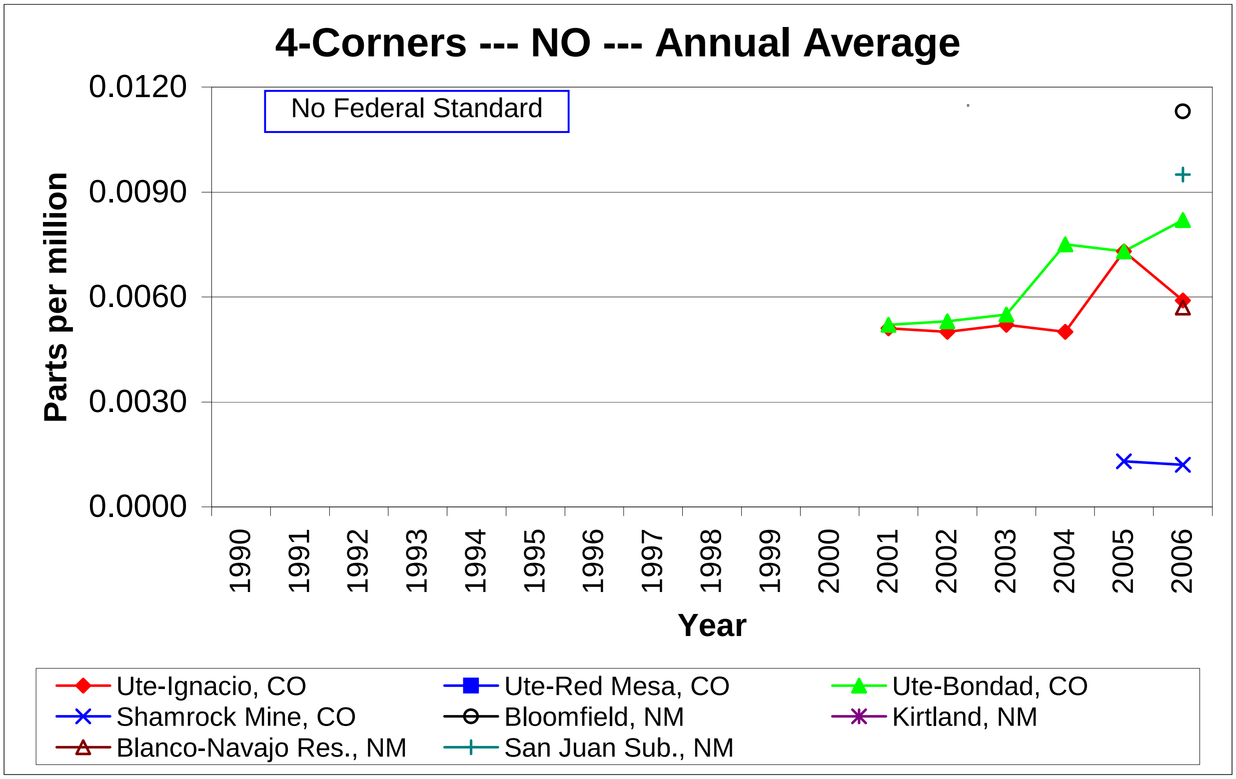
Four Corners --- Nitrogen Dioxide Trends



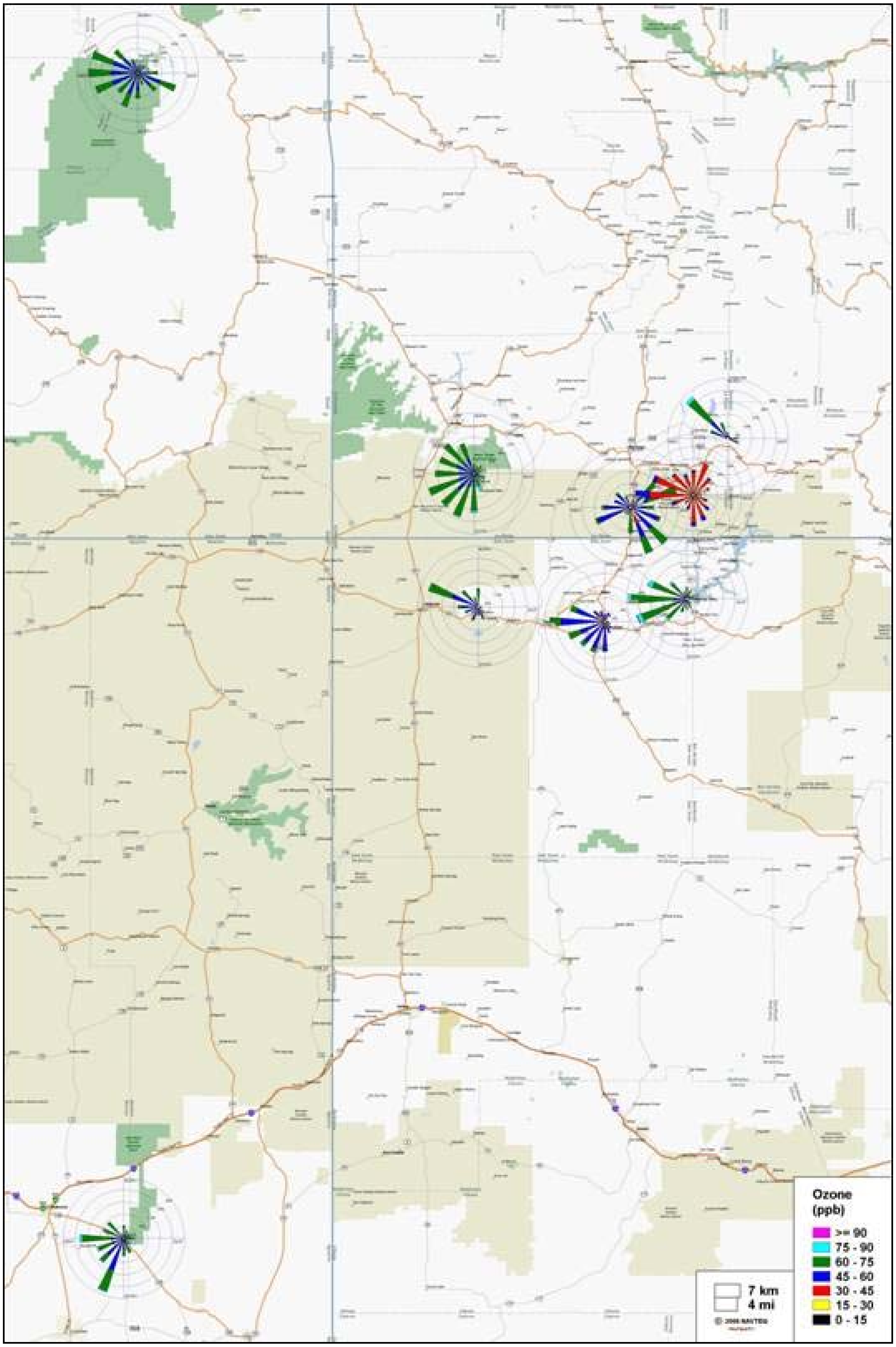


Four Corners --- Nitric Oxide Trends

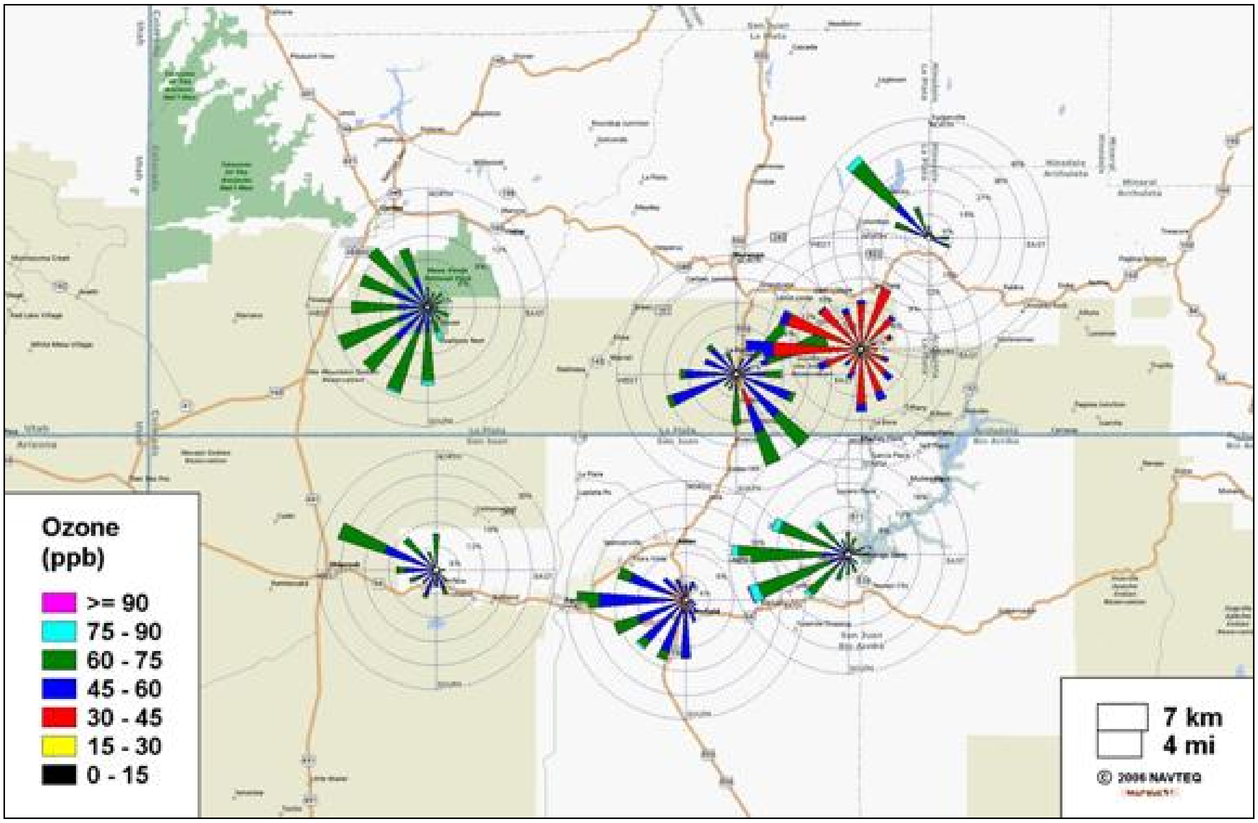




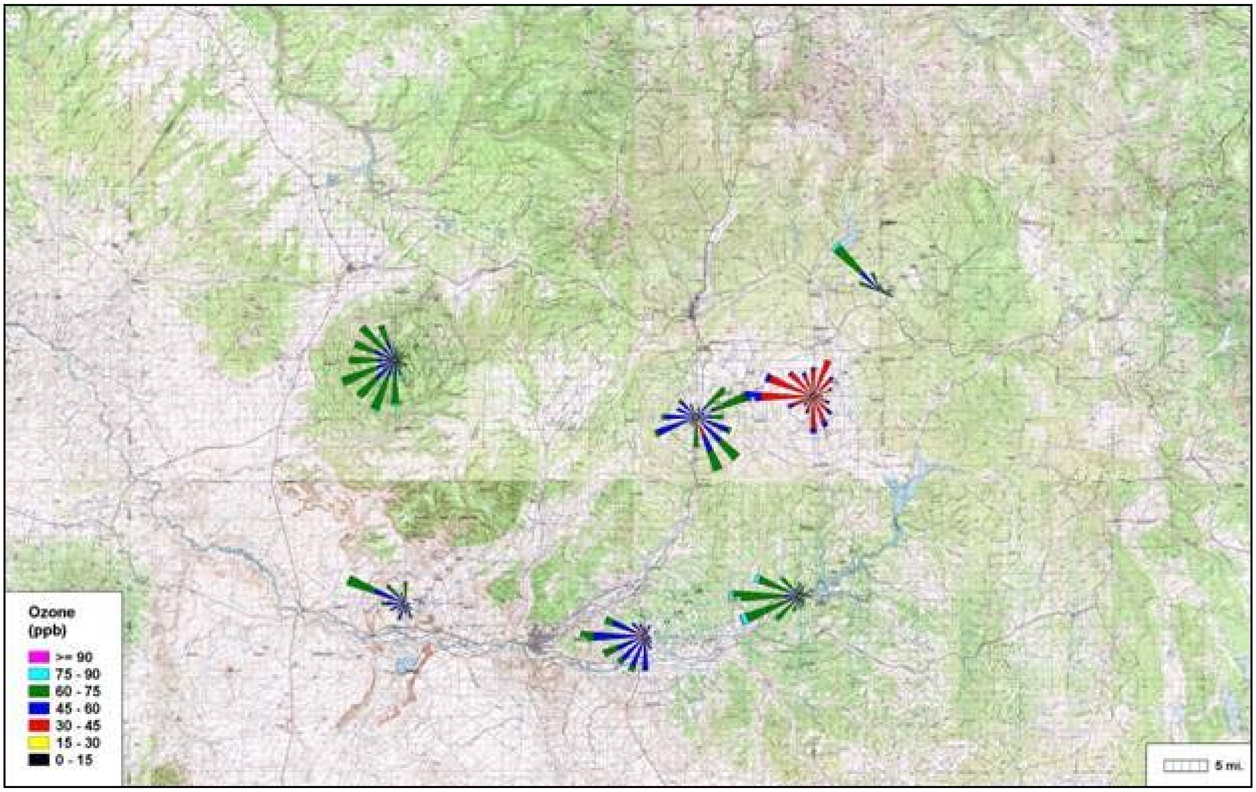
Overall Four Corners --- Summer Afternoon Ozone Pollution Roses (2006)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006) (Political boundary map)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006) (Topographic map)



Carbon Monoxide, Particulates and Other Common Pollutants

Background:

Rationale and Benefits**:**
Carbon monoxide, or CO, is a colorless, odorless gas that is formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 56 percent of all CO emissions nationwide. Other non-road engines and vehicles (such as construction equipment and boats) contribute about 22 percent of all CO emissions nationwide. Higher levels of CO generally occur in areas with heavy traffic congestion. In cities, 85 to 95 percent of all CO emissions may come from motor vehicle exhaust. Other sources of CO emissions include industrial processes (such as metals processing and chemical manufacturing), residential wood burning, and natural sources such as forest fires. Woodstoves, gas stoves, cigarette smoke, and unvented gas and kerosene space heaters are sources of CO indoors. The highest levels of CO in the outside air typically occur during the colder months of the year when inversion conditions are more frequent.[1]

Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. This results in cardiovascular and/or central nervous system effects, such as chest pains, vision problems and reduced ability to work or exercise.[1] The health-based National Ambient Air Quality Standard (NAAQS) for carbon monoxide is set at a level of 35 parts per million for a one-hour average and 9 parts per million for an eight-hour average.[2]

Particulates are broken into two categories for NAAQS: PM_{10}, which is particulate matter that is 10-microns in diameter and smaller, and $PM_{2.5}$, which is particulate matter 2.5 microns in diameter and smaller. Thus, $PM_{2.5}$ is a subset of PM_{10}. Particulates are an inhalable mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to be seen with the naked eye. Others are so small, they can only be detected using an electron microscope. These particles come in many sizes and shapes and can be made up of hundreds of different chemicals. Some particles, known as *primary particles* are emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks or fires. Others form in complicated reactions in the atmosphere of chemicals such as sulfur dioxides and nitrogen oxides that are emitted from power plants, industries and automobiles. These particles, known as *secondary particles,* make up most of the fine particle pollution in the country.[3]

Particle pollution, especially fine particles, contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including increased respiratory symptoms (such as irritation of the airways, coughing, or difficulty breathing), decreased lung function, aggravated asthma, development of chronic bronchitis, irregular heartbeat, nonfatal heart attacks and premature death in people with heart or lung disease.[3] The health-based NAAQS for PM10 is set at a level of 150 micrograms per cubic meter for a 24-hour average. For PM2.5, the health-based NAAQS are set at levels of 35 micrograms per cubic meter for a 24-hour average and 15 micrograms per cubic meter for an annual average.[2]

Other common pollutants in the ambient air that are not covered in other option papers may include lead, carbon dioxide, organic compounds/hazardous air pollutants (HAPs), pesticides, and others. Of these, only lead has a health-based NAAQS, which is 1.5 micrograms per cubic meter for a calendar quarter average.[2]

Lead is primarily emitted from metals processing or waste incinerator sources. Historically, leaded automobile fuels were the primary source.[4] Lead is typically associated with neurological impairment. Carbon dioxide is emitted from a variety of natural and human-related sources. With implications as a greenhouse gas rather than health concerns, the largest man-made source of carbon dioxide, by far, is fossil fuel combustion.[5] Organic compounds can be both toxic and non-toxic in nature. Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. These compounds can come from a variety of sources, though primarily from industrial or mobile (i.e. motor vehicle) source. Thus, they are typically associated with urban areas.[6] The U.S. Environmental Protection Agency currently lists 188 HAPs for which it would like to reduce atmospheric releases/emissions. While no ambient standards currently exist for these pollutants, workplace standards do exist for some of them. Pesticides are substances or mixture of substances intended for preventing, destroying, repelling, or mitigating any pest.[7] While all regulated pesticides have been tested for health impacts to humans, exposures can and do occur from improper use.

Existing data for the Four Corners region:
Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. (See the CO site locations map.) All of the data are available on EPA's Air Quality System.[8] Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS (see the CO trends and standards graph). Carbon monoxide levels nationwide are now very low due in large part to improved vehicle technology and emissions controls.

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. (See the PM_{10} site locations map.) Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS (see the PM_{10} trends graphs). As a result, some of the monitors were shut down at the end of 2006.

$PM_{2.5}$ in the ambient air has also been monitored at a number of locations in Four Corners region. (See the $PM_{2.5}$ site locations map.) Most of the monitoring has been performed using filter-based "low-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient $PM_{2.5}$ levels in the Four Corners region are well below the levels of the current NAAQS for both the 24-hour average and annual averages (see the $PM_{2.5}$ trends graphs). $PM_{2.5}$ has also been monitored as part of the IMPROVE network. These data are not on EPA's Air Quality System but may be obtained on the IMPROVE website.[9]

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides. While carbon dioxide is a greenhouse gas and is emitted from combustion sources, it is not considered to be toxic at typical ambient concentrations. Thus, there has been no specific reason for monitoring and no standards exist. No standards currently exist for organic compounds, including HAPs (such as volatile and semi-volatile organic compounds) and pesticides. Much of the monitoring for these compounds has been performed in urban areas where concentrations are expected to be higher, particularly for the HAPs, and more people are at risk for exposure. Several pilot and trends studies are currently underway across the nation, but the cost is very high for routine monitoring. Volatile organic compound baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites by the U.S. Environmental Protection Agency (EPA) Region 6. This study was primarily for ozone precursor organic compounds rather than for overall HAPs.[10,11]

Data Gaps:
Due to the very low levels of carbon monoxide, PM_{10} and $PM_{2.5}$ at existing or former air monitoring sites and at other surrounding areas, there is not expected to be any areas of the Four Corners region that need additional monitoring of these threeo pollutants to demonstrate NAAQS compliance. While there has been no monitoring for lead in the Four Corners region, the low levels that are seen nationwide and the lack of sources in the area indicate that no monitoring is likely to be needed. There is no NAAQS for carbon dioxide, so on a health basis, no monitoring is needed.

With organic compounds/HAPs and pesticides, there is little data for the area that exists. However, based on monitoring that is being performed nationwide in EPA's National Air Toxics Trends Study, there are not expected be concentrations that are much different from other areas. Due to the expense of monitoring, other areas would probably suffice as a surrogate. In addition, there are no significant major sources of HAPs in the region to warrant ambient monitoring. As part of "Ozone and Precursor Gases" suggestions, volatile organic compound/non-methane organic compound monitoring is being recommended. Pesticides may be a health issue for the agricultural population. This would lead to specific investigations rather than ambient monitoring sites.

Suggestions for Future Monitoring Work:

No suggestions for additional monitoring of carbon monoxide, PM_{10}, $PM_{2.5}$ and other common pollutants are currently being proposed.

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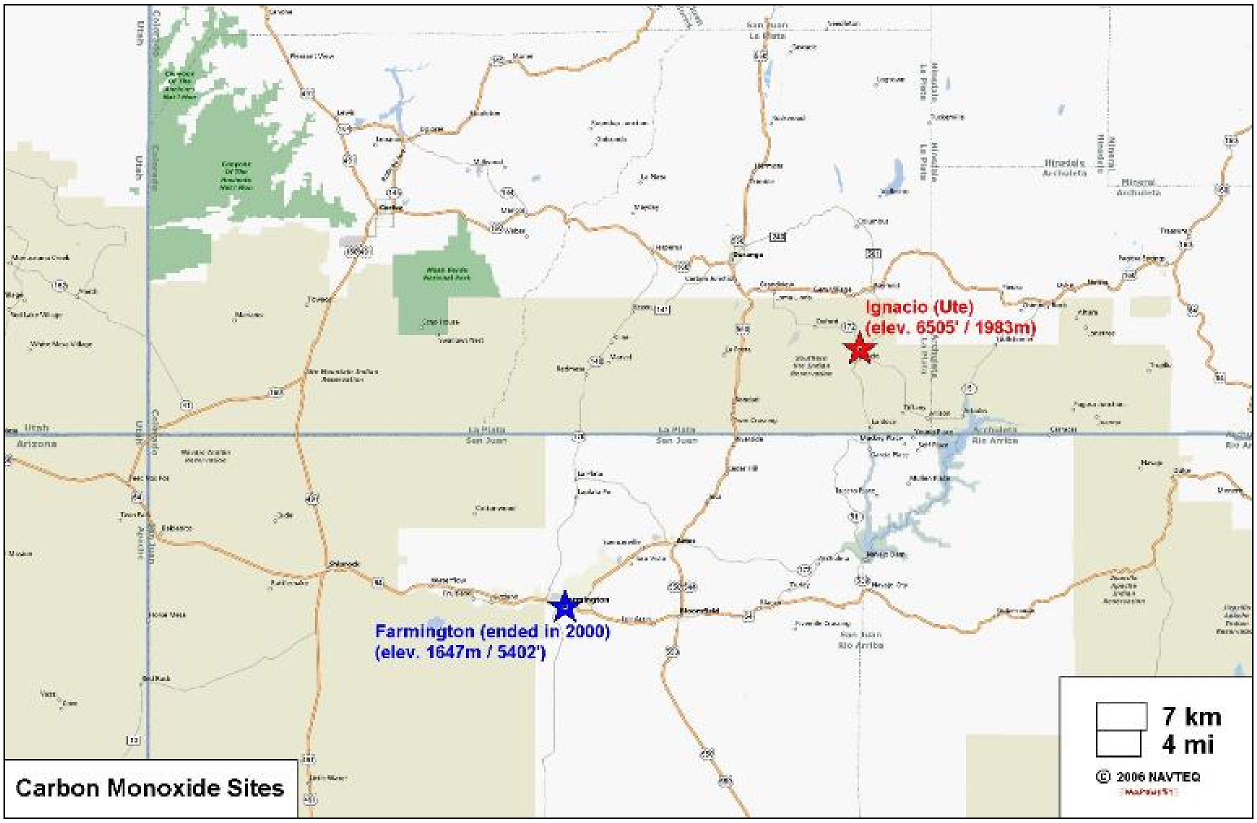
Four Corners --- Continuous Carbon Monoxide Sites in 2006



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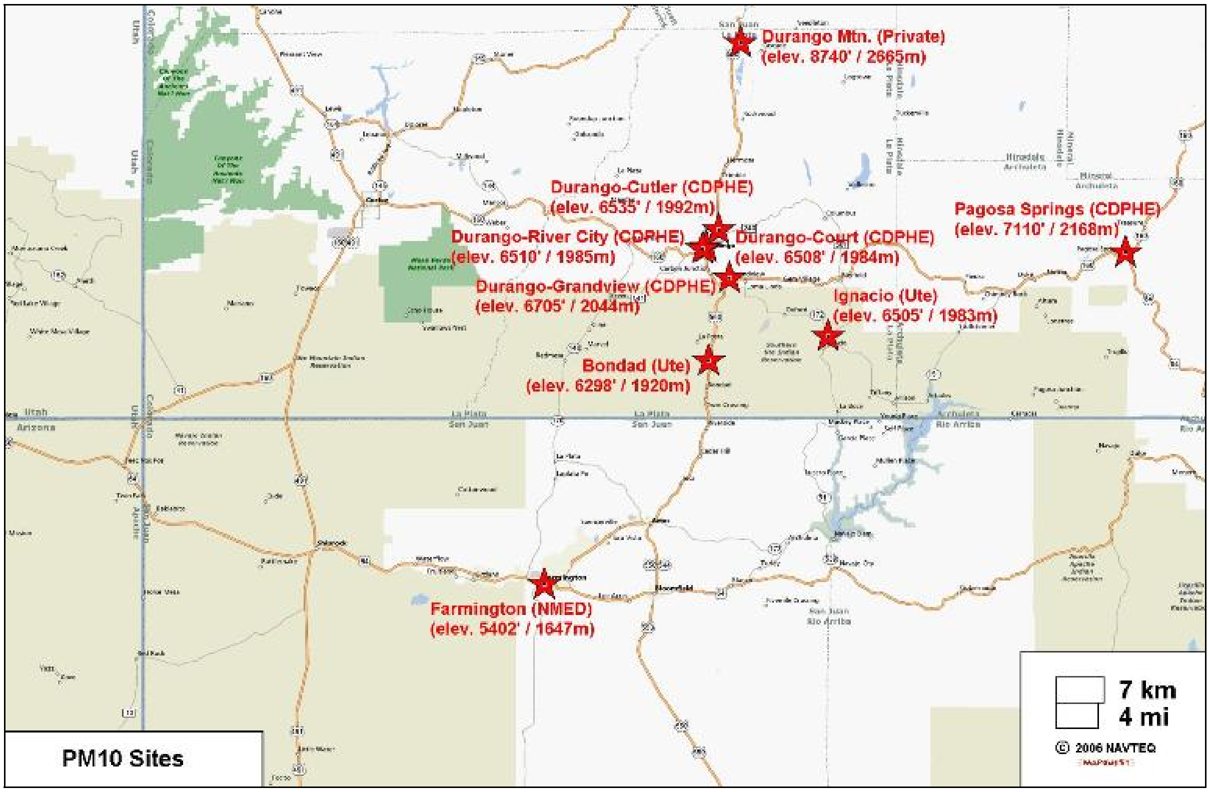
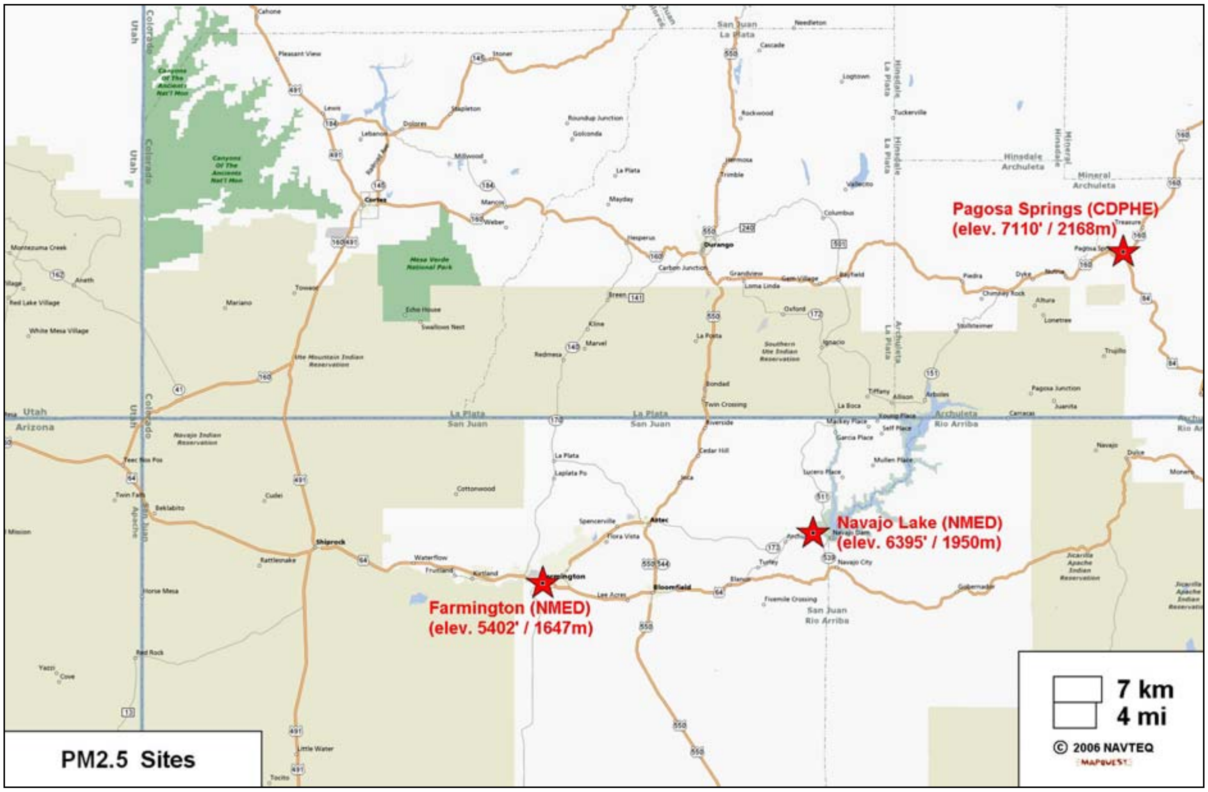
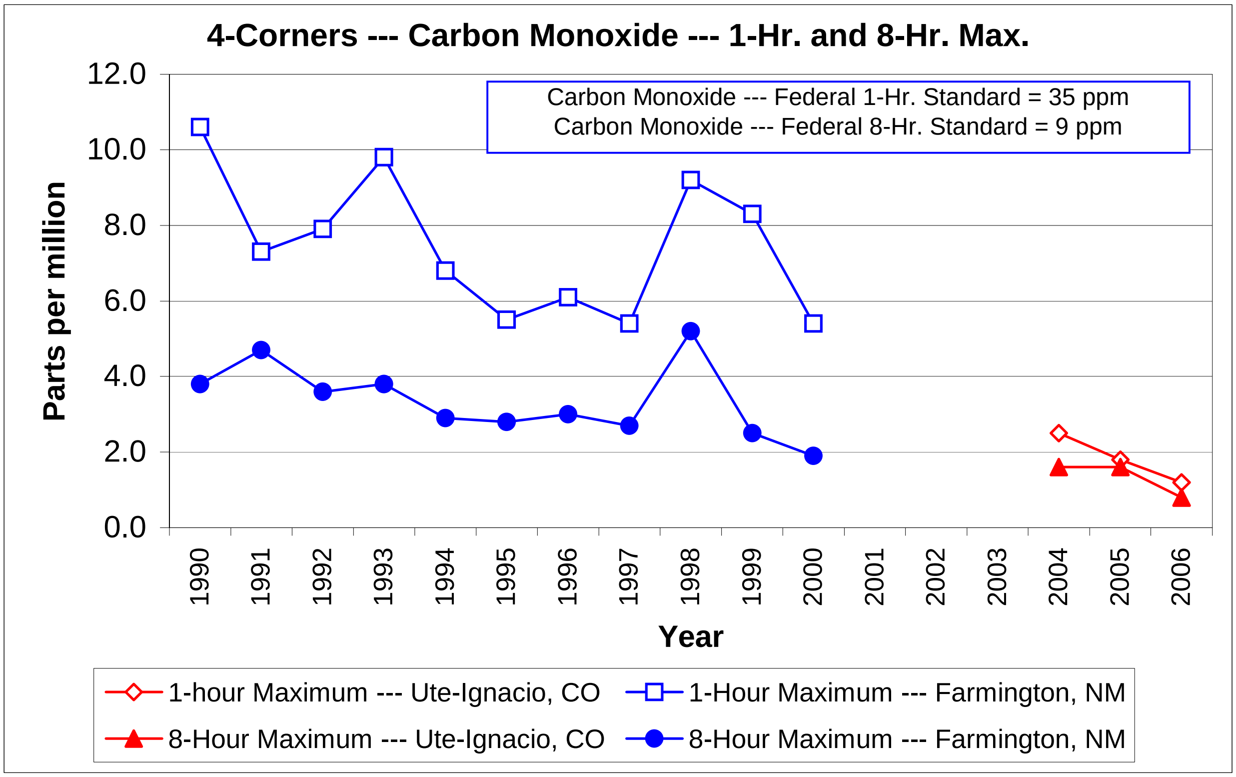
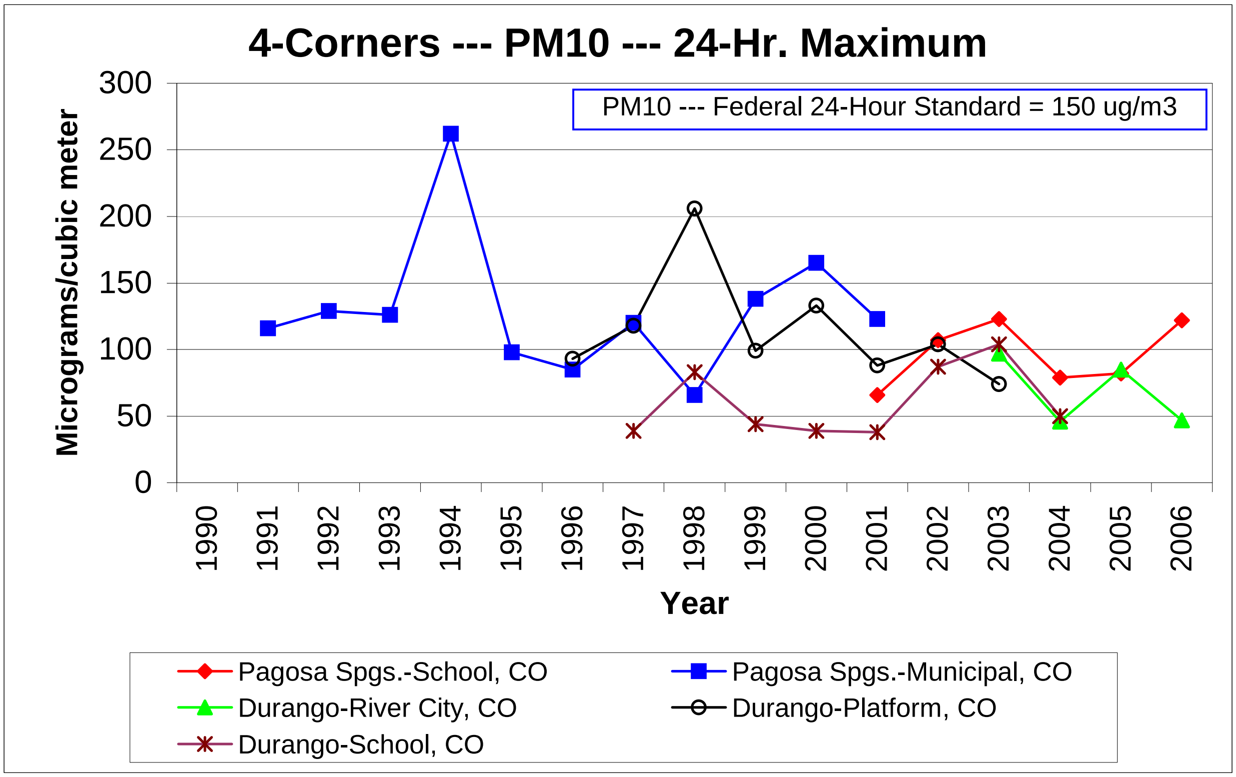


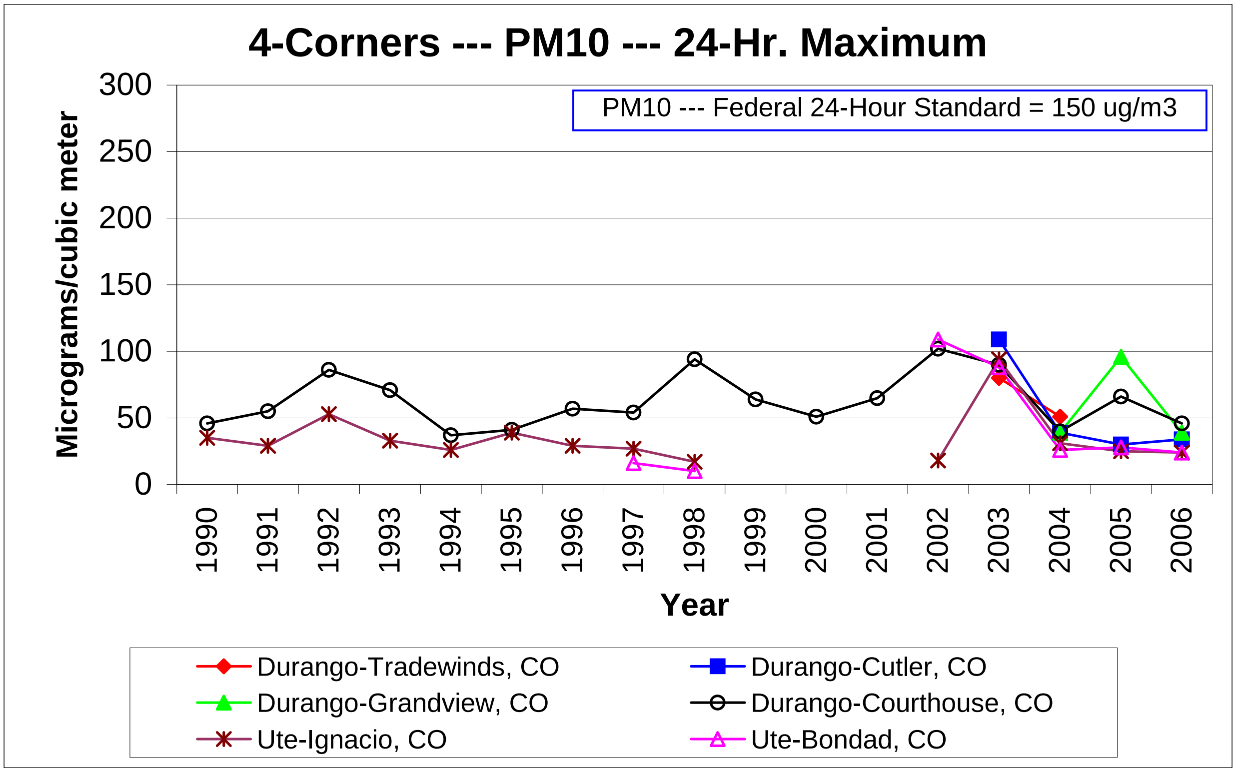


Four Corners --- Carbon Monoxide Trends (1-Hour and 8-Hour)

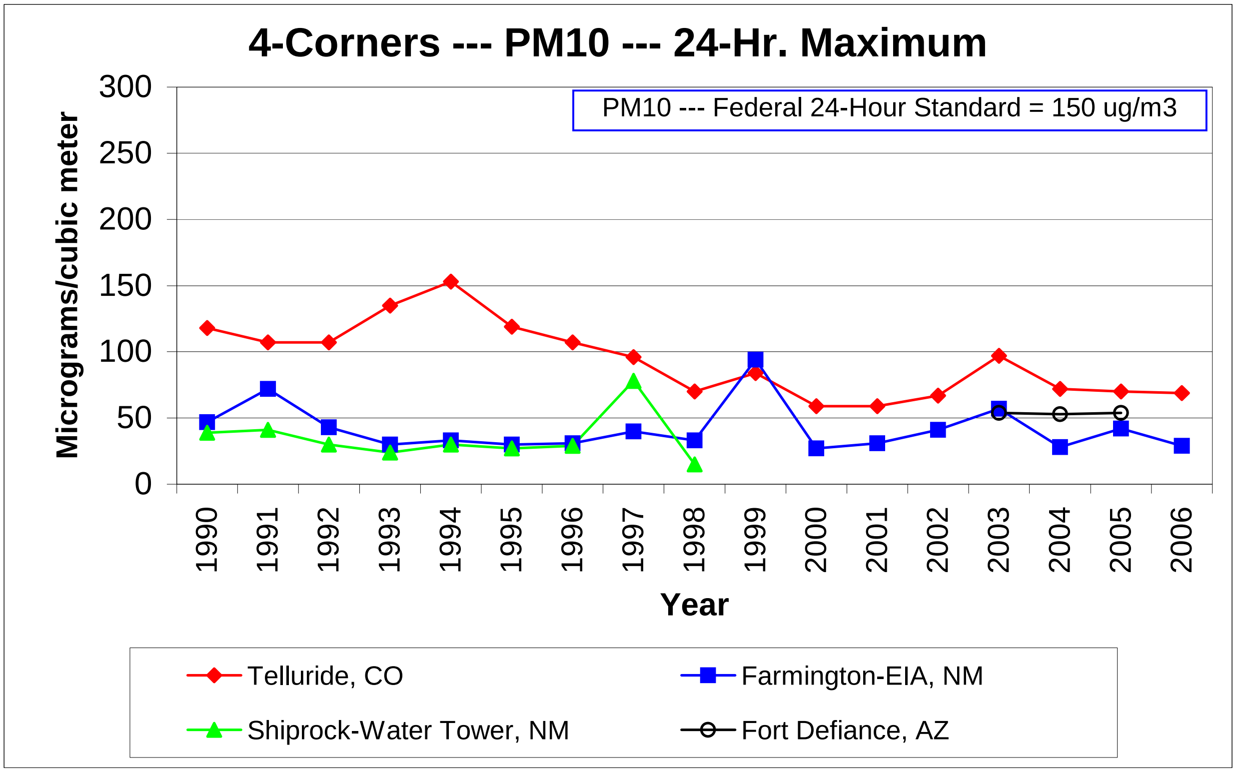


Four Corners --- PM_{10} Trends (24-Hour Maximum)

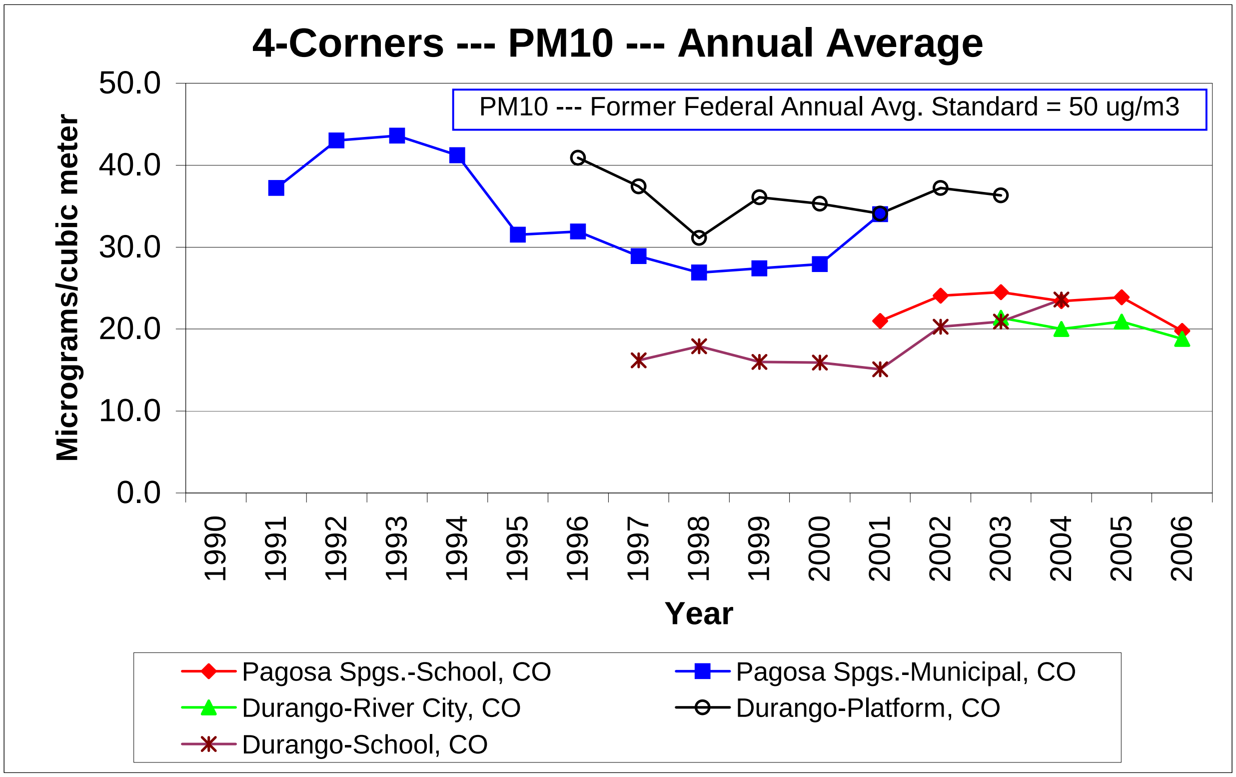


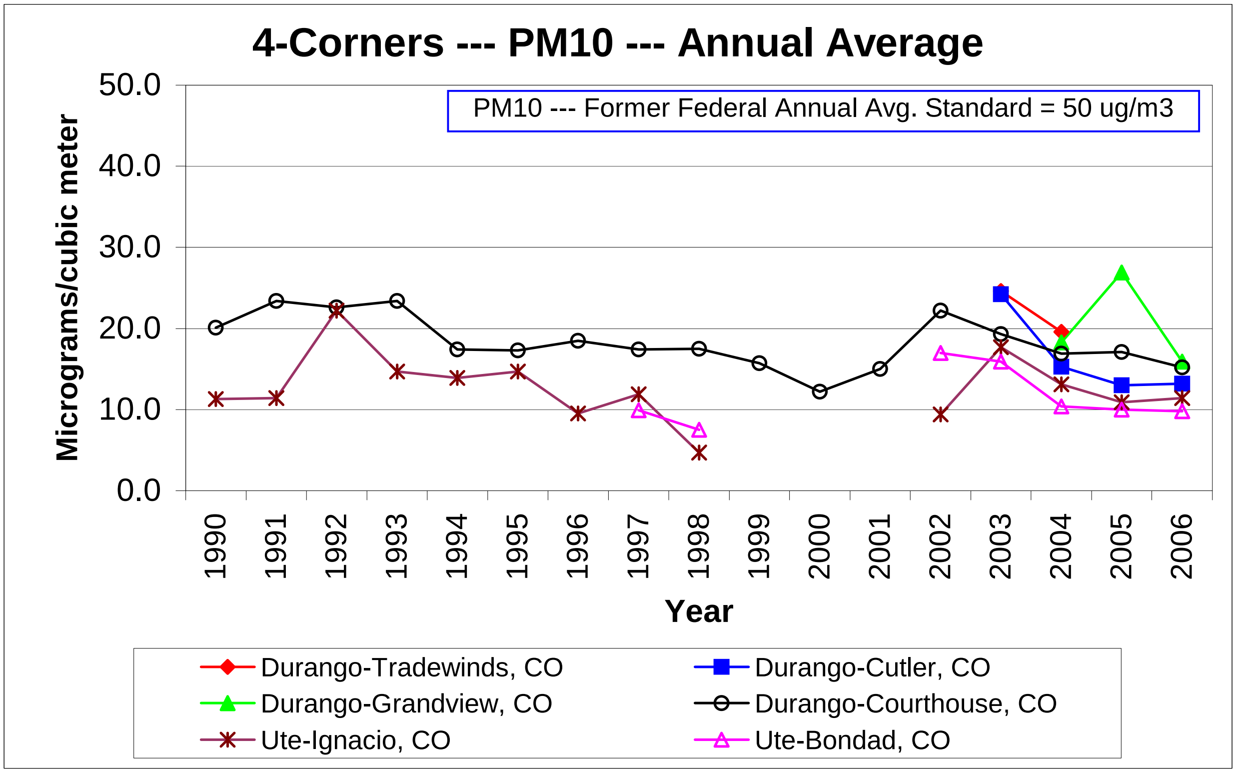


Four Corners --- PM_{10} Trends (24-Hour Maximum) – cont.

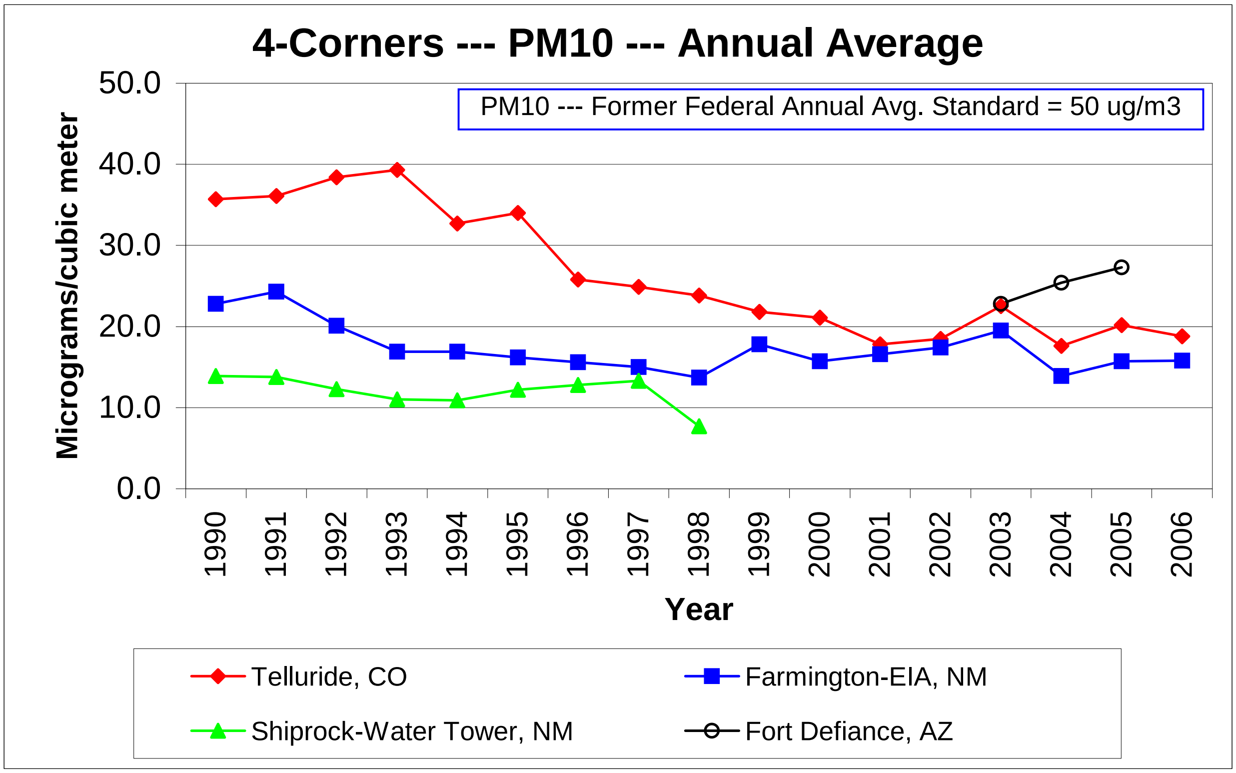


Four Corners --- PM_{10} Trends (Annual average)

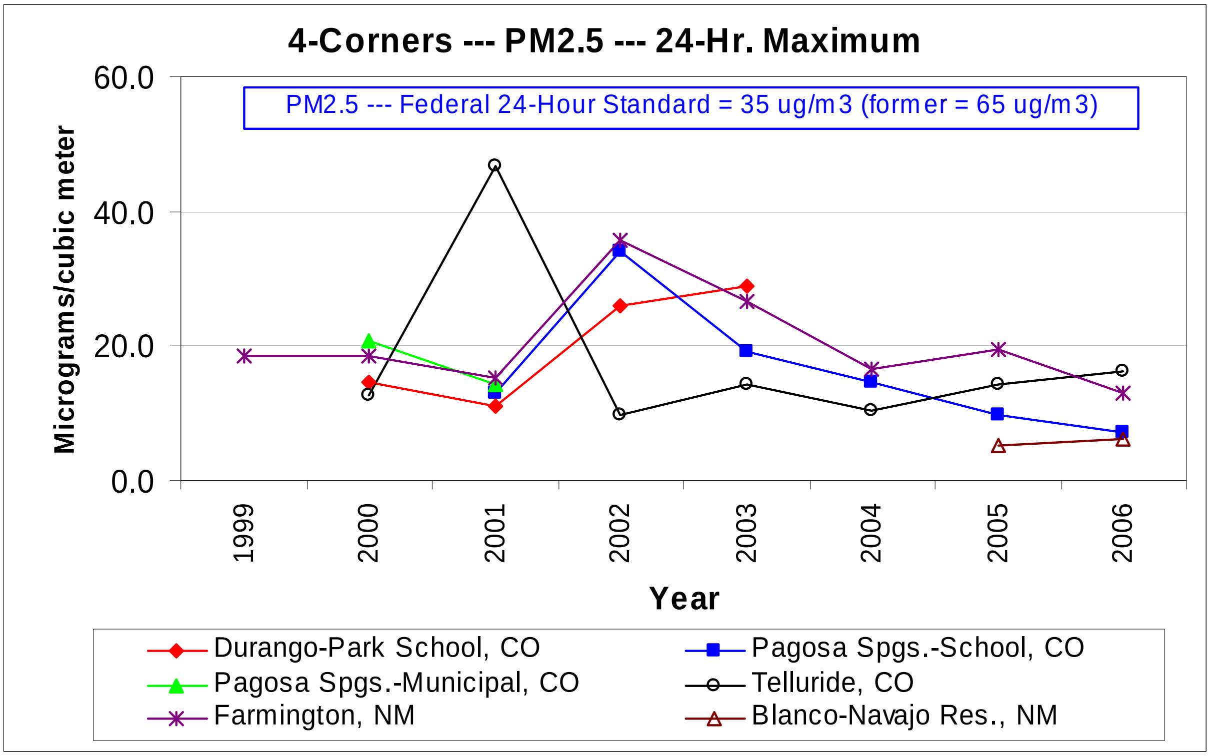




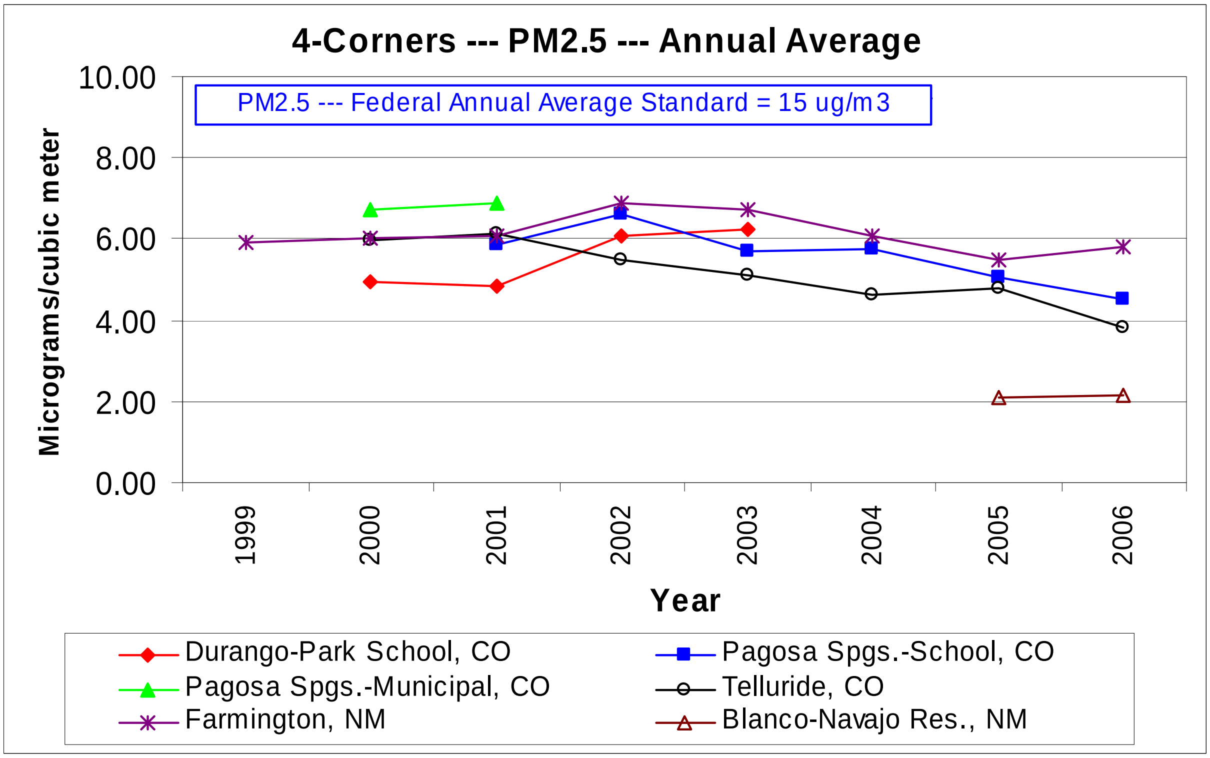
Four Corners --- PM_{10} Trends (Annual average) – cont.



Four Corners --- $PM_{2.5}$ Trends (24-Hour Maximum)



Four Corners --- $PM_{2.5}$ Trends (Annual average)



Uranium, Radionuclides and Radon

Background:

Rationale and Benefits:
Uranium is a naturally-occurring element found at low levels in virtually all rock, soil, and water. In a raw form, it is a silvery white, weakly radioactive metal. It has the highest atomic weight of the naturally occurring elements. Significant concentrations of uranium occur in some substances such as phosphate rock deposits, and minerals such as uraninite in uranium-rich ores. The largest single source of uranium ore in the United States is the Colorado Plateau region, located in Colorado, Utah, New Mexico, and Arizona.[1] Radionuclides are unstable nuclides of elements and may be natural or man-made in origin. Radon is a naturally occurring radioactive gas that is a decay product.

Uranium in soil and rocks is distributed throughout the environment by wind, rain and geologic processes. Rocks weather and break down to form soil, and soil can be washed by water and blown by wind, moving uranium into streams and lakes, and ultimately settling out and reforming as rock. Uranium can also be removed and concentrated by people through mining and refining. These mining and refining processes produce wastes such as mill tailings which may be introduced back into the environment by wind and water if they are not properly controlled. Manufacturing of nuclear fuel, and other human activities also release uranium to the environment.[2]

It is important to keep in mind that uranium is naturally present in the environment (both in air and in water) and is in your normal diet, so there will always be some level of uranium in all parts of your body.[3] The average daily intake of uranium from food ranges from 0.07 to 1.1 micrograms per day. About 99 percent of the uranium ingested in food or water will leave a person's body in the feces, and the remainder will enter the blood. Most of this absorbed uranium will be removed by the kidneys and excreted in the urine within a few days. A small amount of the uranium in the bloodstream will deposit in a person's bones, where it will remain for years.[2]

The greatest health risk from large intakes of uranium is toxic damage to the kidneys, because, in addition to being weakly radioactive, uranium is a toxic metal. Uranium exposure also increases the risk of getting cancer due to its radioactivity. Since uranium tends to concentrate in specific locations in the body, risk of cancer of the bone, liver cancer, and blood diseases (such as leukemia) are increased. Inhaled uranium increases the risk of lung cancer.[2] In addition, uranium can decay into other radioactive substances, such as radium, which can cause cancer if exposed to enough of them for a long enough period of time.[3]

The Occupational Safety and Health Administration has set occupational exposure limits for uranium in breathing air over an 8-hour workday, 40-hour workweek. The limits are 0.05 milligrams per cubic meter (0.05 mg/m³) for soluble uranium dust and 0.25 mg/m³ for insoluble uranium dust.[3] Uranium in drinking water is covered under the Safe Water Drinking Act, which establishes maximum contaminant levels, or MCLs, for radionuclides and other contaminants in drinking water. The uranium limit is 30 µg/l (micrograms per liter) in drinking water. The Clean Air Act limits emissions of uranium into the air where the maximum dose to an individual from uranium in the air is 10 millirem.[4] There are no Federal ambient air standards for uranium.

The isotope ^{235}U is useful as a fuel in power plants and weapons. To make fuel, natural uranium is separated into two portions. The fuel portion has more ^{235}U than normal and is called enriched uranium. The leftover portion with less ^{235}U than normal is called depleted uranium, or DU. Natural, depleted, and enriched uranium are chemically identical. Depleted uranium is the least radioactive and enriched uranium the most.[3]

Due to concerns on foreign oil dependence and global warming, renewed interest is being shown in nuclear power generation. The Colorado Plateau, as noted above, has a high concentration of uranium ore. As a result, there is increasing interest in the area for both uranium mining and milling. Of particular concern are milling operations where the mill tailings are rich in the chemicals and radioactive materials that were not removed. In the milling process, the ore is crushed and sent through an extraction processes to concentrate the uranium into uranium-oxygen compounds called yellowcake. The remainder of the crushed rock, in a processing fluid slurry, is placed in a tailings pile.[5] The most important radioactive component of uranium mill tailings is radium, which decays to produce radon.

The radium in these tailings will not decay entirely for thousands of years. Other potentially hazardous substances in the tailings are selenium, molybdenum, uranium, and thorium.[4]

In the Four Corners area, there is currently one operating uranium mill, located near Blanding Utah. A mill has also been proposed near Naturita in western Colorado. Mining operations have also been proposed in San Miguel County in Colorado. This has led to concerns over potentially increased exposures to radionuclides, radon and contaminated dusts from both mills/tailings piles and mines. Immediate concerns would be to the general public in the immediate vicinity of these facilities/operations. However, there are also concerns over longer range air transport of radionuclides, radon and contaminated dusts for the region, especially as the number of these facilities/operations may increase significantly.

Existing uranium data for the Four Corners region:
Currently, little current ambient air monitoring data exists for uranium in the Four Corners region. Neither the States of Colorado nor Utah are currently performing any monitoring around uranium mining or milling operations. From historical mining and milling, total suspended particulate and radionuclide data exist from private monitoring.

As part of National Emissions Standards for Hazardous Air Pollutant regulations (through the U.S. Environmental Protection Agency), monitoring is required to be performed to assess and limit emissions of radon and radionuclides from mines, mills and tailings.[6] U.S. Nuclear Regulatory Commission guidelines call for both onsite and offsite particulate monitoring for radionuclides, radon monitoring and meteorological monitoring at uranium mills. This monitoring is required both prior to operation and during operation.

Data Gaps:
While little ambient air monitoring data exists for uranium mine and milling operations/facilities, emissions monitoring and modeling is required under National Emissions Standards for Hazardous Air Pollutant regulations. Ambient air monitoring is required under Nuclear Regulatory Commission guidelines. Based on this, it is expected that uranium, radionuclide and radon emissions from these facilities/operations is low and should pose no threat to the general public either locally or at a distance. However, as additional facilities become operational, the overall uranium, radionuclide and radon emissions in the Four Corners area will increase and may be significant.

Recommendations:

No recommendations for additional ambient air monitoring of uranium, radionuclides or radon are currently being proposed. However, as uranium mining and milling activities in the Four Corners region increase, this topic may need to be revisited.

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Mercury

Background:

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the Four Corners region have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness and Mesa Verde National Park, which are both Federal Class I Areas.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)(Figure 1)[2]. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate (Figure 3)[2]. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded[3]. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River (Figure 4)[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. The Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass, 10, 659 ft. elevation), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds from La Plata County to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Suggestions for Future Monitoring Work:

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the

NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

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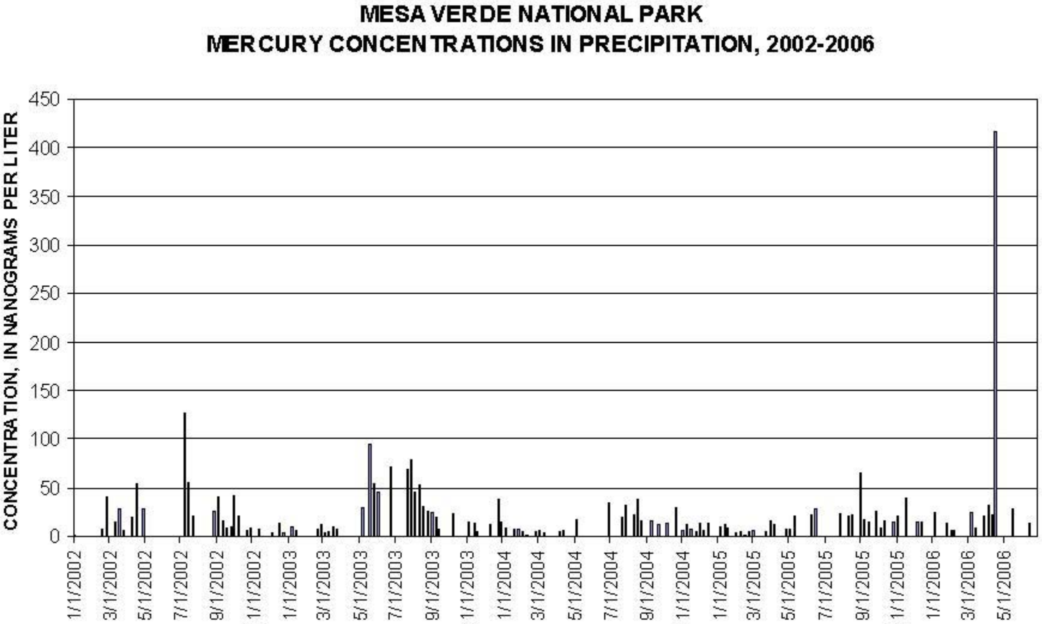
Figures



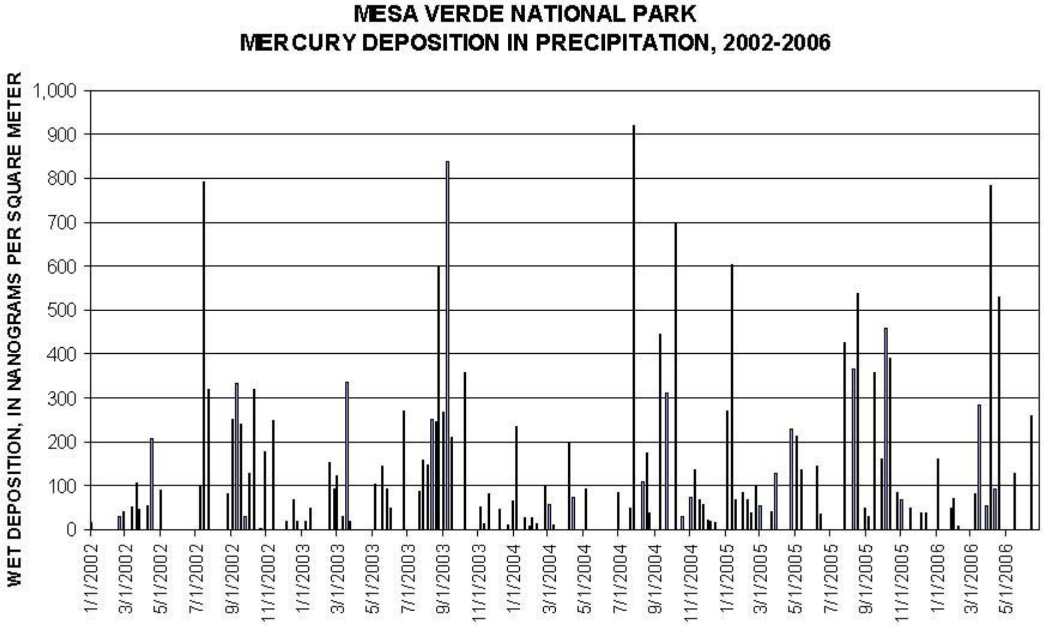


Figure 1. Concentrations and wet deposition of mercury at Mesa Verde National Park, 2002-2006. Data are from the National Atmospheric Deposition Program, Mercury deposition Network.

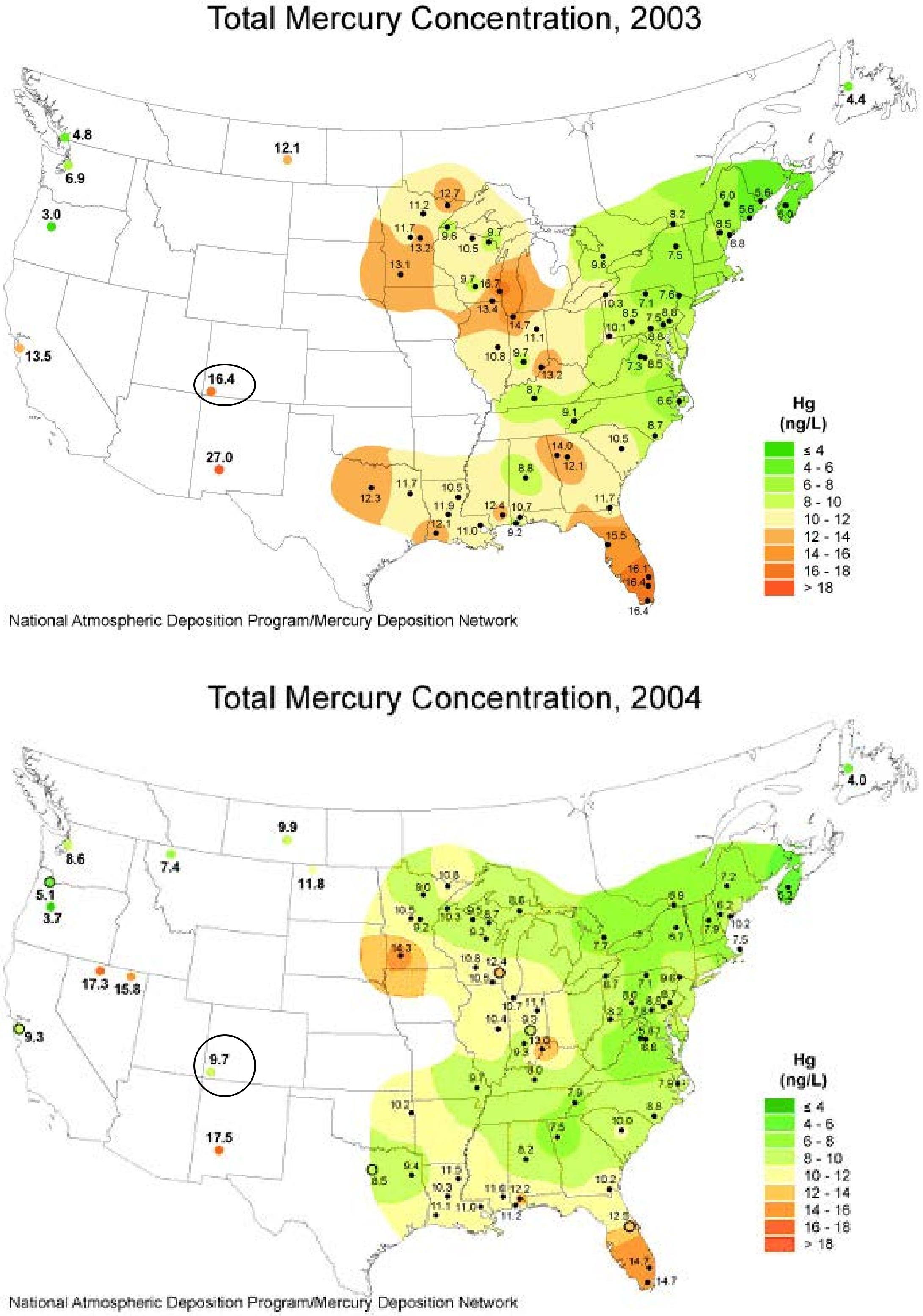
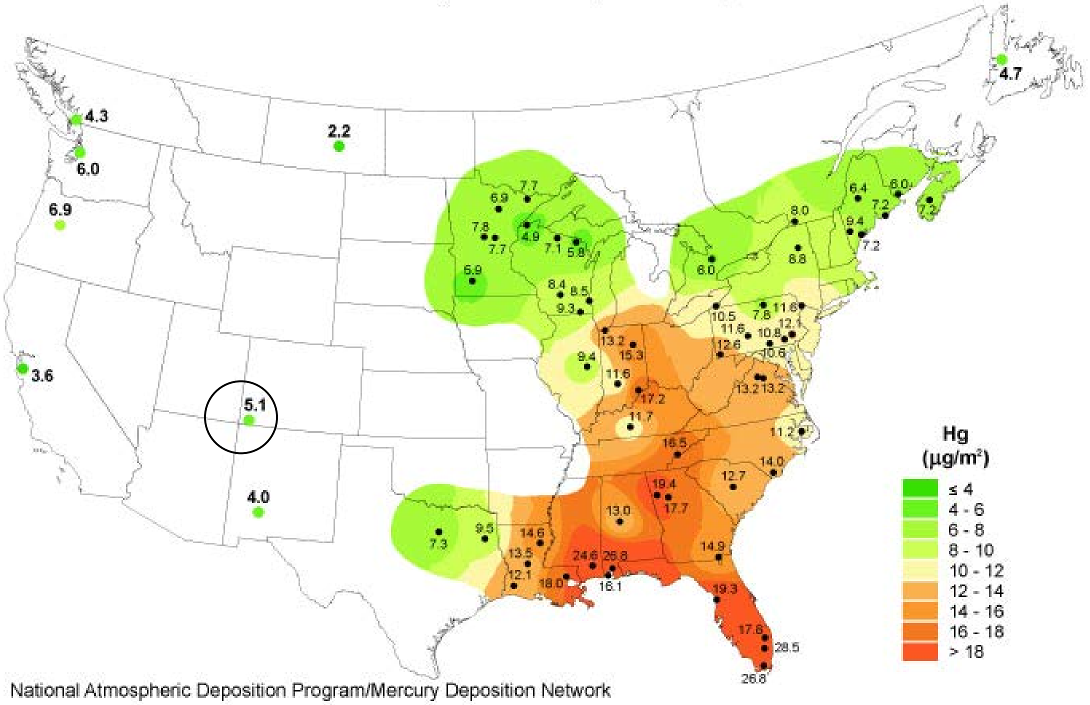


Figure 2. Volume-weighted mean concentrations of mercury in wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled.

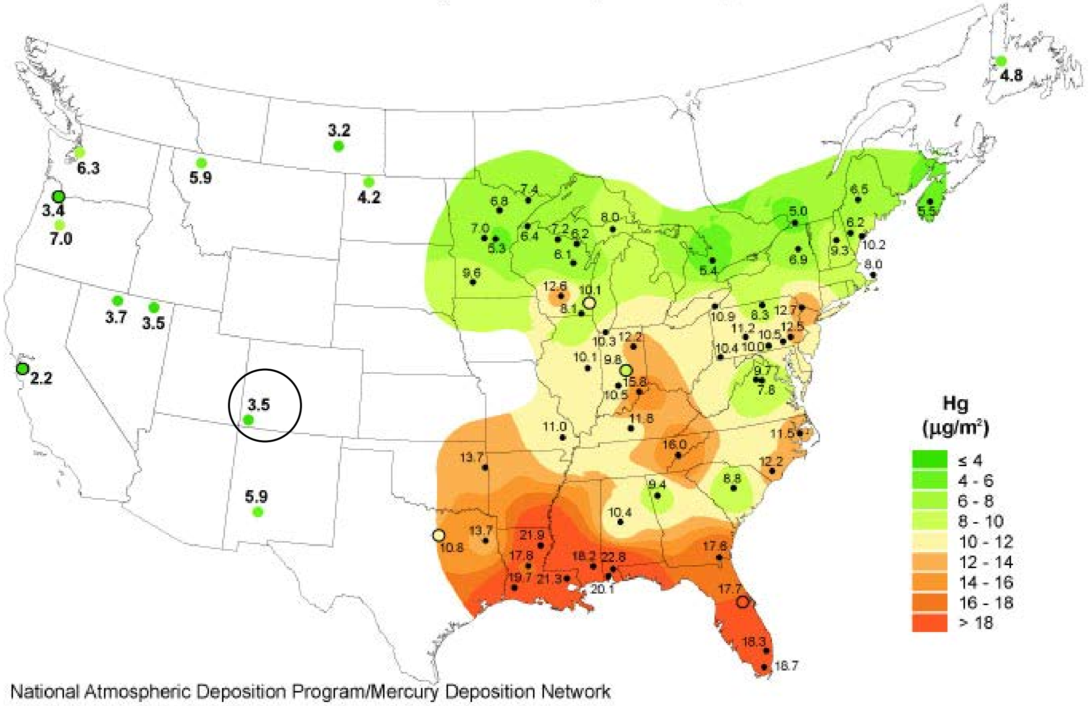
The years 2003 and 2004 represent “high” and “low” average annual concentrations for the Park’s short data record, 2002-2006.

Total Mercury Wet Deposition, 2003



National Atmospheric Deposition Program/Mercury Deposition Network

Total Mercury Wet Deposition, 2004



National Atmospheric Deposition Program/Mercury Deposition Network

Figure 3. Total mercury wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled. While concentrations are high (Figure 2), total wet deposition of mercury is low to moderate due to low precipitation amounts at Mesa Verde.

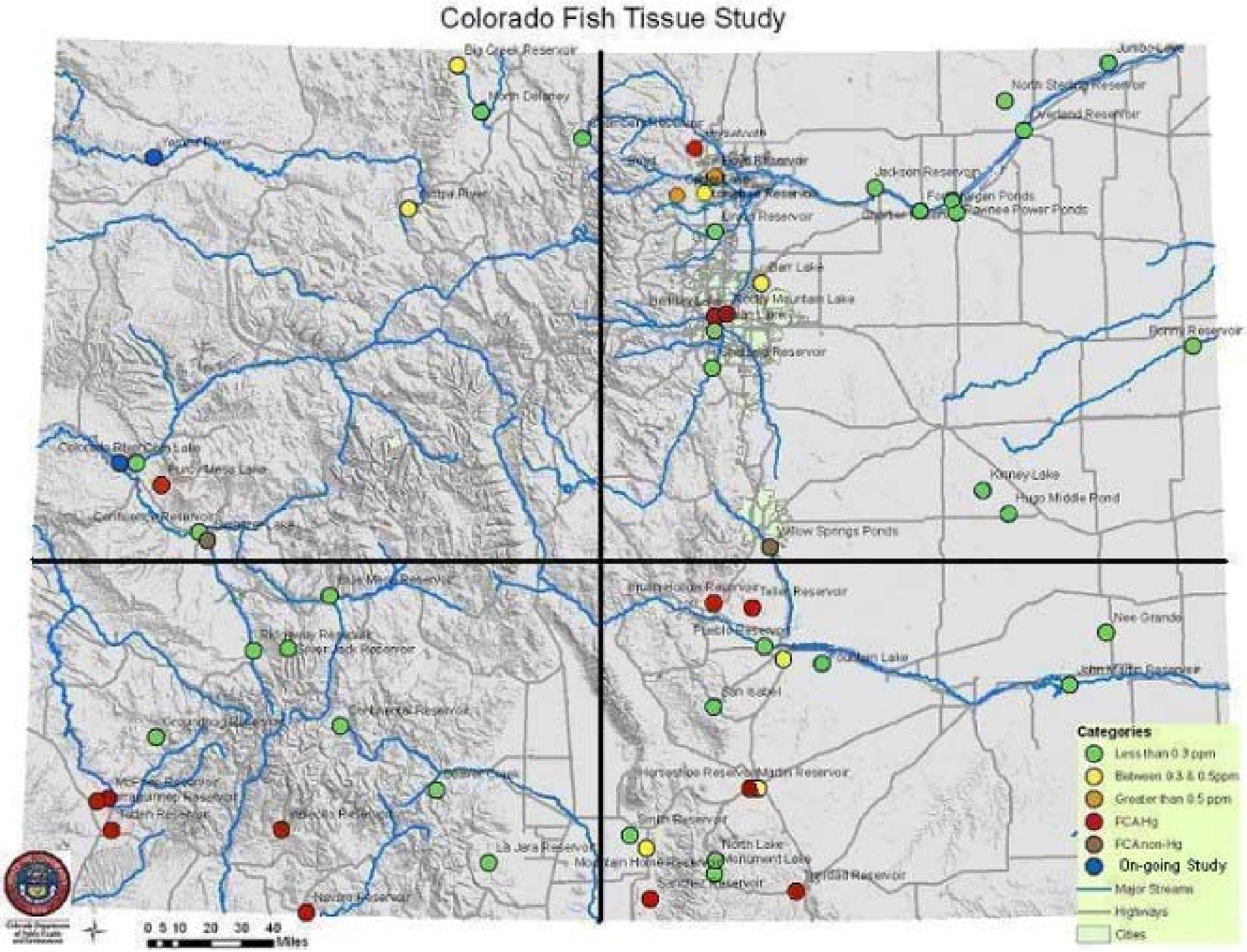


Figure 4. Results of a study by the Colorado Department of Public Health and Environment (CDPHE) measuring mercury concentrations in fish tissue in selected water bodies. The sites marked in red already have consumption advisories posted on them. Advisories are triggered by having a mercury level of 0.5 parts per million or more. The sites in orange have a similar mercury concentration to the red and are in the process of having consumption advisories posted on them as well. The sites marked in yellow have mercury levels between 0.5ppm and 0.3ppm. These are water bodies that the CDPHE is keeping a close watch on, although they are not recommending restricting consumption. The sites marked in green have mercury concentrations below 0.3ppm. The green sites are also not recommended for restricted consumption. Figure from CDPHE's Colorado Fish Tissue Study, http://www.cdphe.state.co.us/wq/FishCon/analyses/index.html.

Atmospheric Deposition of Nitrogen and Sulfur Compounds

Background:

Rationale:

Nitrogen (N) is an essential nutrient, but in elevated amounts it can cause harmful effects to ecosystems and human health. In areas with minimal human development, N in air deposition is a major contributor to N inputs to ecosystems, including surface waters. Air deposition includes wet deposition received with precipitation, but also includes dry deposition of gases and aerosols, through fall deposited under forest canopies, and condensation of cloud and fog. Atmospheric N mainly is deposited as nitrate, nitric acid, ammonium, and dissolved organic nitrogen. Key anthropogenic sources include nitrogen oxides (NOx) emitted from fossil fuel burning and ammonia volatized from fertilizer and animal wastes. NOx also will react with volatile organic compounds to form ozone (see ozone sub-chapter). Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems. Both N and sulfur (S) oxides can form "acid rain" and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Atmospheric deposition of S has decreased at many monitoring stations in the USA, especially in the eastern portion, since the implementation of the Clean Air Act Title IX Amendments. Despite a few locations with slight increases in S, amounts and concentrations of sulfate in wet deposition generally are low in the western USA. In contrast, concentrations of nitrate and ammonium in wet deposition have increased at some monitoring stations in the USA, including many in the western portion (Figures 1-3).[1, 2]

Harmful ecological effects of elevated N deposition have been documented in the western United States in regions downwind of emissions hotspots, including both high and low-elevation ecosystems[3]. These effects include high nitrate concentrations in streams and lakes, reduced clarity of lakes, altered and less diverse aquatic algal and terrestrial plant communities, loss of N from soils via leaching and gas flux, increased invasive species, changed forest carbon cycle and fuel accumulation, altered fire cycles, harm to threatened and endangered species, and contribution to regional haze and ozone formation[3]. In the Colorado Front Range, including the east side of Rocky Mountain National Park, harmful ecosystem effects attributed to increased N deposition specifically include: chronically elevated levels of nitrate in surface waters, altered types and abundances of aquatic algal species (diatoms), elevated levels of N in subalpine forest foliage, long-term accumulation and leaching of N from forest soils, and shifts in alpine plants from wildflowers to more grasses and sedges[3,4,5]. Hindcasting of deposition trends estimate that the harmful effects in the CO Front Range began when N in wet deposition increased above the 1.5 kg/ha/yr threshold[6]. An ecological critical load is the quantitative estimate of an exposure to one or more pollutants below which significant harmful effects on specified sensitive elements of the environment do not occur according to present knowledge[7]. Rocky Mountain National Park has adopted 1.5 kg/ha/yr of N in wet deposition as its ecological critical load[8] and the Colorado Department of Public Health and Environment's Air Pollution Control Division is now working to reduce N deposition loads to the Park[9].

Existing N & S deposition and ecological effects data for the Four Corners and San Juan Mountain region:

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program (NADP)[10]. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network (CASTNet). Concentrations of airborne aerosols such as ammonium nitrate and ammonium sulfate are reported as part of the Interagency Monitoring of Protected Visual Environments (IMPROVE) program at Mesa Verde National Park and a site near Durango Mountain Resort (Weminuche Wilderness).

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing (Figure 4)[10,11]. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for

Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado (Figure 5)[12].

Inorganic water chemistry for Wilderness Lakes has been collected by the USDA-National Forest Service and US Geological Survey and over 15 years of data have accumulated for some lakes. While some of this data has been compared to high-elevation lake water chemistry in other regions of Colorado and Wyoming[13], a full analysis has not been completed. Furthermore, the data are insufficient to detect potential changes to lake biology.

Data Gaps: While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work:

C. Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

D. Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

E. Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

F. Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc. (see Fenn et al. 2003)[3].

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Figures

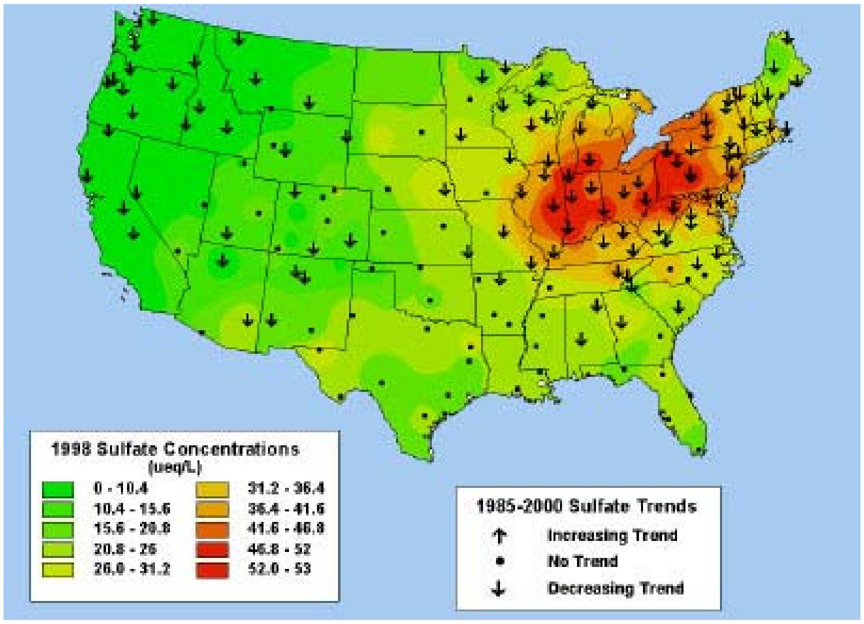


Figure 1. Trends in sulfate concentrations in wet deposition, 1985-2000. Sulfate concentrations are low in the Four Corners region and either show no trend or a decreasing trend over time.[2]

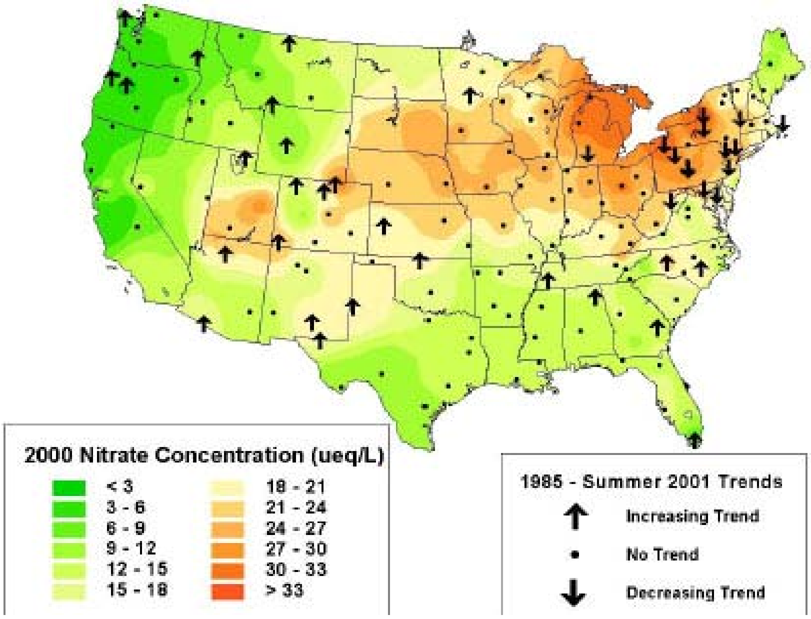


Figure 2. Trends in nitrate concentrations in wet deposition, 1985-2001. Nitrate concentrations are moderate in the Four Corners Region and show either no trend or an increasing trend over time.[2]

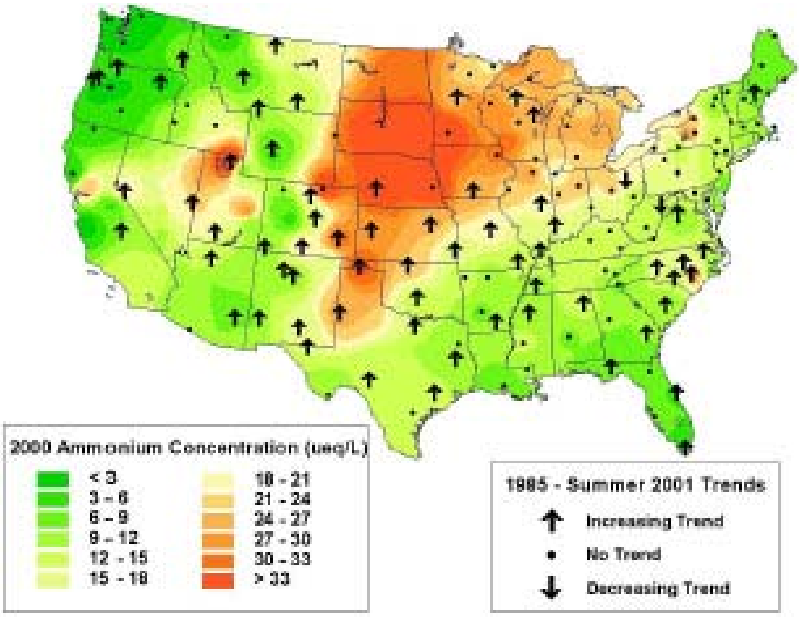


Figure 3. Trends in ammonium concentrations in wet deposition, 1985-2001. Ammonium concentrations are low in the Four Corners Region but show an increasing trend over time.[2]

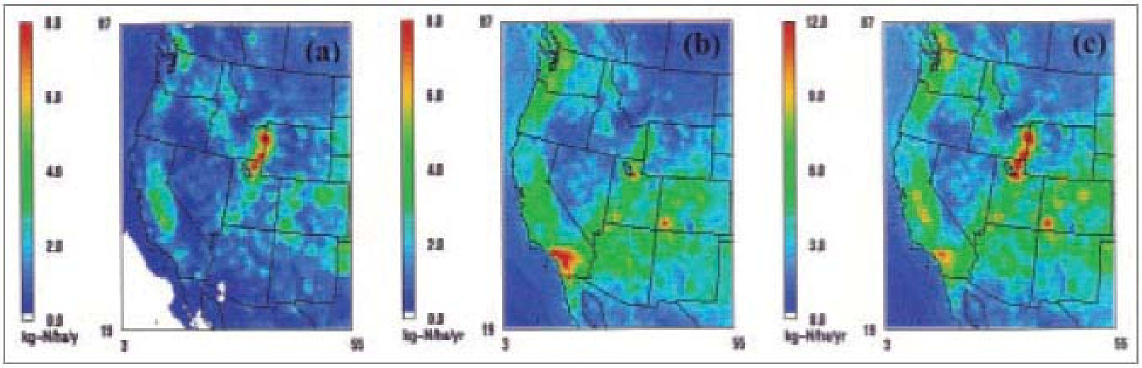
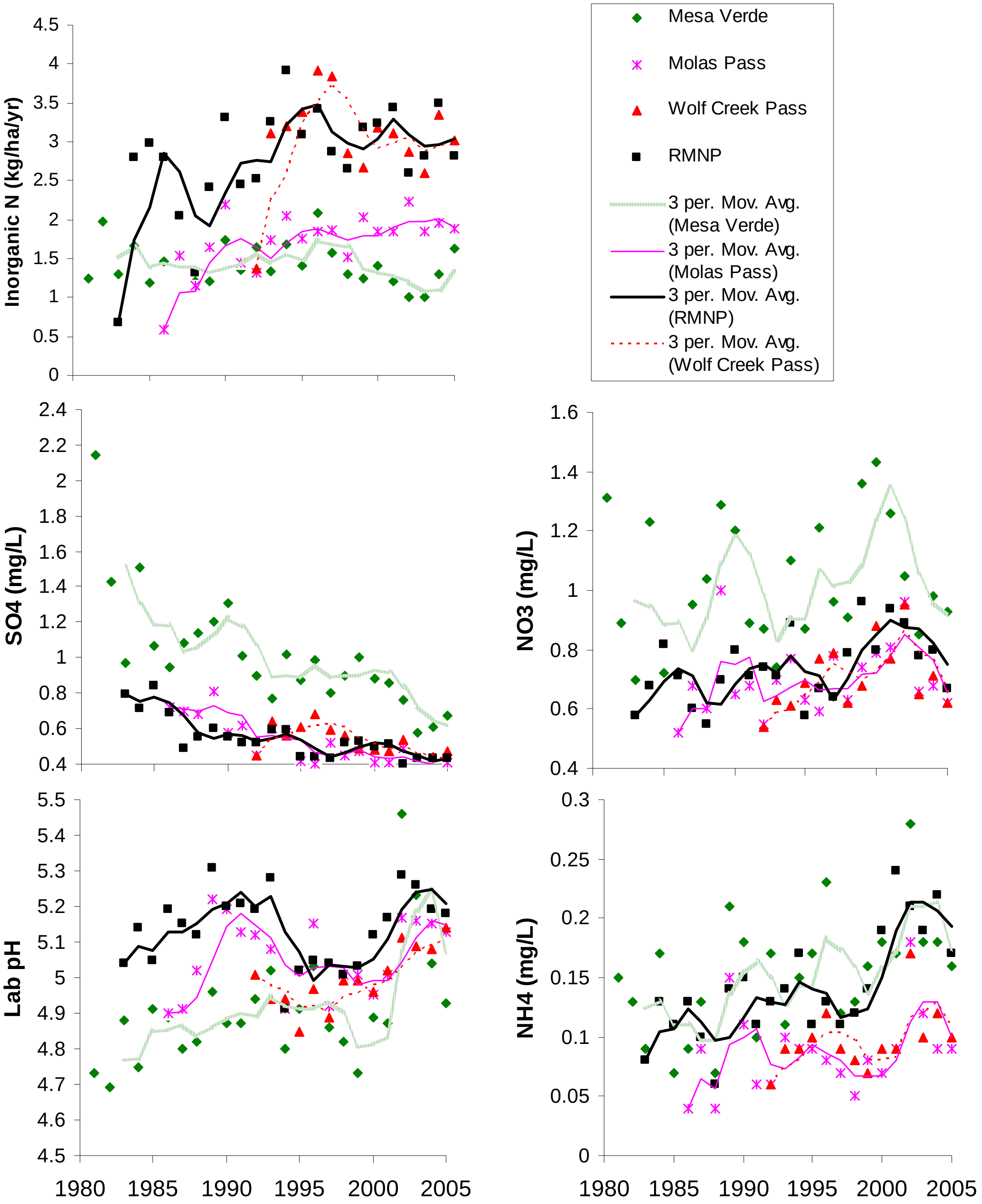


Figure 4. Model-simulated annual nitrogen deposition (kg/ha/yr) in the western United States in 1996 for (a) total wet and dry deposition of N from ammonia and ammonium, (b) total wet and dry deposition of N from nitric oxide, nitrogen dioxide, nitric acid, and nitrate, and (c) total N deposition calculated as the sum of (a) and (b).[13]

Figure 5. Annual averages of total inorganic nitrogen, pH, and sulfate nitrate, and ammonium concentrations in wet deposition from Mesa Verde National Park, Molas Pass, Wolf Creek Pass, and Rocky Mountain National Park (RMNP). Concentrations are precipitation volume-weighted means. Trend lines are 3 period moving averages and are not meant to indicate presence or absence of statistical trends. RMNP is included for comparison as a location where ecological effects of nitrogen deposition are documented.



Additional figures for Mesa Verde National Park based on data from the National Atmospheric Deposition Program:

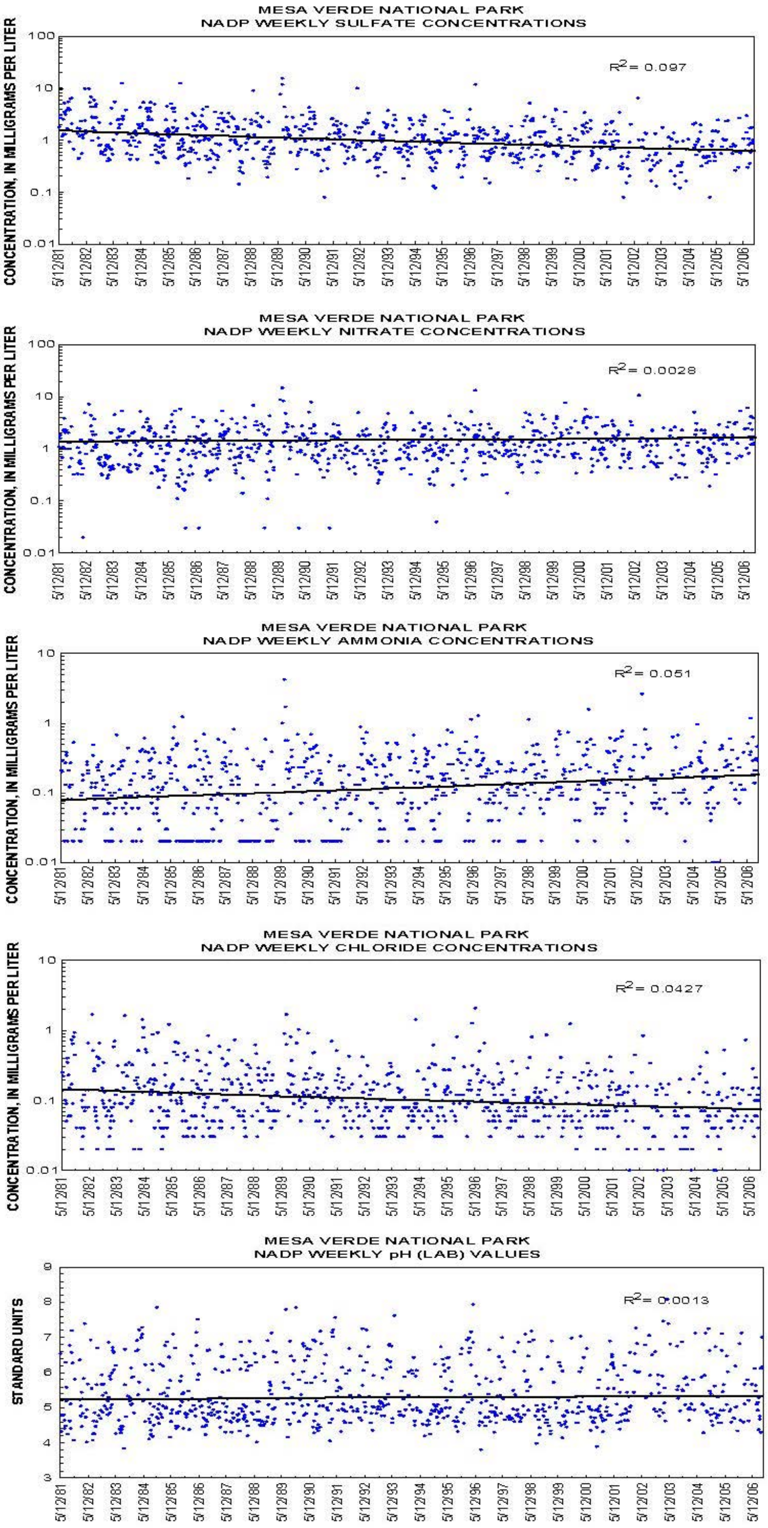


Figure 1. Weekly concentrations of selected constituents in wet deposition at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program.

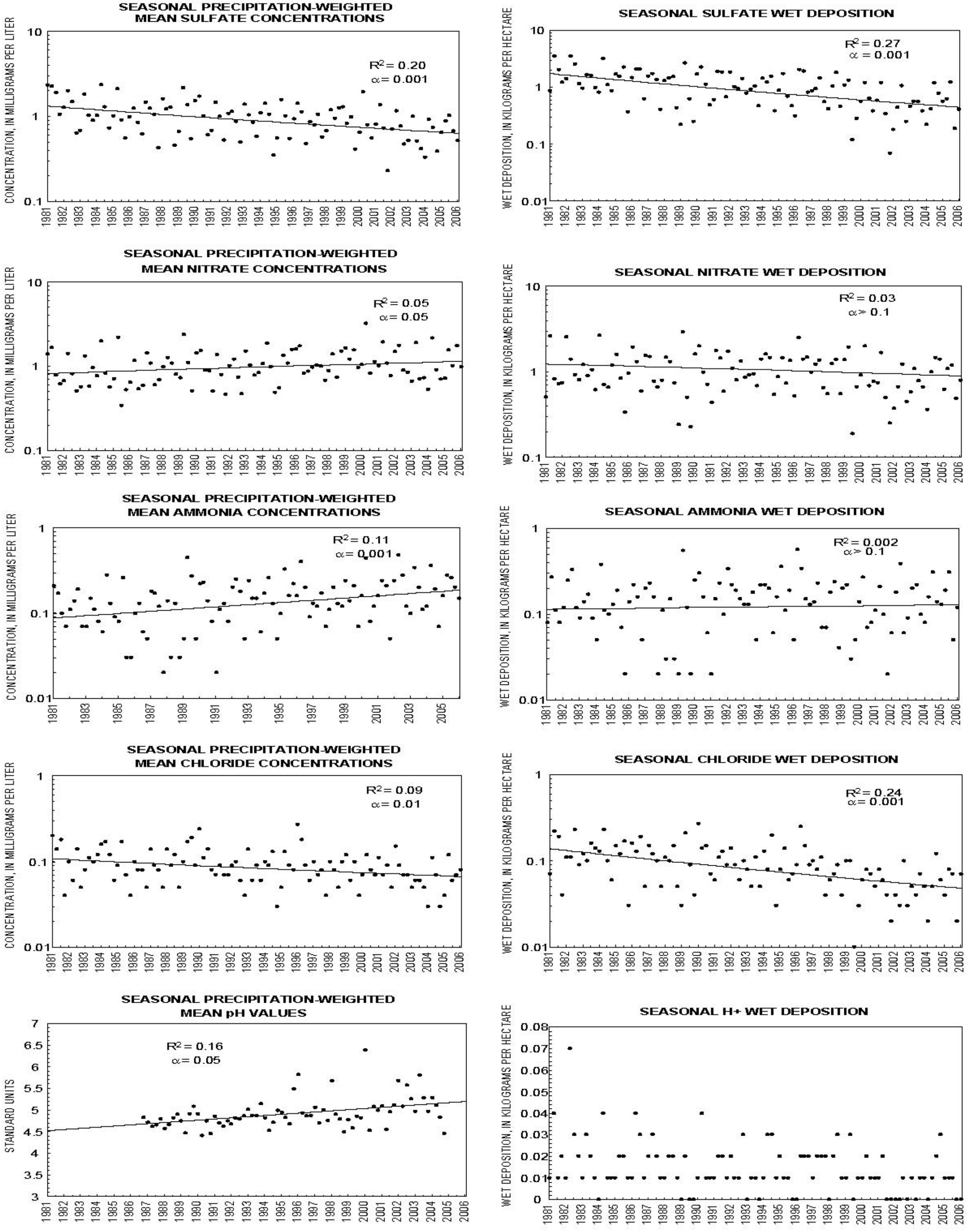


Figure 2. Seasonal concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

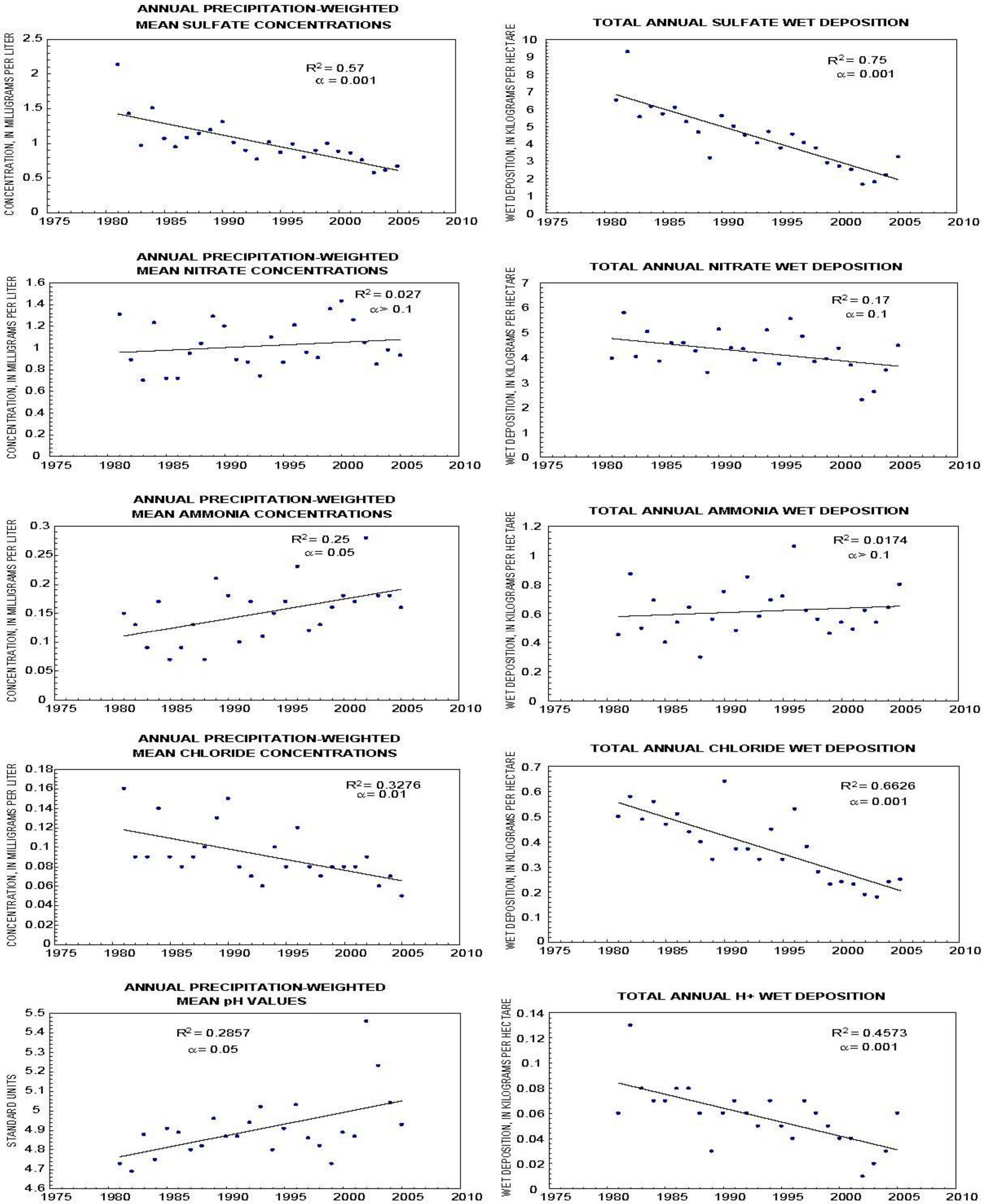


Figure 3. Annual concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

Visibility

I. Background

Title 42 U.S.C. §§ 7491 and 7492 of the Clean Air Act established a national policy to study and protect visibility in Federal class I areas. It declares as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[1] Of several mandatory class I areas Federal areas on the Colorado Plateau, Arches National Park, Canyonlands National Park, the Weminuche Wilderness, and Mesa Verde National Park lie within near or immediate proximity to the Four Corners Region.

Several planning and monitoring authorities have evolved from this statutory requirement, two of which are able to directly address visibility concerns in the Four Corners region. The Interagency Monitoring of Protected Visual Environments (IMPROVE) program was initiated in 1985, and has implemented an extensive long term monitoring program in the National Parks and Wilderness Areas.[2] Additionally, the Western Regional Air Partnership (WRAP) was formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission, and promotes the implementation of recommendations that were made in the previous commission.[3] Specifically, the WRAP partnership is implementing a regional planning process to improve visibility in all western Class I areas "by providing the technical and policy tools needed by states and tribes to implement the federal regional haze rule."[4]

EPA issued the final Regional Haze Rule on April 22, 1999.[5] "The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment."[6] This regulation is also anticipated to have the additional benefits of improving visibility outside of class I areas, as well as ameliorating the health impacts associated with fine particulates (PM 2.5).[7]

II. What affects visibility and how is it monitored?

The interaction between certain gasses, particulate matter, and the light that passes through the atmosphere yields the basic processes through which visibility is affected. Gasses and *aerosols* may scatter or block sunlight through *diffraction, absorption,* and *refraction*. When sunlight encounters gasses and aerosols, it scatters preferentially as a function of the size of the particles that it encounters.[8] The relationship between particulate size and light is extremely important, as it ultimately accounts for changes in color and *haze*. Although the total mass of coarse particles (PM 10) in the atmosphere outnumbers the total mass of fine particles (PM 2.5), the finer particles "are the most responsible for scattering light" because they scatter light more efficiently, and because there are more of them.[9] Consequently, the origin and transport of fine particles (PM 2.5) is of greatest concern when assessing visibility impacts.[10]

In the most general sense, visibility is the effect that various aerosol and lighting conditions have on the appearance of landscape features.[11] While photography is the simplest method used to convey visibility impairment, it is difficult to garner quantitative information from photographs, digital pictures, or slides. Because some direct measurement of the atmosphere's optical qualities is desired, most visibility programs include a measure of either atmospheric *extinction* or *scattering*.

> The *scattering coefficient* is a measure of the ability of particles to scatter photons out of a beam of light, while the *absorption coefficient* is a measure of how many photons are absorbed. Each parameter is expressed as a number proportional to the amount of photons scattered or absorbed per distance. The sum of scattering and absorption is referred to as *extinction* or attenuation.[12] (Emphasis added.)

Extinction is measured by devices such as the *transmissometer* and *nephelometer*. Most monitoring programs use combinations of these devices to measure extinction and scattering. Extinction is usually described in terms of *inverse megameters* (Mm^{-1}), and is proportional to the amount of light that is lost as it travels over a million meters.[13] *Deciviews* is another measurement of extinction, but which is scaled in a way that it is perceptually correct. "For example, a one deciview change on a 20 deciview day will be perceived to be the same as on a 5 deciview day."[14] Because deciviews are *scaled* so that they may describe *changes* in visibility, they must be distinguished from extinction as it can otherwise be described in inverse megameters and *visual range*.

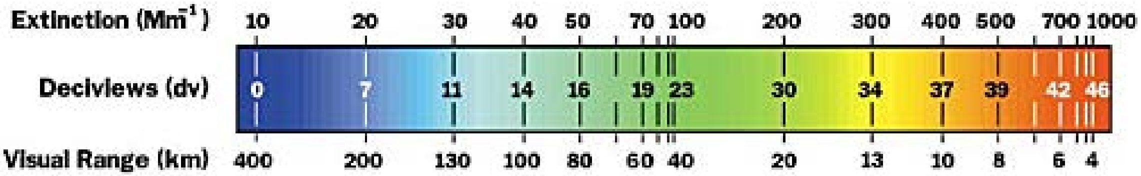


Fig. A Comparison of extinction (Mm^{-1}), deciview (dv), and visual range (km).
(Source: Malm, William C. Introduction to Visibility.)

In addition to the measurements of scattering and extinction, it is also helpful to know what materials in the air are contributing to visibility impairment. *Particle measurements* are normally made in conjunction with optical measurements "to help infer the cause of visibility impairment, and to estimate the source of visibility reducing aerosols."[15] The size and composition of particles are the most commonly identified characteristics that are used in visibility monitoring programs. Additionally, "particles between 0.1 to 1.0 microns are most effective on a per mass basis in reducing visibility and tend to be associated with man-made emissions."[16] These fine particles are usually grouped under the category PM 2.5, which refers to particles that are less than 2.5 microns large. (As discussed earlier, PM 2.5 particles are in general the most effective in scattering light due to their small size.) "The IMPROVE fine particle modules employ a cyclone at the air inlet which spins the air within a chamber. Fine particles are lifted into the air stream where they are siphoned off and collected on a filter substrate for alter analysis."[17] Once the size of particles has been measured, they are speciated by composition. The identification of sulfates, nitrates, organic material, elemental carbon (soot) and soil "helps determine the chemical-optical characteristics and the ability of the particle to absorb water (RH effects) and is important to separate out the origin of the aerosol."[18]

> A visibility impairment value is calculated for each sample day. To get a valid measurement, all four modules must collect valid samples. The regional haze regulations use the average visibility values for the clearest days and the worst days. The worst days are defined as those with the upper 20% of impairment values for the year, and the clearest days as the lowest 20%. The goal is to reduce the impairment of the worst days and to maintain or reduce it on the clear days.[19]

For data to be considered under the regional haze regulations, it must meet the minimum criteria for the number of daily samples needed in a valid year: 1.) 75% of the possible samples for the year must be complete; 2.) 50% of the possible samples for each quarter must be complete; 3.) No more than 10 consecutive sampling periods may be missing.[20]

As noted above, the filter analysis provides the concentrations and composition of atmospheric particles. The *source contribution* to visibility impairment can be indicated from the analysis of trace elements:

vanadium/nickel » petroleum-based facilities, autos
arsenic » copper smelters
selenium » power plants
crustal elements » soil dust (local, Saharan, Asian)
potassium (nonsoil) » forest fires[21]

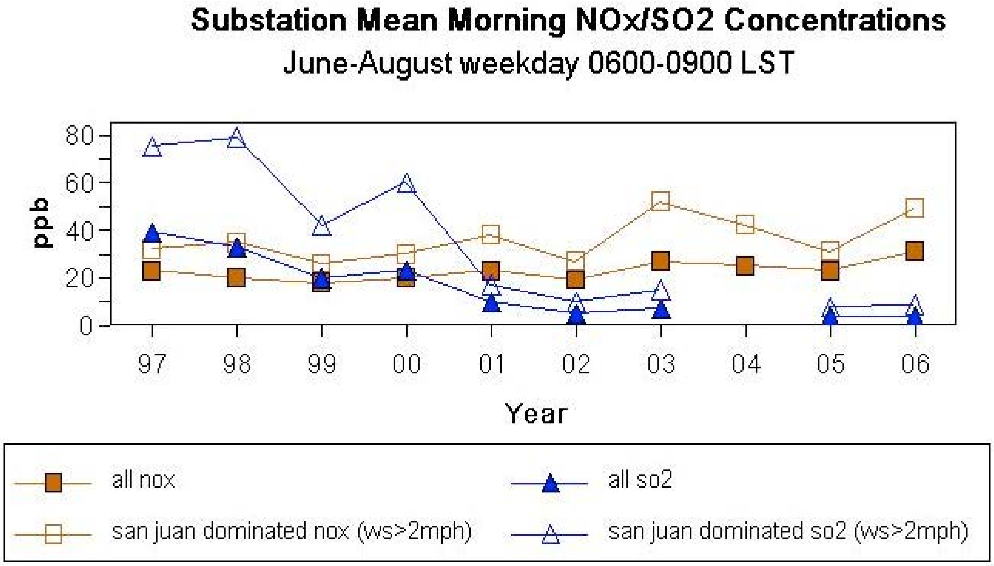
III. Visibility in the Four Corners

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE's optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

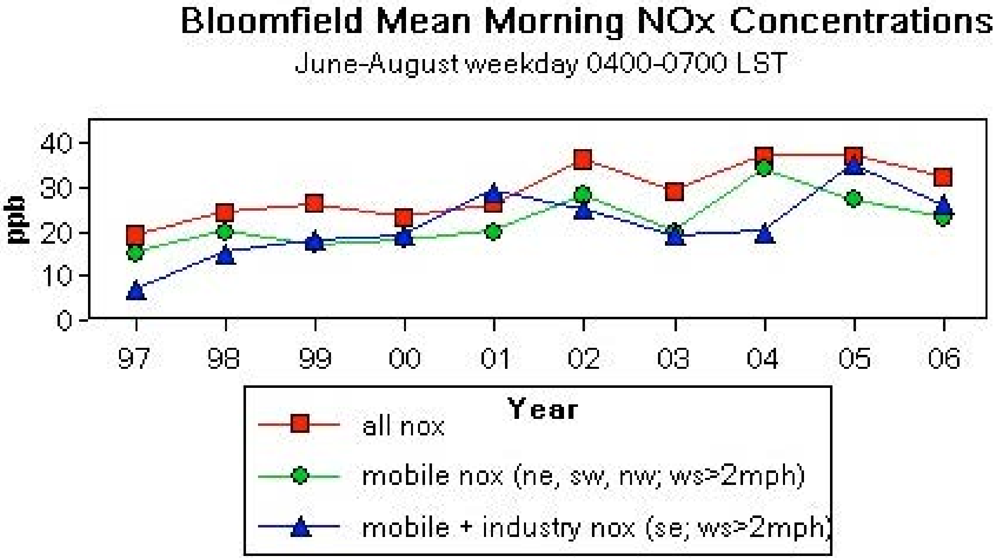
Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2:



For the same time period, similar increases in NOx have been observed in Bloomfield, and it appears that NOx may be slowly increasing as a regional trend:

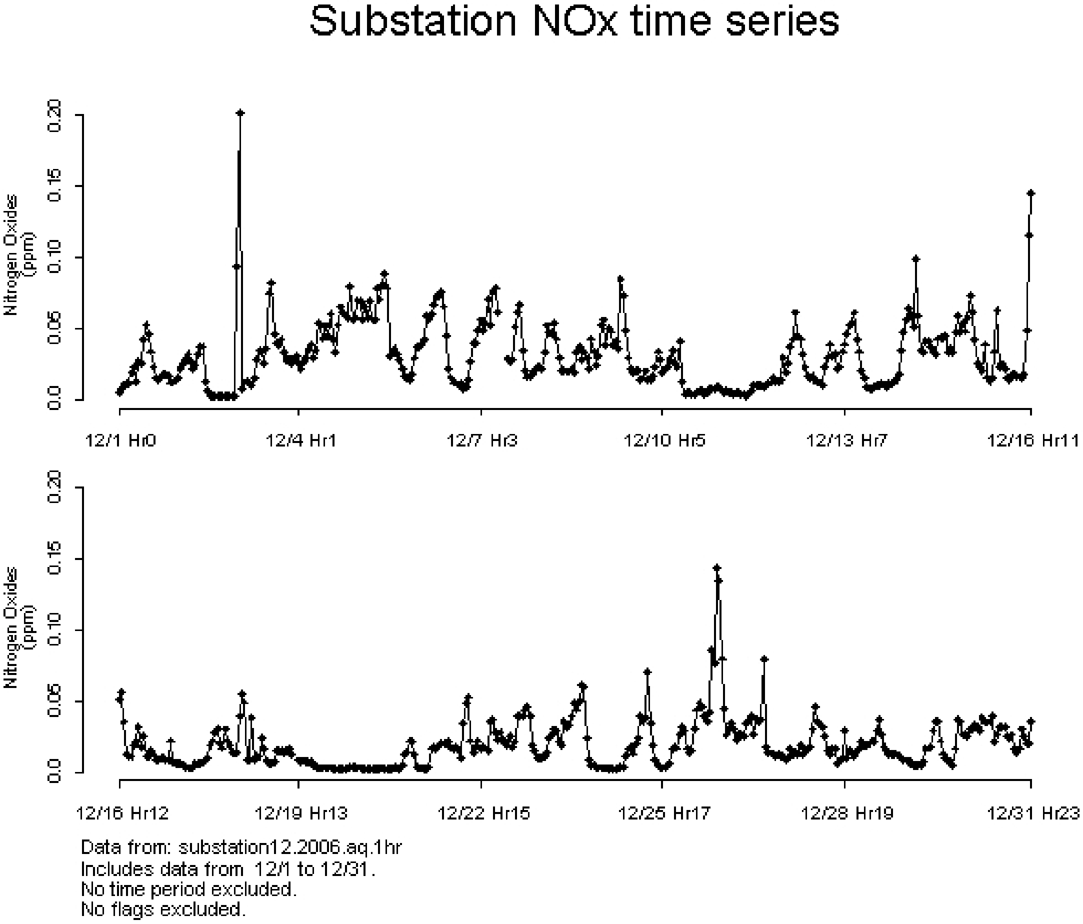


Many citizen's accounts on deteriorating visibility in the Four Corners have centered upon wintertime episodes. The ways in which seasonal differences may impact visibility is very important. In the summertime, the "confining layer" of the atmosphere, which generally holds pollutants below a certain altitude, is much higher. Additionally, the extra heat associated with warmer seasons allows the atmosphere to move and mix more readily. The result is that, in the summertime, visibility-impairing pollutants can mix more easily, and dilute within in a greater vertical distance. Conversely, in the wintertime, that confining layer is usually much lower (thus the prevalence of wintertime inversions.) In colder seasons, the atmosphere does not move or mix as easily. Therefore, generally, wintertime pollutants are held closer to the ground level, and they cannot readily dilute into the upper atmosphere. Given this effect, the same level of regional emissions year-round will likely be more noticeable in the winter as *layered haze*. The addition of rising emissions levels will compound this effect in the wintertime.

Wintertime haze near Kline, Colorado. 12/05/2006. *See also*: A Resident's Observation of Visibility, this section.

Excellent visibility, photo taken one mile west of previous photo. 10/21/2006.

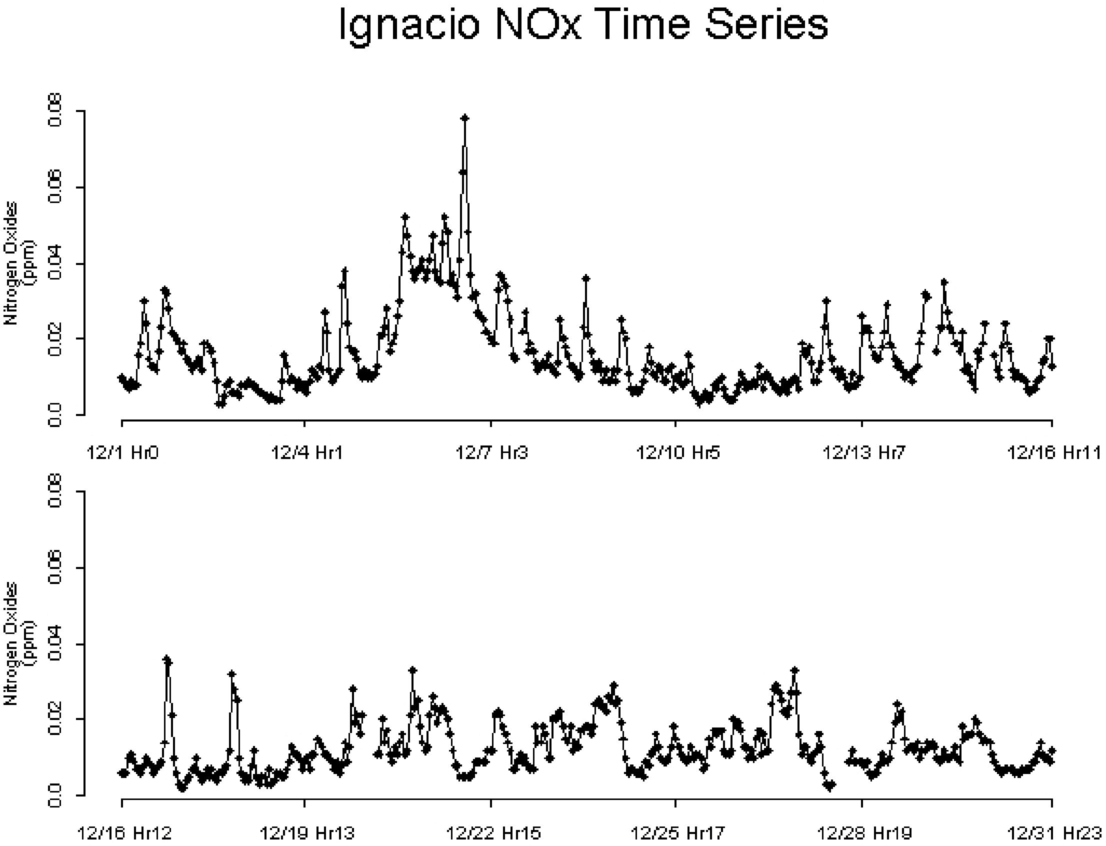
The considerations outlined above reasonably lead to the hypothesis that citizens' accounts of deteriorating visibility, as they are specific to wintertime episodes, may be partially caused by increasing NOx emissions. For an initial test of this hypothesis, we may review what NOx concentrations existed in the region at the time of the 12/05/2006 photograph:



Substation NOx time series

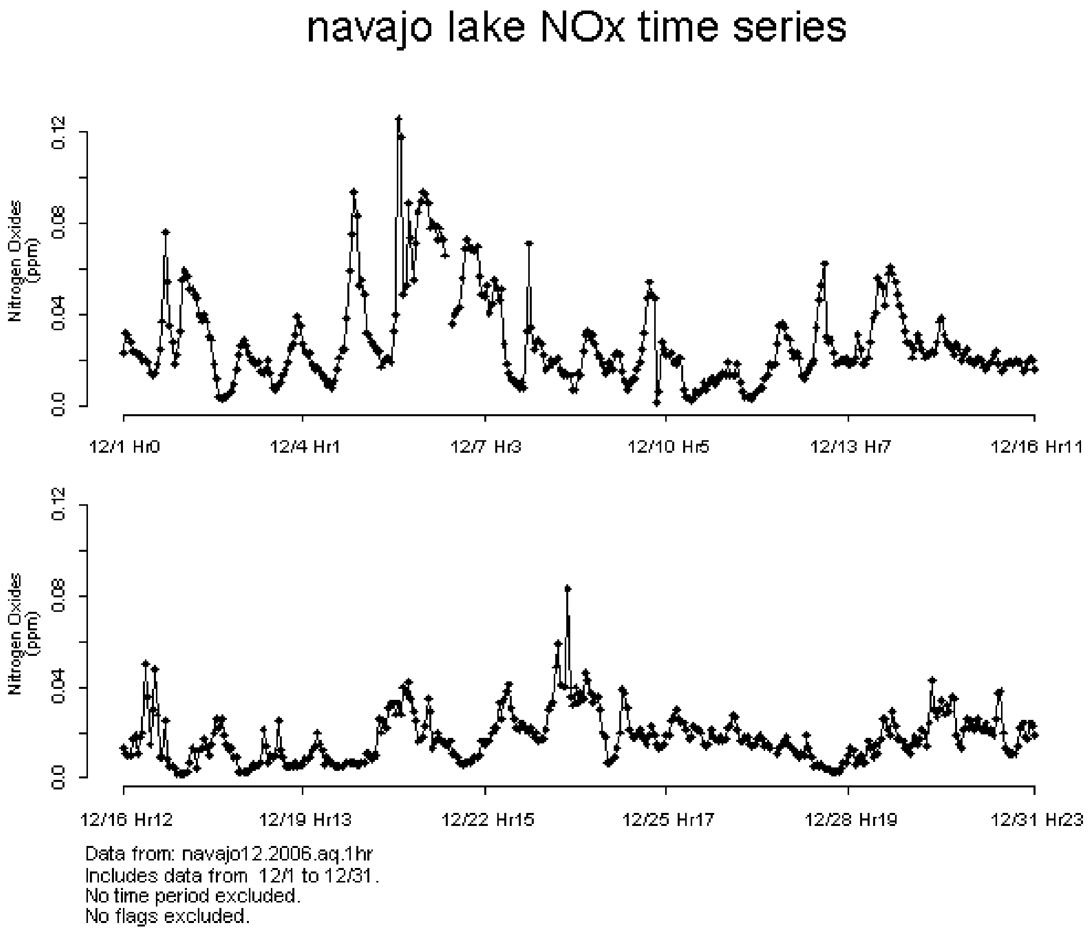
Data from: substation12.2006.aq.1hr
Includes data from 12/1 to 12/31.
No time period excluded.
No flags excluded.

Elevated NOx concentrations existed at the San Juan Substation, with the most pronounced event occurring approximately 48 hours before the 12/05/2006 photograph.

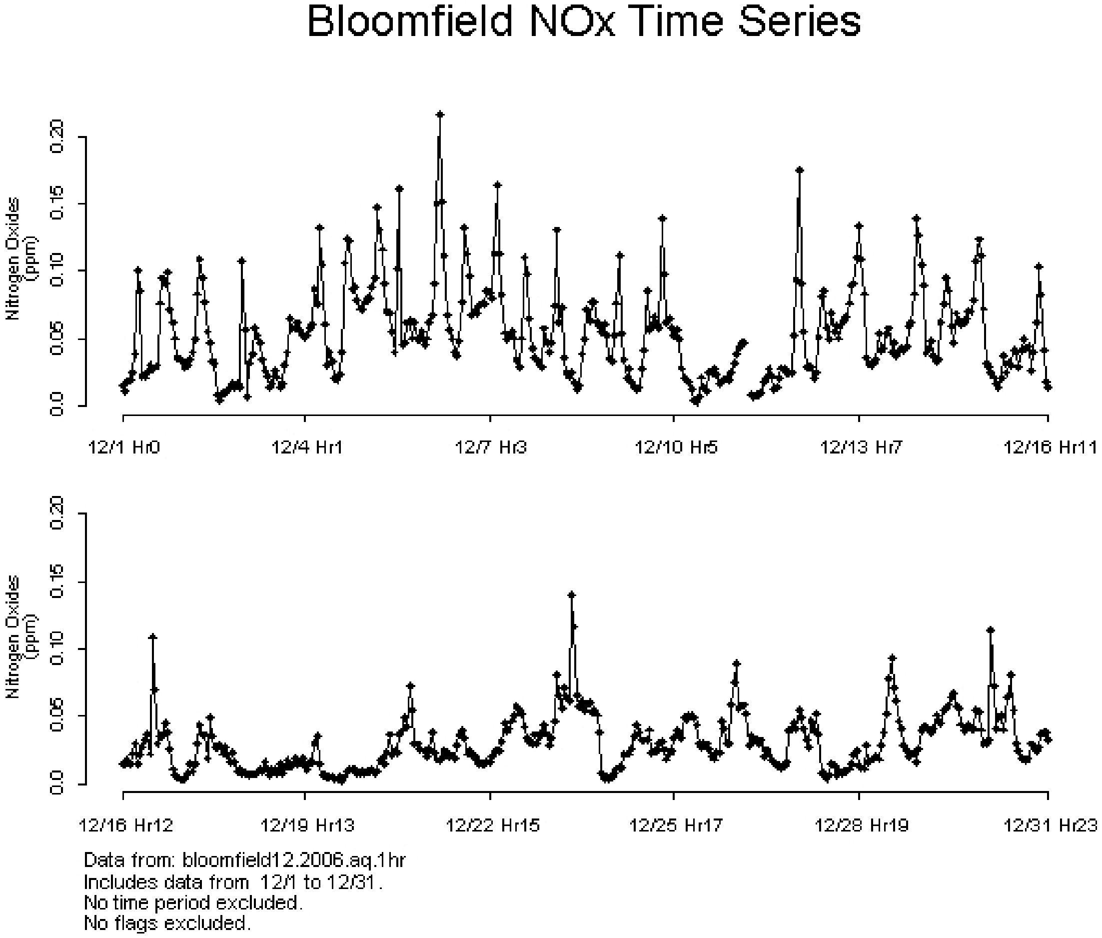


Data from: ignacio12.2006.aq.1hr
Includes data from 12/1 to 12/31.
No time period excluded.
No flags excluded.

Elevated NOx concentrations existed at the Ignacio monitoring site approximately 24 hours after the 12/05/2006 photograph.



Elevated NOx concentrations existed at the Navajo Lake monitoring site, with the most pronounced concentrations occurring on 12/05/2006.



Bloomfield NOx Time Series

Data from: bloomfield12.2006.aq.1hr
Includes data from 12/1 to 12/31.
No time period excluded.
No flags excluded.

Elevated NOx concentrations existed at the Bloomfield monitoring site, with the most pronounced concentrations occurring within 24 hours of the 12/05/2006 photograph.

It appears that NOx concentrations were a contributing factor behind the visibility impairment episode documented in the 12/05/2006 photograph. These preliminary observations raise a number of additional considerations. First, there exists a great value in the photographic documentation of visibility. These elevated NOx concentrations might not have been considered if one were to only examine particulate data over a given time period. *Visual observations*, although subjective, provide the first clue that will lead the inquisitor to examine specific episodes and time periods. The contemplation of criteria such as color, location, and the *expanse* of impairment episodes considers the *regional nature* of visibility impairment in a way that no site-specific particulate measurement can do. In a sense, visual accounts and photographic documentation is a *top-down* approach that reveals what data needs to be specifically considered, and where additional monitoring would be useful.

Second, in the case of indeterminate deciview trends at Mesa Verde, the preceding discussion on photographic documentation obliges us to consider the monitoring site's location. Mesa Verde is situated upon the uppermost reaches of the *Four Corners Platform*. This geologic plateau rises above the valleys and basins of the Four Corners region, and typifies the area's rugged and varied topography. The monitoring site at Mesa Verde is located at roughly 7,200 feet above sea level, while most emissions in the region occur in the San Juan Basin to the south, at roughly 5,000 feet. (Likewise, most other emissions in the region are related to human activity, and occur in the other multiple valleys and basins that are topographically separated from the Park.) Given the occurrence of wintertime inversions and a lower confining atmospheric layer, it is entirely possible that what is observed as severe visibility impairment will not be recorded at Mesa Verde, because the monitoring site will be *above the confining layer*. The absence of photographic documentation coexistent with particulate measurements in the Park causes that data to be extrapolated from air quality within the Park itself, and it will not effectively consider what an observer might actually see as she looks across the region from that location.

It is reasonable to assume that (wintertime) visibility impairment in the Four Corners is exacerbated by the area's rugged topography, which often confines visibility impairment to within the region's numerous basins and deep valleys. Additionally, that visibility monitoring in the Four Corners which is reliant on particulate measurements is located at higher elevations, and is not likely to record events related to low confining layers and atmospheric inversions. (I.e. Mesa Verde and the Weminuche.) These locations are, however, great *vantage points* from which visibility may be observed, but they forgo this opportunity because they do not include photographic documentation. Furthermore, Canyonlands National Park is not a good location to observe visibility as it relates to the Four Corners, because it is too distant from the region. (Both the path of emissions transport and line of sight from the Four Corners to Canyonlands is blocked by the higher elevations surrounding the Blue Mountains and Bear's Ears.) That leaves only one site—the Shamrock Mine—from which visibility in the Four Corners Region can be satisfactorily observed and documented year-round.

IV. Suggestions for Future Monitoring Work

Air quality monitoring is a rather expensive operation, and so resources that might provide for saturation studies or additional permanent monitoring should be allocated in consideration of monitoring goals as a whole. However, it is still reasonable to advocate some additional monitoring of visibility, as most of the following suggestions could be incorporated into existing sites.

Last, most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is suggested that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

    1. could be incorporated into existing monitoring sites;
    2. should include photographic documentation;
    3. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

V. Works Cited:

1. 42 U.S.C. § 7491 (a)(1).
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3. http://www.wrapair.org/facts/index.html (access date 4/05/2007).
4. Id.
5. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm (access date 4/05/2007). *See also* http://www.epa.gov/air/visibility/program.html.

6. http://www.epa.gov/air/visibility/program.html (access date 4/05/2007).
7. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm
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10. Id. at 9.
11. Id.
12. Id. at 27.
13. Id.
14. Id. at 35.
15. Id.
16. Id. at 28.
17. Id. at 28, 29.
18. IMPROVE 2007 Calendar.
19. Malm at 29.
20. IMPROVE 2007 Calendar.
21. Id.
22. Id.

The complete photographic record prepared by Erich Fowler is available by contacting Mark Jones at mark.jones@state.nm.us. This is a very large file (over 100 MB).

Mitigation Option: Interim Emissions Recommendations for Ammonia Monitoring

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Implement an ambient monitoring program for ammonia

C. Assess importance of ammonia to visibility
D. Visibility modeling would be more accurate if ammonia data were available
E. Ammonia emission impacts from NSCR can be better evaluated
F. US EPA Region 6 will assist with this effort

Evaluate data on ammonia emissions from engines less than 300 HP equipped with NSCR

- Testing should be done in the field
- Funding would need to be secured
- A contractor to make measurements would need to be found

II. Description of how to implement

The ambient monitoring program for ammonia would be conducted under the auspices of EPA Region 6. The appropriate agencies to implement this are EPA Region 6 and the New Mexico and Colorado departments of environmental quality. Collecting data on ammonia emissions from engines less than 300 HP would be voluntary and funding would need to be secured.

III. Feasibility of the Option

The technical feasibility of the ambient monitoring has already demonstrated. Specifically, the technical feasibility of measuring ammonia emissions from engines with NSCR has been demonstrated as part of a research project initially started by Colorado State University. However the exact methodology is not yet chosen. The environmental feasibility is negligible since only samples are collected. The economic feasibility depends on finding someone to pay for the sampling program

IV. Background data and assumptions used

The ambient monitoring would be conducted either by collecting samples or by real time analysis depending on equipment selected. Approximate measurements can be made using sampling tubes similar to Draeger tubes. The assumption is that a baseline ammonia level should be established and that potential increases may be observed because of the use of large numbers of rich burn engines with NSCR catalysts.

This methodology is already being tested in the Colorado State University research project.

V. Any uncertainty associated with the option

The cost of the ambient monitoring program is not well established because the monitoring technology is not fully specified. Therefore, there is some uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

To be determined.

VII. Cross-over issues to the other source groups

This mitigation option would cross over to the Oil and Gas work group.

RESOLUTIONS

Introduction

In January, 2005 the Cortez/Montezuma League of Women Voters Air Quality Committee began its study of air quality issues in Montezuma County. It became evident that to study air quality we needed facts. To gain facts we needed monitoring. A committee was formed consisting of the following League of Women Voters members: Sylvia Olivia-air quality consultant, Judy Schuenemeyer-lawyer, Eric Janes-water quality expert, Jack Schuenemeyer-statistician, Mary Lou Asbury-spokesperson. The committee met frequently and came up with a plan of action.

We invited Mark Larson, our state representative and Jim Isgar, our state senator, to a League of Women Voters meeting. Sylvia showed the plume model (a computer model of the plume movement from the areas existing power plants and the proposed 2 new power plants). We discussed the need for monitoring in the Montezuma Valley. Both agreed to take our concerns to the Colorado Legislature and the Colorado Health Department. The ground work was laid.

The committee then met in Durango with the Congressional staff of Senator Ken Salazar and Representative John Salazar. To show governmental and community support for air monitoring we decided we needed to take resolutions to the Montezuma County Commissioners, Cortez City Council, and Mancos and Dolores Town Boards. A power point presentation with facts on ozone and mercury was decided upon.

The committee met over a period of 2-3 months to put the finishing touches on the power point, commentary and resolutions. Presentations were scheduled starting in June,2005.

Sylvia Olivia, Eric Janes, Judy and Jack Scheunemeyer and Mary Lou Asbury were in attendance for all presentations. Questions were answered to the satisfaction of all. Resolutions were signed in support of getting air monitoring, data collection and analysis from the EPA, BLM-CO, BLM-NM, and USGS. These have been mailed to all interested parties including all the Colorado Congressional Delegation and to our state representative and senator. The need was recognized, but the funding has been problematic.

The committee has continued to do presentations to various groups to gain support for the need for air monitoring in the Montezuma Valley. The need becomes more critical as final plans are being made to construct a new power plant. Also, more coal bed methane wells are proposed in the San Juan Basin and throughout the Four Corners Region.

There are many health issues and lifestyle concerns which require an air quality monitoring system. The League of Women Voters resolutions help show concern from representative government. The resolutions follow from the Montezuma County Commissioners, Cortez City Council, Mancos Town Board and Dolores Town Board.

City of Cortez
Resolution No. 17, Series 2005
United States Environmental Protection Agency

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional monitoring sites are needed in the County to measure current levels of air pollution in order to assess the additional impact on air quality of the proposed power plant.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional air quality monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites through Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Montezuma County Commissioners, the EPA, and other parties as they shall deem appropriate to query.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

City of Cortez
Resolution No. 14, Series 2005
USGS Colorado Water Science

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional water monitoring sites on a bi-weekly to monthly frequency are needed on the Dolores River and Mancos River systems in the County to measure levels of mercury in order to assess the ultimate fate of mercury from the proposed power plant and existing power plants.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional water monitoring sites for mercury are needed on the Dolores and Mancos River systems to adequately assess the ultimate fate of mercury from air pollution sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the USGS Colorado Water Science Director in Denver seek funding in the Fiscal Year 2006-2007 budgets for increasing the USGS Colorado ability to monitor mercury in water in the Dolores and Mancos River systems.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

RESOLUTION # 230
TOWN OF DOLORES
SUPPORT FOR AIR AND WATER MONITORING FUNDING THROUGH COLORADO BUREAU OF LAND MANAGEMENT

WHEREAS, The Town of Dolores Board of Trustees, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town; and

WHEREAS, concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico; and

WHEREAS, Sithe Global Power, Inc. of Houston, Texas and the Dine' Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children; and

WHEREAS, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

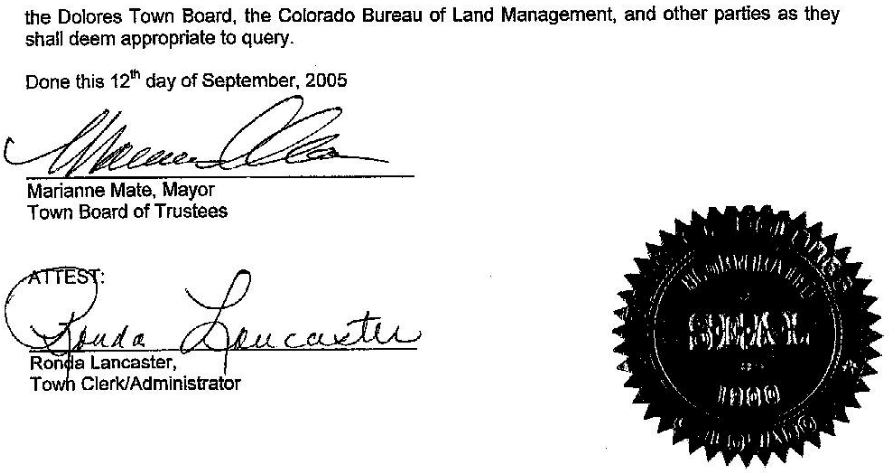
WHEREAS, County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Dolores; and

WHEREAS, additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, and

NOW, THEREFORE BE IT RESOLVED, that the Town Board, Town of Dolores finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents; and

BE IT FURTHER RESOLVED, that the Town Board, Town of Dolores requests that the Colorado Bureau of Land Management see funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites throughout Montezuma County. The Town Board asks that funding be directed to an entity in southwestern Colorado mutually agreeable to



the Dolores Town Board, the Colorado Bureau of Land Management, and other parties as they shall deem appropriate to query.

Done this 12th day of September, 2005

Marianne Mate, Mayor
Town Board of Trustees

ATTEST:

Ronda Lancaster

Ronda Lancaster,
Town Clerk/Administrator

1900

RESOLUTION NO. 2006–40

A RESOLUTION OF THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, FOR REGION IX AIR DIVISION OF THE ENVIRONMENTAL PROTECTION AGENCY CONCERNING THE CLEAN AIR ACT PERMIT FOR THE DESERT ROCK POWER PLANT

WHEREAS, the United States Environmental Protection Agency (US EPA) Region IX has proposed a Clean Air Act permit that would authorize construction of a 1500-megawatt coal-fired power plant on the Navajo Nation; and

WHEREAS, the permit regulates the reduction of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead emissions with the Best Available Control Technology, and must comply with health-based National Ambient Air Quality Standards; and

WHEREAS, Chapter 6, page 6.1 of the La Plata County Comprehensive Plan - Environmental Resources states "La Plata County's natural resources are a valuable community asset. Ensuring their preservation and appropriate use is important to both the natural beauty and economy of La Plata County;" and

WHEREAS, "Environmental Quality and unique natural features are what defines the character of La Plata County and ensuring their continued viability and health is important;" and

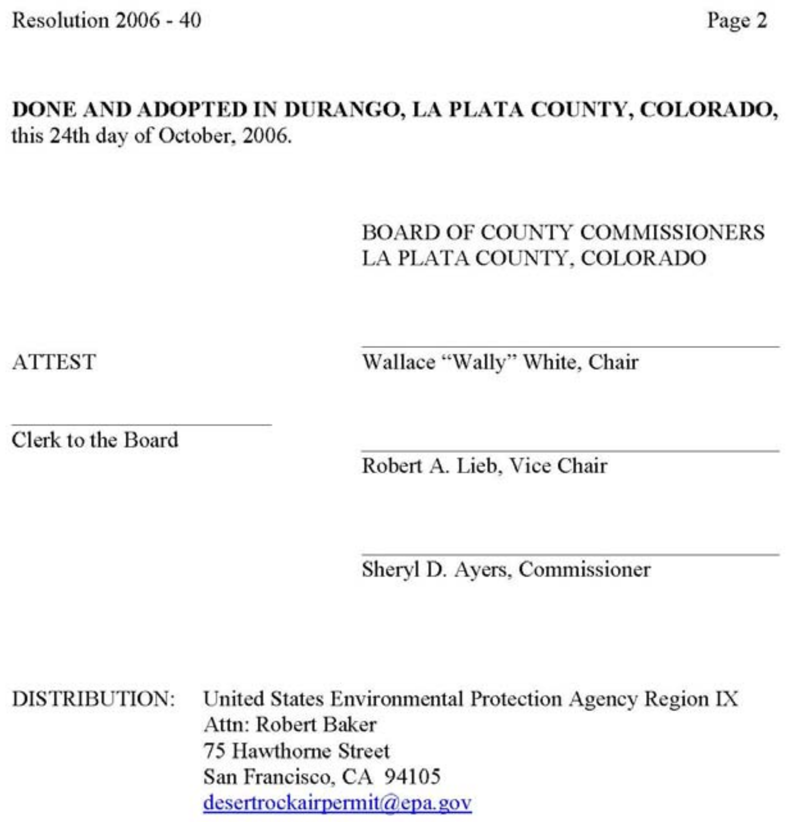
WHEREAS, the comment period for this clean air quality permit closes before the draft Environmental Impact Statement is released to the public resulting in an incomplete understanding of the cumulative impacts of the plant; and

WHEREAS, mercury is a significant and demonstrable problem resulting in a degradation in the quality of life for La Plata County citizens, failure to include the monitoring of mercury, a byproduct of all coal burning power plants would be negligent to the citizens;

NOW THEREFORE, BE IT RESOLVED BY THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, AS FOLLOWS:

1. That the La Plata County Board of County Commissioners hereby requests that the Environmental Protection Agency Region IX Air Division deny the Clean Air Act Permit for Desert Rock Power Plant so the full Environmental Impact Statement for this project is completed to allow the citizens of La Plata County an understanding of the full cumulative impacts from the proposed plant.

2. That the La Plata County Board of County Commissioners hereby requests that all available technology be utilized to reduce the amount of pollutants, including mercury, emitted by this plant.



DONE AND ADOPTED IN DURANGO, LA PLATA COUNTY, COLORADO, this 24th day of October, 2006.

BOARD OF COUNTY COMMISSIONERS
LA PLATA COUNTY, COLORADO

ATTEST

Wallace "Wally" White, Chair

Clerk to the Board

Robert A. Lieb, Vice Chair

Sheryl D. Ayers, Commissioner

DISTRIBUTION:
United States Environmental Protection Agency Region IX
Attn: Robert Baker
75 Hawthorne Street
San Francisco, CA 94105
desertrockairpermit@epa.gov

Resolution (BLM-NM)

Whereas the Board of Trustees, Town of Mancos, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town, and

Whereas concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Mancos, and

Whereas additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, Now Therefore

Be It Resolved, that the Board of Trustees, Town of Mancos finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents, and

Be It Further Resolved, that the Board of Trustees, Town of Mancos requests that the Bureau of Land Management New Mexico State Director, Santa Fe seek funding in the Fiscal Year 2006-2007 budgets for air quality monitoring equipment for ozone to be placed at appropriate sites in Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Board of Trustees, the BLM New Mexico and Colorado State Directors, and to other parties as they shall deem appropriate.

APPROVED THIS 22 DAY of June, 2005

Greg Rath
Greg Rath, Mayor

Michele Black
Michele Black, Mayor Pro-Tem

Perry Lewis

Herman J. Muniz
Herman Muniz

Nick Baumgartner
Nick Baumgartner

Ray Martinez
Ray Martinez

Nicki Elmore
Nicki Elmore

THE BOARD OF COUNTY COMMISSIONERS
OF THE COUNTY OF MONTEZUMA
STATE OF COLORADO

At a regular meeting of the Board of County Commissioners of Montezuma County, Colorado, duly convened and held the 13th day of June, 2005, with the following persons in attendance:

Commissioners:	Dewayne Findley, Gerald Koppenhafer, and Larrie Rule
Commissioners Absent:	
County Administrator:	Thomas J. Weaver
County Attorney:	Bob Slough
Clerk and Recorder:	Carol Tullis

the following proceedings, among others, were taken:

Resolution # 5-2005

Resolution (EPA)

WHEREAS, the Commissioners of Montezuma County Colorado are interested in a healthy environment, clean air and water for citizens of Montezuma County; and

WHEREAS, concerns are being raised by Montezuma County residents about the possible effects on air quality and water by the proposed Desert Rock Energy Project; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County; and

WHEREAS, additional monitoring sites may be needed in the County to measure current levels of ozone, and mercury in order to assess the additional impact of the proposed power plant; and

WHEREAS, the Commissioners of Montezuma County find that additional air and water monitoring sites may be needed elsewhere in the County to adequately assess the impact of air pollution and water contamination,

NOW THEREFORE BE IT RESOLVED THAT the Commissioners request that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding for equipment, operation and data analysis in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment, as Montezuma County assumes no responsibility for the purchase, operation and data analysis of any equipment associated with this resolution, to be placed at sites throughout Montezuma County.

Commissioners voting aye in favor of the resolution were:

H Dewayne Findley Gerald Koppenhafer Larrie D Rule

Commissioners voting nay against the resolution were:

____________ ____________ ____________

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

I certify that the above Resolution is a true and correct copy of same as it appears in the minutes of the Board of County Commissioners of Montezuma County, Colorado and the votes upon same are true and correct.

Dated this 13th day of June, 2005.

1889

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

BUDGETS / FUNDING AND PROJECTED COSTS

Once the task of identifying suitable monitoring site locations has been completed, funding must be obtained to set up and operate the sites.

Capital costs and operating costs of a monitoring site will vary according to what parameters the site is measuring. The following spreadsheets show examples of capital and operating costs of two different monitoring sites.

The Shamrock site is under the jurisdiction of the IMPROVE **(Interagency Monitoring of Protected Visual Environments)** federal program and the Deming site is a state-run SLAMS **(State/Local Air Monitoring Stations)** site.

Funding of these types of sites usually comes from the federal government, but as federal budgets are cut, other resources have to be sought out. States have entered into partnerships with industry in order to fund monitoring activities. Various permit fees can be instituted or increased to obtain funds for monitoring. Private organizations can also be possible sources of funding.

A spreadsheet of possible funding sources is also shown. This spreadsheet lists organizations that are potential sources of funding, the geographic areas supported, applicant requirements, and the highest recent grants awarded. Most of these private funders require that grant recipients be non-profit, 501 (c) (3) organizations. Many of the funders also like projects that are collaborations and creative efforts capable of replication in other areas. They might support joint non-profit/governmental projects.

Shamrock Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price	NOTES
NOX Analyzer	1	10,000.00	10,000.00	
O3 Analyzer	1	0.00	0.00	From other site
NOx Calibration Devices	1	8,000.00	8,000.00	
IMPROVE Aerosol 4 Modules	1	16,000.00	16,000.00	
IMPROVE Housing Installation	1	5,000.00	5,000.00	
Climate Controlled Monitoring Shelter	1	9,000.00	9,000.00	
Data Logger	1	5,000.00	5,000.00	
Installation for Data Logger	1	5,000.00	5,000.00	
Laptop Computer	1	2,500.00	2,500.00	
Meteorology Station	1	4,000.00	4,000.00	
TOTAL			**$64,500.00**	

Shamrock Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price	NOTES
Power and Phone	1	1,000.00	1,000.00	
Data Handling Contract	1	25,000.00	25,000.00	Data handling, digital photography, calibration, and reporting for NOx, Ozone, and Meteorology
IMPROVE Contract Fees	1	33,000.00	33,000.00	Analysis, reporting, and QA/QC
Labor	1	4,000.00	4,000.00	Total annual labor for: Weekly calibration, maintenance, and data downloads
TOTAL			**$63,000.00**	

Deming Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price
Thermo 42i NOX Analyzer	1	6,464.68	6,464.68
Thermo 49i O3 Analyzer	1	4,422.88	4,422.88
R&P TEOM PM10 Analyzer	1	17,500.00	17,500.00
Monitoring Shelter; Morgan Bldg	1	6,000.00	6,000.00
Intake Manifold	1	1,356.00	1,356.00
Sabio Calibrator	1	10,975.00	10,975.00
Sabio Keyboard	1	50.00	50.00
Sabio Zero Air Supply	1	2,447.00	2,447.00
Serial Cable; Sabio to Sabio	1	15.00	15.00
Null Modem Cable; Sabio to Computer	1	15.00	15.00
Solenoid Valves	2	215.00	430.00
Solenoid Valve Driver Cable	1	40.00	40.00
SS "T"'s (1/8" NPT to 1/4" OD)	2	17.60	35.20
SS Elbows (1/8" NPT to 1/4" OD)	4	15.00	60.00
Solenoid Valve Mounting Bracket	1	50.00	50.00
1/4" Teflon Tubing (50 ft)	0.2	350.00	70.00
1/8" Teflon Tubing (50 ft)	0.2	450.00	90.00
1/4" SS Plugs (caps)	4	7.50	30.00
1/8" SS Plugs (caps)	4	5.50	22.00
Glass Funnels	2	15.00	30.00
Surgical Tubing (50 ft)	0.2	40.00	8.00
EPA NO Protocol Gas Standard	1	258.00	258.00
Gas Regulator	1	625.00	625.00
Gas Cylinder Wall Mounting Bracket	1	25.00	25.00
Serial Cables; asst'd lengths, Air Monitors to Computer Moxa Cable	3	15.00	45.00
8-Port Moxa Card	1	300.00	300.00
Moxa Cable; 8 strand	1	55.00	55.00
Campbell Data Logger (CR10x)	1	1,779.00	1,779.00
12v Battery for Data Logger	1	25.00	25.00
Power Adapter for Data Logger	1	10.00	10.00
SC32B Optically Isolated Interface	1	80.00	80.00
APC UPS	1	200.00	200.00

Description	Qty	Unit Price	Total Price
Wireless Modem	1	500.00	500.00
Computer, monitor, keyboard, mouse	1	3,000.00	3,000.00
MET Tower Base; B-14	1	75.00	75.00
MET Tower	1	511.00	511.00
Lightning Rod	1	15.00	15.00
Grounding Rod	1	25.00	25.00
Rod Clamps	2	15.00	30.00
Tower Mast	1	35.00	35.00
Tower Cross Bar	1	35.00	35.00
Hardware Crosses, standard and offset	1	15.00	15.00
Solar Sensor (Li 200 SA 50)w/ Cable	1	215.00	215.00
Solar Sensor Mv Adapter (2220)	1	27.00	27.00
Solar Sensor Mounting Base	1	44.00	44.00
Solar Sensor Mounting Arm	1	65.00	65.00
Wind Monitor Unit (05305-5 AQ)	1	1,200.00	1,200.00
Wind Monitor Cable (50 ft)	1	50.00	50.00
Temperature Probes w/ Cable	2	425.00	850.00
Temperature Probe Aspirator	2	726.00	1,452.00
Power Installation	1	1,500.00	1,500.00
Security Fencing	1	1,600.00	1,600.00
TOTAL			**$ 64,756.76**

Deming Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price
Power:	1	845.00	845.00
Communications:	1	830.00	830.00
Labor:	1	5,285.00	5,285.00
Consumables:	1	1,500.00	1,500.00
TOTAL			**$ 8,460.00**

Possible Funding Sources for Monitoring

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
PRIVATE SOURCES			
Ben & Jerry's Foundation (802) 846-1500 www.benjerry.com/foundation	national	501(c)(3)	$15,000
Patagonia, Inc. (805)643-8616 www.patagoniainc.com	Colorado	501(c)(3)	$20,000
Coutts & Clark Western Foundation (970) 259-6169 thinair@starband.net	SW CO multi-state	501(c)(3)	$5,000
William & Flora Hewlett Foundation (650) 234-4500 www.hewlett.org	national	501(c)(3)	$2,400,000
Microsoft Corp. Rocky Mountain Region (720) 528-1700 sandyp@microsoft.com	Rocky Mountain area	501(c)(3) local govt. entity?	$30,000
Anschutz Family Foundation (303) 293-2338 info@anschutzfamilyfoundation.org	Colorado, especially rural	501(c)(3)	$20,000
Eastman Kodak Charitable Trust (585)724-2434 www.kodak.com/us/en/corp/community.shtml	Colorado	501(c)(3)	$250,000

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
Greenlee Family Foundation (303) 444-0206 directorgff@aol.com	SW CO	501(c)(3)	$10,000
El Pomar Foundation 800-554-7711 grants@elpomar.org	Colorado	501(c)(3)	$1,550,000
Ford Motor Company Fund (313) 845-8711 fordfund@ford.com	National	501(c)(3)	$265,000

ADDITIONAL SOURCES FOR INFORMATION ON PRIVATE FUNDING FOR ENVIRONMENTAL PROJECTS

Environmental Grant Makers Association
(212 812-4260
shansen@ega.org

Community Resource Center, Inc.
(303) 623-1540
www.cramerica.org

SUMMARY OF SUGGESTIONS / PRIORITIES

Introduction

Air pollution is defined as a chemical, physical or biological agent that modifies the natural characteristics of the atmosphere.[1] Pollutants in the air may be natural in origin, such as blowing dust, forest fire smoke or organic compounds from vegetation. Of greater concern are anthropogenic, or man-made pollutants. These include chemicals and particulates from motor vehicles, smoke stacks, incinerators, refineries, industrial degreasing and pesticides, to name just a few. Pollutants may be classified as primary, where they are directly released form a source, or as secondary, where they are formed from reactions of other pollutants in the atmosphere. The health effects caused by air pollutants may range from subtle biochemical and physiological changes to difficulty breathing, wheezing, coughing and aggravation of existing respiratory and cardiac conditions. These effects can result in increased medication use, increased doctor or emergency room visits, more hospital admissions and premature death.[1]

Air pollution has been an issue to human health for centuries. One of the most famous episodes was the “Great Smog” that occurred in London, England in December 1952. Lasting for four days, over 12,000 people died either during the episode or in the months following as a result of the health effects.[2] While not the first air pollution smog to cause deaths, it was the largest to date and led to some of the first Clean Air Acts and air quality regulations in the world. In the United States, the first Clean Air Act was passed in 1963. However, it was not until the Clean Air Act of 1970 and with the creation of the U.S. Environmental Protection Agency (EPA) in the same year that real air pollution control came into full force.[3] This 1970 Clean Air Act was revised and expanded in 1990.

The U.S. EPA has set national ambient air quality standards (NAAQS) for six “criteria” pollutants. These are wide-spread pollutants from numerous and diverse sources that are considered harmful to public health and the environment. There are two types of NAAQS. Primary standards set limits to protect public health, including the health of “sensitive” populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings.[4] The “criteria” pollutants are carbon monoxide, ozone, sulfur dioxide, nitrogen dioxide, lead and particulates (PM_{10} and $PM_{2.5}$). However, there are many other pollutants that can be found in the ambient air. Air toxics, which includes a variety of organic compounds and metals, is an area of increasing concern to human health. Visibility, while not directly a health-related concern, is an aesthetic concern and can be an indicator of other health-related pollutants. The sources and health/environmental impacts vary from pollutant to pollutant, though many are linked to each other.

Carbon monoxide is a colorless and odorless gas formed primarily from incomplete combustion of fuels. It is a product of motor vehicle exhaust, which contributes about 60 percent of all carbon monoxide emissions nationwide. Other sources of carbon monoxide emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires. With increasing emissions controls on motor vehicles and other sources, ambient carbon monoxide levels nationwide have been reduced significantly over the past two decades. Carbon monoxide enters the bloodstream through the lungs and reduces oxygen delivery to the body's organs and tissues. The health threat from carbon monoxide is most serious for those who suffer from cardiovascular disease. Visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, and difficulty in performing complex tasks are all associated with exposure to elevated carbon monoxide levels.[5]

Ozone is a highly reactive gas that is a form of oxygen. Though it occurs naturally in the stratosphere to provide a protective layer high above the earth, at ground-level it is the prime ingredient of smog.[6] Ozone is a secondary pollutant formed by the action of sunlight on carbon-based chemicals known as hydrocarbons, acting in combination with a group of air pollutants called oxides of nitrogen. As a result, ozone is generally a summer afternoon issue. Ozone reacts chemically with internal body tissues that it comes in contact with, such as those in the lung. It also reacts with other materials such as rubber compounds, breaking them down. Health symptoms include shortness of breath, chest pain when inhaling deeply, wheezing and coughing. Research on the effects of prolonged exposures to relatively low levels of ozone have found reductions in lung function, biological evidence of inflammation of the lung lining and respiratory discomfort.[7]

Sulfur dioxide is a gas that is formed when fuel containing sulfur (mainly coal and oil) is burned, and during metal smelting and other industrial processes. The major health concerns associated with exposure to high concentrations of sulfur dioxide include effects on breathing, respiratory illness, alterations in the lungs defenses, and aggravation of existing cardiovascular disease. Asthmatics and individuals with cardiovascular disease or chronic lung disease, as well as children and the elderly are particularly susceptible. In addition, sulfur dioxide is a major precursor to $PM_{2.5}$ particulates and acid rain.[8]

Nitrogen dioxide is a light brown gas that can become an important component of urban haze. Oxides of nitrogen (which includes nitrogen dioxide) usually enter the air as the result of high-temperature combustion processes, such as those occurring in automobiles and power plants. Nitrogen dioxide plays an important role in the atmospheric reactions that generate ozone. Home heaters and gas stoves also produce substantial amounts of nitrogen dioxide. Nitrogen dioxide can irritate the lungs and lower resistance to respiratory infections. Oxides of nitrogen are an important precursor to ozone, $PM_{2.5}$ particulates and acid rain.[9]

Lead is a metal that is used in a wide variety of commercial products. In the past, automotive sources were the major contributor of lead emissions to the atmosphere. As a result of unleaded fuels now being used, ambient lead levels have decreased significantly. Today, metals processing is the major source of lead emissions to the atmosphere. The highest concentrations of lead are found in the vicinity of nonferrous and ferrous smelters, battery manufacturers, and other stationary sources of lead emissions. Exposure to lead occurs mainly through the inhalation of air and the ingestion of lead in food, water, soil, or dust. It accumulates in the blood, bones, and soft tissues. Because it is not readily excreted, lead can also adversely affect the kidneys, liver, nervous system, and other organs. Excessive exposure to lead may cause neurological impairments such as seizures, mental retardation, and/or behavioral disorders. Recent studies also show that lead may be a factor in high blood pressure and subsequent heart disease.[10]

Particle pollution is a mixture of microscopic solids and liquid droplets suspended in the air. This pollution, also known as particulate matter, is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, soil or dust particles, and allergens (such as fragments of pollen or mold spores).[11] Particulate pollution comes from such diverse sources as factory and utility smokestacks, vehicle exhaust, wood burning, mining, construction activity, and agriculture.[12] The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream. Exposure to such particles can affect both your lungs and your heart. Particulate matter air pollution is especially harmful to people with lung disease such as asthma and chronic obstructive pulmonary disease (COPD), which includes chronic bronchitis and emphysema. Exposure to particulate air pollution can trigger asthma attacks and cause wheezing, coughing, and respiratory irritation in individuals with sensitive airways. Larger particles are of less concern, although they can irritate your eyes, nose, and throat.

Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. Examples of toxic air pollutants include benzene, which is found in gasoline; perchlorethlyene, which is emitted from some dry cleaning facilities; and methylene chloride, which is used as a solvent and paint stripper by a number of industries. Examples of other listed air toxics include dioxin, asbestos, toluene, and metals such as cadmium, mercury, chromium, and lead compounds.[13] There are no NAAQS for toxic air pollutants. Instead, they are regulated nationally by requiring the use of pollution controls on sources.

Visibility is defined as the greatest distance at which a black object can be seen and recognized when observed against a background fog or sky. From an aesthetic perspective, visibility represents not just visual range, but rather the overall visual experience of a scene.[14] Thus, visibility issues are not directly a health impact. However, many of the pollutants that cause visibility degradation may cause health impacts. In addition to primary particulates, secondary particulates are a part of visibility degradation. These secondary particulates can be formed from sulfur dioxide and nitrogen dioxide, both of which are criteria pollutants.

Both N and sulfur (S) oxides can form “acid rain” and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems.

Analysis and Interpretation of Existing Data

Meteorology

Meteorological data are collected at a number of different locations in the Four Corners region.

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

Ozone and Precursor Gases

Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as “equivalent’ or “reference” by the U.S. Environmental Protection Agency (EPA) are used.

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS. At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time.

NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad. These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic.

VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.

Mercury

Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River. Atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively.

Nitrogen and Sulfur Compounds

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network.

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado.

Visibility

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE's optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2.

Carbon Monoxide, PM_{10} and Other Common Pollutants

Carbon Monoxide

Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS.

PM_{10}

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System. Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS.

Others

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides.

Suggestions for Future Monitoring Work

Meteorology

No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona. No suggestions for additional monitoring of meteorological parameters are currently being proposed.

Ozone and Precursor Gases

While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

Suggestions for Future Monitoring Work for Ozone:

Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

Mercury

Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Suggestions for Future Monitoring Work for Mercury:

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

4. Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

5. Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

6. Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

Nitrogen and Sulfur Compounds

While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work for Nitrogen and Sulfur Compounds:

Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc.

Visibility

Most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is recommended that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

   D. could be incorporated into existing monitoring sites;
   E. should include photographic documentation;
   F. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

Carbon Monoxide, PM_{10} and Other Common Pollutants

No suggestions for additional monitoring of carbon monoxide, PM10 and other common pollutants are currently being proposed.

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RESPONSES TO "MONITORING" COMMENTS

(by Gordon Pierce)

1. Kandi & David LeMoine, 7/17/2007
"… I reviewed what the monitoring group put together, and I think they did an excellent work."

The workgroup would like to say thanks! (No changes to the report.)

2. BP, 7/13/2007
"While the Draft Report suggestion for addition of new monitoring sites will provide valuable insight to understanding air quality in the region, a detailed analysis of current monitoring data also needs to be conducted to identify trends in air quality. In addition, analyzing trends in monitoring data in conjunction with changes in emissions will provide an important understanding of atmospheric processes. Also, it may be possible to evaluate monitoring data to assist in understanding source receptor relationships.
Confidence limits need to be developed based on monitoring accuracy and precision to determine if observed trends in data are statistically significant or simply random variations in analytic methods. There are also bounding calculations that could be performed that may assist in determining how changes in emissions may change visibility. Such calculations would entail using the IMPROVE data and ratioing the concentrations to calculate the improvement in visibility and establish an upper bound of visibility improvement.
It is recommended that the Task Force conduct a detailed analysis of the IMPROVE monitoring data in the region since BP believes that such an analysis would assist in developing meaningful strategies for improving air quality in the region. BP would welcome the opportunity to assist in establishing a scope of work for such an activity."

(Full response to be written by Sylvia Oliva.) The workgroup agrees that it would be nice to do more with trends analyses, confidence limits and IMPROVE data analyses. However, this was much more work than the workgroup had time to do. (No changes to the report.)

3. Jeanne Hoadley, 7/10/2007
"I would find it helpful if the wind roses on the maps were labeled with the station name."

The workgroup debated extensively as to how much information should be included on the wind rose maps. It was felt that adding more information would make the maps too cluttered and that station names should be presented separately. Thus, maps with only the station names and elevations are presented immediately preceding the wind rose maps. (No changes to the report.)

4. Jeanne Hoadley, 7/10/2007
"Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon."

At the time this subsection was written, there was not a specific date as to exactly when the Navajo Nation would be able to get their new air monitoring site fully operational. In further conversations with the Navajo Nation, the date is still uncertain due to electrical power issues. The report will be revised so that the text reads that the site is planned to commence operation by the end of 2007. (See report for revision under OZONE AND PRECURSOR GASES subsection, "Existing Ozone Data for the Four Corners Region".)

5. Jeanne Hoadley, 7/10/2007
“Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon.
The next sentence has a typo...the "closest" Arizona site.”

Thank you for catching the typo. The word will be revised from “closes” to “closest”. (See report for revision under OZONE AND PRECURSOR GASES subsection, “Existing Ozone Data for the Four Corners Region”.)

6. Mark Jones, 7/10/2007
“Comment on behalf of Roy Paul, "Why is there no ozone monitoring on the Western Slope of Colorado?"”

There are questions as to whether this comment is referring to the southwest/Four Corners area of Colorado or further north, such as around Mesa and Garfield counties in Colorado. For the southwest/Four Corners area, which is the focus of this workgroup, ozone monitoring is currently performed at four locations in Colorado. These locations are shown on the map in the “Ozone and Precursor Gases” subsection of the report. In addition, for recommendation #2 in the subsection, a passive ozone study was performed in the area during August 2007 using monies recently appropriated by the Colorado legislature. A revision to address this is made under recommendation #2. (See report for revision under OZONE AND PRECURSOR GASES subsection, recommendation #2.)

7. Jeanne Hoadley, 7/10/2007
“The pollutants in the header seem to be out of place in this table.”

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

8. Jeanne Hoadley, 7/10/2007
“Again the header in this table is messed up, making it impossible to understand.”

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

9. Jeanne Hoadley, 7/10/2007
“Mercury- Rationale and Benefits. It is not clear to me why Weminuche Wilderness is singled out here...there are many other Class 1 areas in or near this region.”

(Full response to be written by Koren Nydick.) The commenter is correct in that other Class 1 areas are in the region. Weminuche was simply being used as an example. Mercury will be clarified in the report and other Class 1 areas will also be listed or mapped. (See revisions from Koren Nydick.)

Response to BP's Comments

(by Sylvia Oliva)

"Detailed analysis [analyses] of current monitoring data" including trends and back trajectories are already available on the Interagency Monitoring for the Projected Visual Environment, IMPROVE, web site (http://vista.cira.colostate.edu/improve/). Mesa Verde National Park data reaches back to the early 1990s. The highest standard possible for "accuracy and precision" of IMPROVE filters is well-established by the monitoring analysis agency: Crocker Nuclear Labs, University of California at Davis.

IMPROVE filter analyses include x-ray spectroscopy and related techniques. The filters themselves are of several different materials to best trap different aerosols and particulates. (This is why, unfortunately, data availability is traditionally in arrears for 12 to18 months.) Furthermore, any changes in filter composition or analysis protocol through the years are precisely notated in the preamble for accessing raw data for either single or groups of IMPROVE sites, single or groups of parameters.

It indeed would contribute to important understanding of atmospheric processes to take IMPROVE trend data (already available as previously mentioned) with emissions changes to assist in "understanding source-receptor relationship[s]." The caveat, here is that Mesa Verde data is not truly representative of visibility impairment in that the park's physical location (and therefore its IMPROVE site) is really not within the impairment atmosphere, contrary to other parks, e.g. Grand Canyon NP, Yellowstone, NP, or the Great Smokies NP. Rather, the visitor at Mesa Verde sees visibility impairment from outside. Likely, Mesa Verde IMPROVE data might be matched as background with other IMPROVE station data.

So, such a tremendously laudable project correlating trends with emissions sources is not within the present financial means and scope of the current task force.

Dramatic improvements in computer processing power the past two years will quite revolutionize modeling techniques. If these techniques are already incorporated into modeling software, establishing "an upper bound of visibility improvement" may well be a more realistic task than heretofore. (See Marufu, L. T. et al, The 2003 North American electrical blackout: An accidental experiment in atmospheric chemistry, Geophys. Res. Lett., 31, L13106, doi:10.1029/2004GL019771. "The dramatic improvement in air quality during the blackout may result from underestimation of emissions from power plants, inaccurate representation of power plant effluent in emission models or unaccounted for atmospheric chemical reaction(s).")

Appendices

Acronyms

Acronyms

μeq/L	micro-equivalents per liter
μg/L	micrograms per liter
μg/m^3	micrograms per cubic meter
<	less than
>	greater than
°C	degrees Centigrade
°F	degrees Fahrenheit
4CAQTF	Four Corners Air Quality Task Force
AAQS	Ambient Air Quality Standards
AC	Alternating Current
ACI	Activated Carbon Injection
A/F	Air/Fuel
AFR(s)	Air/Fuel Ratio
AFRC(s)	Air/Fuel Ratio Controllers
AFUDC	Allowance For Funds During Construction
aka	also known as
ANGEL	Airborne Natural Gas Emission LIDAR
APCD	Air Pollution Control Division
APD	Application for Permit to Drill
APS	Arizona Public Service
AQI	Air Quality Index
AQRV	Air Quality Related Value
AQS	Air Quality Standard
AQTSD	Air Quality Technical Support Document
ARM	Air Resource Management
ARS	Agricultural Resource Service
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AWMA	Air & Waste Management Association
AZ	Arizona
B&W	Babcock and Wilcox
BACM	Best Available Control Measure
BACT	Best Available Control Technology
BAGI	Backscatter Absorption Gas Imaging
BART	Best Available Retrofit Technology
Bbl/day	barrels per day
Bcf	billion cubic feet
bhp	Brake Horsepower
BHP	BHP Billiton, Ltd.
BLM	Bureau of Land Management (U.S. Department of the Interior)
BMP(s)	Best Management Practices
BTEX	Benzene, Toluene, Ethyl-benzene, Xylene
Btu/kw-hr	British Thermal Units per Kilowatt Hour
CA	California
CAA	Clean Air Act
Ca	Calcium
CaCl	Calcium Chloride
CaCO3	Calcium Carbonate
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CALPUFF	California PUFF Dispersion Model
CaO	Calcium Oxide (Lime)
CARB	California Air Resources Board

CARE	Citizens Against Ruining our Environment
CAS	Chemical Abstracts Service
CASAC	Clean Air Scientific Advisory Committee
CaSO4	Calcium Sulfate
CASTNET	Clean Air Status and Trends Network
CB-DPF	Catalyst-Based Diesel Particulate Filter
CBM	Coal Bed Methane
CBNG	Coalbed Natural Gas
CCAG	Climate Change Advisory Group (New Mexico)
CCC	Colorado Climate Center
CCR	Colorado Code of Regulations
CCS	Carbon Capture and Sequestration
CCV	Closed Crankcase Ventilation
CCX	Chicago Climate Exchange
CDNR	Colorado Department of Natural Resources
CDOT	Colorado Department of Transportation
CDOW	Colorado Division of Wildlife
CDPHE	Colorado Department of Public Health and Environment
CDPHE-APCD	Colorado Department of Public Health and Environment – Air Pollution Control Division
CE	Cumulative Effects
CEC	California Energy Commission
CEDF	Clean Environment Development Facility
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed and/or Coal-fired Boiler
CFLs	Compact Fluorescent Light bulbs
CFR	Code of Federal Regulations
Cfs	Cubic Feet per Second
CGS	Colorado Geological Survey
CH2	Methylene
CH3	Methyl Group
CH4	Methane
CHP	Combined Heat and Power
CI	Compression Ignition
Cl	Chloride
CNG	Compressed Natural Gas
CO	Carbon Monoxide and/or Colorado
CO2	Carbon Dioxide
COA	Conditions of Approval
CoAgMet	Colorado Agricultural Meteorological Network
COBRA	CO-Benefits Risk Assessment
COE	Cost of Energy
COGCC	Colorado Oil and Gas Conservation Commission
COM	Continuous Opacity Monitor
CPANS/ PNWIS	Canadian Prairie and Northern Section/Pacific Northwest International Section
CTG	Control Techniques Guideline
CWCS	Comprehensive Wildlife Conservation Strategy
DC	Direct Current
DCS	Distributed Control System
DEIS	Draft Environmental Impact Statement
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DER	Distributed Energy Resources
DIAL	Differential Absorption LIDAR
DLN	Dry Low NOX

DO	Dissolved Oxygen
DOAS	Differential Optical Absorption Spectroscopy
DOC	Diesel Oxidation Catalyst
DOE	U.S. Department of Energy
DPA	Dinè Power Authority
DREF	Desert Rock Energy Facility
DPF	Diesel Particulate Filter
DR	Demand Response
DRMP	Draft Resource Management Plan
DSIRE	Database of State Incentives for Renewable Energy
DV	Deciview
E	East
E&P	Exploration and Production
EA	Environmental Assessment
EAC	Early Action Compact
EBETS	Economic Incentives-Based Emission Trading System
ECBMR	Enhanced Coal Bed Methane Recovery
ECM	Electronic Control Module
EE	Energy Efficiency
EEREC	Energy Efficiency, Renewable Energy and Conservation
EGR	Exhaust Gas Recirculation
eGRID	Emissions and Generation Integrated Resource Database
EGU	Electric Generating Unit
EIS	Environmental Impact Statement
ENGR	Enhanced Natural Gas Recovery
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
EPD	Environmental Protection Division
EPRI	Electric Power Research Institute
ERMS	Emission Reduction Market System
ESP	Electrostatic Precipitator
ETC	Environmental Technology Council
ETS	Emission Trading System
F	degrees Fahrenheit
F-T	Fischer-Tropsch
FAQs	Frequently Asked Questions
FBC	Fuels Borne Catalyst
FCOTF	Four Corners Ozone Task Force
FCPP	4 Corners Power Plant
FEIS	Final Environmental Impact Statement
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLAG	Federal Land Managers' AQRV Workgroup
FLM	Federal Land Manager
FR	Federal Register
FS	Forest Service (U.S. Department of Agriculture)
Ft	feet
FTF(s)	Flow Through Filter
FY	Fiscal Year
G	gram
g/bhp-hr	grams per brake horsepower-hour
g/hp-hr	grams per horsepower-hour
GF	Growth Fund
GHG(s)	Greenhouse Gases
GIS	Geographic Information System

GOR	Gas Oil Ratio
GVW	Gross Vehicle Weight
GWh/yr	Gigawatt hours per year
H+	Hydrogen ion
H2O	Water
H2S	Hydrogen Sulfide
H2SO4	Sulfuric Acid
HAP(s)	Hazardous Air Pollutants
HC(s)	Hydrocarbons
HF	Hydrogen Fluoride
Hg	Mercury
HCHO	Formaldehyde
HNO3	Nitric Acid
hp	Horsepower
HRSG	Heat Recovery Steam Generator
HRVOC(s)	Highly Reactive Volatile Organic Compounds
I&M	Inspection and Maintenance
IBEMP	Innovation Technology and Best Energy-Environment Management Practices
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
IMPROVE	Interagency Monitoring of Protected Visual Environment
ISA	Instrument Systems and Automation Society
ISCST3	Industrial Source Complex – Short Term Dispersion Model, Version 3
IWAQM	Inter-Agency Work Group on Air Quality Modeling
K	One Thousand Dollars or Potassium
kg/ha-yr	Kilograms per Hectare-Year
km	kilometer
Kwh	kilowatt hour
LAER	Lowest Achievable Emission Rate
lb	pound
lbs/mmBtu	pounds of emissions/million btu heat input
lbs/MWh	pounds of emission/Megawatt-hour
LDAR	Leak Detection and Repair
LEED	Leadership in Energy Efficiency and Design
LiCl	Lithium Chloride
LIDAR	Light Detection and Ranging
LLC	Limited Liability Company
LNC	Lean NOX Catalyst
LNG	Liquefied Natural Gas
LoTOx	Low Temperature Oxidation Technology
LP	Limited Partnership
LPG	Liquefied Petroleum Gas
LTO	Low Temperature Oxidation
LWV	League of Women Voters
MACT	Maximum Achievable Control Technology
MC	Multi-Contact
mcf	one thousand cubic feet
MDN	Mercury Deposition Network
Mg	Magnesium
mg/L	milligrams per liter
mg/m3	micrograms per cubic meter
microg/g	micrograms per gram
MIT	Massachusetts Institute of Technology
MM	One Million Dollars
Mm^{-1}	Inverse Megameters
mmBtu	One Million British Thermal Units

MMcf/day	million cubic feet per day
MMscf/day	million standard cubic feet per day
MMV	Measurement, Monitoring and Verification Techniques
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
mph	Miles Per Hour
MPO	Metropolitan Planning Organization
MSI	Mountain Studies Institute
MW	Megawatt
N	Nitrogen
N2	Nitrogen gas
N2O	Nitrous Oxide
N2O3	Nitrogen Oxide
N2O5	Nitric Pentoxide
NA	Not Applicable
Na	Sodium
NAAQS	National Ambient Air Quality Standard
NADP	National Atmospheric Deposition Program
NEG	Net Excess Generation
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGL	natural gas liquids
NH3	Ammonia
NI	no information
NM	New Mexico
NMED-AQB	New Mexico Environment Department-Air Quality Bureau
NMEMNRD	New Mexico Energy, Minerals and Natural Resources Department
NMHC	Non-Methane Hydrocarbon
NMOC	Non-Methane Organic Compounds
NMOCD	New Mexico Oil Conservation Division
NMOG	Non-Methane Organic Gas
NMOGA	New Mexico Oil and Gas Association
NMRPC	New Mexico Public Regulation Commission
NMUSA	New Mexico Utility Shareholders Alliance
NNEPA	Navajo Nation Environmental Protection Agency
No.	Number
NO	Nitric Oxide
NO2	Nitrogen Dioxide
NO3	Nitrate
NOx	Nitrogen Oxides
NOx/mmBtu	Nitrogen Oxides per million British Thermal Units
NOAA	National Oceanic & Atmospheric Administration
NP	National Park
NPS	National Park Service
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
NTN	National Trends Network
NW	Northwest
NWS	National Weather Service
NYCRR	New York Codes, Rules and Regulations
O&M	Operation and Maintenance
O2	Oxygen

O_3	Ozone
OCD	Oil Conservation Division
OCV	Open Crankcase Ventilation
OECA	Office of Enforcement and Compliance Assurance
OH	Hydroxide
ONG	Onshore Natural Gas
OP-FTIR	Open-Path Fourier Transform Infrared
Oz	Ounce
PAH(s)	Polycyclic Aromatic Hydrocarbon
PC	Pulverized Coal
P/H	Power to Heat Ratio
pH	Acidity Measurement Unit
PLC	Programmable Logic Controller
PM	Particulate Matter
PM_{10}	Particulate Matter (effective diameter < 10 micrograms)
$PM_{2.5}$	Fine Particulate Matter (effective diameter < 2.5 micrograms)
POWID	Power Industry Division
ppb	parts per billion
ppm	parts per million
PRO	Partner Reported Opportunities
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSNM	Public Service of New Mexico
PV	Photovoltaic
QA	Quality Assurance
QC	Quality Control
R&D	Research and Development
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RAWS	Remote Automated Weather Stations
RC&D	Resource Conservation and Development
RE	Renewable Energy
REC(s)	Renewable Energy Credit
RH	Relative Humidity
RIA	Regulatory Impact Analyses
RICE	Reciprocating Internal Combustion Engine
RMP	Resource Management Plan
RMPPA	Resource Management Plan Planning Area
ROD	Record of Decision
ROG	Reactive Organic Gas
ROI	Return on Investment
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standards
RRC	Rebecca Reynolds Consulting
RVP	Reid Vapor Pressure
S	Sulfur
SAR	Specific Absorption Rate
scfh	standard cubic feet per hour of gas flow
SC	Supercritical
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SEP(s)	Supplemental Energy Payment
SI	Spark-Ignition Engine
SIP	State Implementation Plan

SJ	San Juan
SJGS	San Juan Generating Station
SLAMS	State/Local Air Monitoring Stations
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SO2/mmBtu	Sulfur Dioxide/one million British Thermal Units
SOTA	State of the Art
SOx	Sulfur Oxides
SPMS	Special Purpose Monitoring Stations
sq mi	Square Miles
SRI	Southern Research Institute
SRP	Salt River Project Agricultural Improvement and Power District
SUIT	Southern Ute Indian Tribe
SW	Southwest
SWD	Salt Water Disposal Well
SWEEP	Southwest Energy Efficiency Project
TAG	Technical Assessment Guide
TBD	To Be Determined
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TDS	Total Dissolved Solids
TEG	Triethylene Glycol
TF	Task Force
THC	Total Hydrocarbons
TPH	Total Petroleum Hydrocarbons
tpy	tons per year
TSD	technical support document
U.S.C.	United States Code
ULSD	Ultra Low Sulfur Diesel
US	United States
USC	Ultra Supercritical Coal
USCPC	Ultra-Supercritical Pulverized Coal
USDA	U.S. Department of Agriculture
USDI	U.S. Department of the Interior
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
UST	Underground Storage Tank
UT	Utah
VISTAS	Voluntary Innovative Strategies for Today's Air Standards Program
VLUA	Vallecito Land Use Association
VMT	Vehicle Miles Traveled
VOC(s)	Volatile Organic Compounds
VRM	Visual Resource Management
VRP	Visibility Reducing Particles
VRU	Vapor Recovery Unit
vs.	Versus
W	West
W/m2	Watts per square meter
W/O	without
WDEQ	Wyoming Department of Environmental Quality
WESTAR	Western States Air Resource Council
WRAP	Western Regional Air Partnership

Definitions

Definitions

3-way catalyst: A catalyst containing both reduction and oxidation catalyst materials that converts Oxides of Nitrogen (NO_X), Carbon Monoxide (CO), and Non-Methane Hydrocarbons (NMHCs) to Nitrogen (N_2), Carbon Dioxide (CO_2), and water H_2O.

AP-42: An U.S. EPA compendium of emission factors for different source types. An emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). For additional information, see EPA's website at http://www.epa.gov/ttn/chief/ap42/.

Absorption: The process by which the energy of a photon is taken up by another entity.

Acid Deposition: A comprehensive term for the various ways acidic compounds precipitate from the atmosphere and deposit onto surfaces. It can include: 1) wet deposition by means of acid rain, fog, and snow; and 2) dry deposition of acidic particles (aerosols).

Acid Rain: Rain which is especially acidic (pH <5.2). Principal components of acid rain typically include nitric and sulfuric acid. These may be formed by the combination of nitrogen and sulfur oxides with water vapor in the atmosphere.

Acid Rain Program: The overall goal of the Acid Rain Program is to achieve significant environmental and public health benefits through reductions in emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx)—the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Activated Carbon Injection (ACI) Technology: In ACI technology, powdered activated carbon (PAC) sorbent is injected into the flue gas at a location in the duct preceding the particulate matter (PM) control device, which usually is an electrostatic precipitator or a fabric filter. The PAC sorbent binds with the mercury in the flue gas in the duct and in the PM control device. Subsequently, the mercury-containing PAC is captured in the PM control device.
Carbon Capture and Sequestration (CCS): Carbon capture and storage is an approach to mitigating climate change by capturing carbon dioxide (CO2) from large point sources such as power plants and subsequently storing it away safely instead of releasing it into the atmosphere. Technology for capturing of CO2 is already commercially available for large CO2 emitters, such as power plants. Storage of CO2, on the other hand, is a relatively untried concept and as yet (2007) no power plant operates with a full carbon capture and storage system. Currently, the United States government has approved the construction of the world's first CCS power plant, FutureGen, while BP has indicated that it intends to develop a 350 MW carbon capture and storage plant in Scotland, in which the carbon from a natural gas fired generator plant will be stripped out and pumped into the Miller field in the North Sea.

Add-On Control Device: An air pollution control device such as carbon absorber or incinerator that reduces the pollution in exhaust gas. The control device usually does not affect the process being controlled and thus is "add-on" technology, as opposed to a scheme to control pollution through altering the basic process itself. See also pollution prevention.

Adsorber: An emissions control device that removes volatile organic compounds (VOCs) from a gas stream as a result of the gas attaching (adsorbing) onto a solid matrix such as activated carbon.

Adsorption (Physical and Chemical): capability of all solid substances to attract to their surfaces molecules of gases or solutions with which they are in contact. Solids that are used to adsorb gases or dissolved substances are called adsorbents; the adsorbed molecules are usually referred to collectively as the adsorbate. An example of an excellent adsorbent is the charcoal used in gas mask.

Adverse Health Effect: A health effect from exposure to air contaminants that may range from relatively mild temporary conditions, such as eye or throat irritation, shortness of breath, or headaches to permanent and serious conditions, such as birth defects, cancer or damage to lungs, nerves, liver, heart, or other organs.

Aerosol: Particles of solid or liquid matter that can remain suspended in air from a few minutes to many months depending on the particle size and weight.

Afterburner: An air pollution abatement device that removes undesirable organic gases through incineration.

Agricultural Burning: The intentional use of fire for vegetation management in areas such as agricultural fields, orchards, rangelands, and forests.

Air: So called "pure" air is a mixture of gases containing about 78 percent nitrogen; 21 percent oxygen; less than 1 percent of carbon dioxide, argon, and other gases; and varying amounts of water vapor. See also ambient air.

Air Monitoring: Sampling for and measuring of pollutants present in the atmosphere.

Air Pollutants: Amounts of foreign and/or natural substances occurring in the atmosphere that may result in adverse effects to humans, animals, vegetation, and/or materials. (See also air pollution.)

Air Pollution: Degradation of air quality resulting from unwanted chemicals or other materials occurring in the air. (See also air pollutants.)

Air Quality Index (AQI): A numerical index used for reporting severity of air pollution levels to the public. The AQI incorporates five criteria pollutants -- ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide -- into a single index. The new index also incorporates the 8-hour ozone standard and the 24-hour $PM_{2.5}$ standard into the index calculation. AQI levels range from 0 (Good air quality) to 500 (Hazardous air quality). The higher the index, the higher the level of pollutants and the greater the likelihood of health effects. The AQI incorporates an additional index category -- unhealthy for sensitive groups -- that ranges from 101 to 150. In addition, the AQI comes with more detailed cautions.

Air Quality Model: A mathematical relationship between emissions and air quality which simulates on a computer the transport, dispersion, and transformation of compounds emitted into the air.

Air Quality Standard (AQS): The prescribed level of a pollutant in the outside air that should not be exceeded during a specific time period to protect public health. Established by both federal and state governments. (See also ambient air quality standards.)

Air separation membranes: Change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content.

Airshed: Denotes a geographical area that shares the same air because of topography, meteorology, and climate.

Air to Fuel Ratio Controller (AFRC): Device using a closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air Toxics: A generic term referring to a harmful chemical or group of chemicals in the air. Substances that are especially harmful to health, such as those considered under U.S. EPA's hazardous air pollutant program, are considered to be air toxics. Technically, any compound that is in the air and has the potential to produce adverse health effects is an air toxic.

Alcohol Fuels: Alcohol can be blended with gasoline for use as transportation fuel. It may be produced from a wide variety of organic feedstock. The common alcohol fuels are methanol and ethanol. Methanol may be produced from coal, natural gas, wood and organic waste. Ethanol is commonly made from agricultural plants, primarily corn, containing sugar.

Alkane: Chemical compounds that consist only of the elements carbon (C) and hydrogen (H) (i.e. hydrocarbons), where each of these atoms are linked together exclusively by single bonds.

Alternative Fuels: Fuels such as methanol, ethanol, natural gas, and liquid petroleum gas that are cleaner burning and help to meet mobile and stationary emission standards. These fuels may be used in place of less clean fuels for powering motor vehicles.

Ambient Air: The air occurring at a particular time and place outside of structures. Often used interchangeably with "outdoor air." (See also air.)

Ambient Air Quality Standards (AAQS): Health- and welfare-based standards for outdoor air which identify the maximum acceptable average concentrations of air pollutants during a specified period of time. (See also NAAQS and Criteria Air Pollutant.)

American Society for Testing and Materials (ASTM): A nonprofit organization that provides a forum for producers, consumers, and representatives of government and industry, to write laboratory test standards for materials, products, systems, and services. ASTM publishes standard test methods, specifications, practices, guides, classifications, and terminology.

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process.

Ammonia (NH_3): A pungent colorless gaseous compound of nitrogen and hydrogen that is very soluble in water and can easily be condensed into a liquid by cold and pressure. Ammonia reacts with NOx to form ammonium nitrate -- a major $PM_{2.5}$ component in the Western United States.

Ammonia slip: Ammonia emissions from SCR systems.

Area Sources: Those sources for which a methodology is used to estimate emissions. This can include area-wide, mobile and natural sources, and also groups of stationary sources (such as dry cleaners and gas stations). Sources which are not reported as individual point sources are included as area sources. The federal air toxics program defines a source that emits less than 10 tons per year of a single hazardous air pollutant (HAP) or 25 tons per year of all HAPs as an area source.

Aromatic compounds: An organic chemical compound that contains aromatic rings (arenes) like benzene, pyridine, or indole and possessing an aroma, fragrance, flavor, smell, or odor

Asthma: A chronic inflammatory disorder of the lungs characterized by wheezing, breathlessness, chest tightness, and cough.

Atmosphere: The gaseous mass or envelope of air surrounding the Earth. From ground-level up, the atmosphere is further subdivided into the troposphere, stratosphere, mesosphere, and the thermosphere.

Attainment Area: A geographical area identified to have air quality as good as, or better than, the national ambient air quality standards (NAAQS). An area may be an attainment area for one pollutant and a nonattainment area for others.

Baghouse: An air pollution control device that traps particulates by forcing gas streams through large permeable bags usually made of glass fibers.

Banking: A provision used in emissions trading programs that allows a facility to accumulate credits for reducing emissions beyond regulatory limits (emission reduction credits) and then use or sell those credits at a later date.

Baseline: A starting point or condition against which future changes are measured. For air quality emissions, the known emissions in a given year that future emissions can be measured against.

Benzene, Toluene, Ethyl Benzene, Xylene (BTEX): Group of volatile organic compounds (VOCs) found in petroleum hydrocarbons, such as gasoline, and other common environmental contaminants.

Best Available Control Measure (BACM): A term used to describe the "best" measures (according to U.S. EPA guidance) for controlling small or dispersed sources of particulate matter and other emissions from sources such as roadway dust, woodstoves, and open burning.

Best Available Control Technology (BACT): The most up-to-date methods, systems, techniques, and production processes available to achieve the greatest feasible emission reductions for given regulated air pollutants and processes. BACT is a requirement of NSR (New Source Review) and PSD (Prevention of Significant Deterioration).

Best Available Retrofit Technology (BART): An air emission limitation that applies to existing sources and is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source. (See also Best Available Control Technology.)

Bioenergy: Useful, renewable energy produced from organic matter, which may either be used directly as a fuel or processed into liquids and gases.

Biofuels: Liquid fuels and blending components produced from biomass (plant) feedstocks, used primarily for transportation.

Biogenic Source: Biological sources such as plants and animals that emit air pollutants such as volatile organic compounds. Examples of biogenic sources include animal management operations, and oak and pine tree forests. (See also natural sources.)

Biomass: Organic nonfossil matter of a biological origin available on a renewable basis. Biomass includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. A device where heat converts water to steam.

Carbon (CO2) Capture and Storage: CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001). Sometimes referred to as sequestration.

Carbon Dioxide (CO_2): A colorless, odorless gas that occurs naturally in the Earth's atmosphere. Significant quantities are also emitted into the air by fossil fuel combustion.

Carbon mass balance: An accounting of material entering and leaving a system.

Carbon Monoxide (CO): A colorless, odorless gas resulting from the incomplete combustion of hydrocarbon fuels. CO interferes with the blood's ability to carry oxygen to the body's tissues and results in numerous adverse health effects. CO is a criteria air pollutant.

Carcinogen: A cancer-causing substance. (See also cancer.)

CAS Registry Number: The Chemical Abstracts Service Registry Number (CAS) is a numeric designation assigned by the American Chemical Society's Chemical Abstract Service and uniquely identifies a specific compound. This entry allows one to conclusively identify a material regardless of the name or naming system used.

Catalyst: A substance that can increase or decrease the rate of a chemical reaction between the other chemical species without being consumed in the process.

Catalyst Deactivation: Poisoning is a primary factor in deactivation, with blockage and physical destruction of equal importance to catalyst life. When the surface or pores of the catalyst are blocked, flue gas/NOx cannot contact the catalyst.

Catalytic converter: The mechanism by which the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

Cation: A positively-charged ion, which has fewer electrons than protons. An ion is an atom or group of atoms which have lost or gained one or more electrons, making them negatively or positively charged.

Cell Burner: Cell burner boiler means a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Cell burner boilers have closely spaced clusters of two or three burners (i.e., cells) that together result in a single flame. In addition, the boilers are, like many wall-fired boilers, relatively compactly designed with small furnaces.

Chromatography: A set of laboratory techniques for separation of mixtures. One such procedure includes passing a mixture dissolved in a "mobile phase" through a stationary phase, which separates the analyte to be measured from other molecules in the mixture and allows it to be isolated.

Chronic Exposure: Long-term exposure, usually lasting one year to a lifetime.

Chronic Health Effect: A health effect that occurs over a relatively long period of time (e.g., months or years). (See also acute health effect.)

Class I Area: Under the Clean Air Act, a Class I area is one in which visibility is protected more stringently than under the national ambient air quality standards; includes national parks, wilderness area, monuments and other areas of special national and cultural significance.

Clean Air Act (CAA): A federal law passed in 1970 and amended in 1974, 1977 and 1990 which forms the basis for the national air pollution control effort. Basic elements of the act include national ambient air quality standards for major air pollutants, mobile and stationary control measures, air toxics standards, acid rain control measures, and enforcement provisions.

Clean Air Mercury Rule: On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time ever. This rule makes the United States the first country in the world to regulate mercury emissions from utilities.

Cleaner-Burning Gasoline: Gasoline fuel that results in reduced emissions of carbon monoxide, nitrogen oxides, reactive organic gases, and particulate matter, in addition to toxic substances such as benzene and 1,3-butadiene.

Coal bed methane (CBM): Methane found in coal seams.

Code of Federal Regulations (CFR): The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government pursuant to authority derived from the Clean Air, Water, and other environmental acts.

Cogeneration: See combined heat and power.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. Such designs increase the efficiency of the electric generating unit.

Combined Heat and Power (CHP) Plant: A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Combustion: The act or instance of burning some type of fuel such as gasoline to produce energy. Combustion is typically the process that powers automobile engines, oil and gas-field engines, and power plant generators.

Compressed natural gas (CNG): A substitute for gasoline (petrol) or diesel fuel, made by compressing methane extracted from natural gas.

Concentrator: A reflective or refractive device that focuses incident insolation onto an area smaller than the reflective or refractive surface, resulting in increased insolation at the point of focus.
Conventional hydroelectric (hydropower) plant: A plant in which all of the power is produced from natural streamflow as regulated by available storage.

Condensate tank: Tank for storing condensate from oil and gas activity.

Condensate Tank Battery: Comprised of a single storage tank or a group of storage tanks with a design capacity less than or equal to 10,000 barrels per tank, used for the storage of condensate and located at an exploration and production facility.

Consent Decree: When a court case has been filed, the parties can resolve the case short of having a trial by entering into a joint agreement or by consenting to a judgment.

Continuous Emission Monitor (CEM): A type of air emission monitoring system installed to operate continuously inside of a smokestack or other emission source.

Continuous Sampling Device: An air analyzer that measures air quality components continuously. (See also Integrated Sampling Device.)

Control Techniques Guidelines (CTG): Guidance documents issued by U.S. EPA that define reasonably available control technology (RACT) to be applied to existing facilities that emit excessive quantities of air pollutants; they contain information both on the economic and technological feasibility of available techniques.

Cost-Effectiveness: The cost of an emission control measure assessed in terms of dollars-per-pound, or dollars-per-ton, of air emissions reduced.

Criteria Air Pollutant: An air pollutant for which acceptable levels of exposure can be determined and for which an ambient air quality standard has been set. Examples include: ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and PM_{10} and $PM_{2.5}$. The term "criteria air pollutants" derives from the requirement that the U.S. EPA must describe the characteristics and potential health and welfare effects of these pollutants. The U.S. EPA periodically reviews new scientific data and may propose revisions to the standards as a result.

Cryogenic: production of very low temperatures and the behavior of materials at those temperatures below -150C.

Cyclone: An air pollution control device that removes larger particles -- generally greater than one micron -- from an air stream through centrifugal force.

Deciview: A measurement of visibility. One deciview represents the minimal perceptible change in visibility to the human eye.

Desiccant dehydrator: Device that uses moisture-absorbing salts to remove water from natural gas. In general, there are only minor air emissions from desiccant systems.

Diesel Engine: A type of internal combustion engine that uses low-volatility petroleum fuel and fuel injectors and initiates combustion using compression ignition (as opposed to spark ignition that is used with gasoline engines).

Diesel fuel emulsion: Emulsion of diesel and other fuel intended to reduce peak engine combustion temperatures and increase fuel atomization and combustion efficiency.

Diesel oxidation catalyst (DOC): Device that uses a chemical process to break down pollutants in the exhaust stream into less harmful components. Diesel oxidation catalysts can reduce emissions of particulate matter (PM) by 20% and hydrocarbons (HC) by 50% and carbon monoxide (CO) by approximately 40%.

Diesel particulate filter: Filter that collects or traps particulate matter (PM) in the exhaust.

Diffraction: Diffraction refers to various phenomena associated with wave propagation, such as the bending, spreading and interference of waves such as visible light.

Dispersion Model: See air quality model above.

Distributed Generation (Distributed Energy Resources): Refers to electricity provided by small, modular power generators (typically ranging in capacity from a few kilowatts to 50 megawatts) located at or near customer demand.

Dose: The amount of a pollutant that is absorbed. A level of exposure which is a function of a pollutant's concentration, the length of time a subject is exposed, and the amount of the pollutant that is absorbed. The concentration of the pollutant and the length of time that the subject is exposed to that pollutant determine dose.

Dose-Response: The relationship between the dose of a pollutant and the response (or effect) it produces on a biological system.

Drill rig: General term used to describe a wide variety of machines that create holes (usually called boreholes) and/or shafts in the ground, or to install wells.

Dry-bottom, Wall-fired: Dry bottom means the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid. Wall-fired boiler means a boiler that has pulverized coal burners arranged on the walls of the furnace. The burners have discrete, individual flames that extend perpendicularly into the furnace area.

Dry Cooled Coal-Fired: Dry cooling operates without evaporation by passing the steam from the turbines through a set of finned pipes immediately beside the turbine and cooling the water by having large volumes of air driven by fans to condense the steam in the pipes.

Dust: Solid particulate matter that can become airborne.

Ecosystem: A self-sustaining association of plants, animals, and the physical environment in which they live.

Electric Generating Unit (EGU) – Clean Air Interstate Rule definition:
(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of

the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included.

Electrostatic Precipitator (ESP): An air pollution control device that removes particulate matter from an air stream by imparting an electrical charge to the particles for mechanical collection at an electrode.

Emission Factor: For stationary sources, the relationship between the amount of pollution produced and the amount of raw material processed or burned. For mobile sources, the relationship between the amount of pollution produced and the number of vehicle miles traveled. By using the emission factor of a pollutant and specific data regarding quantities of materials used by a given source, it is possible to compute emissions for the source. This approach is used in preparing an emissions inventory.

Emission Inventory: An estimate of the amount of pollutants emitted into the atmosphere from major mobile, stationary, area-wide, and natural source categories over a specific period of time such as a day or a year.

Emission Rate: The weight of a pollutant emitted per unit of time (e.g., tons / year).

Emission Standard: The maximum amount of a pollutant that is allowed to be discharged from a polluting source such as an automobile or smoke stack.

Emission trading system (ETS): Program wherein the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates.

Enardo valve: Brand name for a pressure relief valve installed on condensate and other oil storage tanks to control evaporation and fugitive emission losses that result from flammable and hazardous petroleum vapor-producing products.

Energy Content: The amount of energy available for doing work. For example, the amount of energy in fuel available for powering a motor vehicle.

Energy Crops: Crops grown specifically for their fuel value. These include food crops such as corn and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops are under development: short - rotation woody crops, which are fast - growing hardwood trees harvested in five to eight years, and herbaceous energy crops, such as perennial grasses, which are harvested annually after taking two to three years to reach full productivity.

Energy Efficiency: Energy efficiency refers to products or systems using less energy to do the same or better job than conventional products or systems. Energy efficiency saves energy, saves money on utility bills, and helps protect the environment by reducing the amount of electricity that needs to be generated. When buying or replacing products or appliances for your home, look for the ENERGY STAR® label — the national symbol for energy efficiency. For more information on ENERGY STAR® labeled products, visit the ENERGY STAR® Web site.

Enhanced Gas Recovery and/or Enhanced Coal Bed Methane Recovery: To enhance coal bed methane recovery factors and production rates as a result of CO2 injection.
Burlington Resources has successfully injected CO2 into relatively high permeability coalbeds in the San Juan basin in the USA for several years. They are stimulating coalbed methane production and recovery. The injected CO2 is

adsorbed into the coal matrix and remains in the ground after completion of gas production. However, further testing and demonstration are needed to apply this process to low permeability reservoirs.

Enhanced Oil Recovery: Using CO_2 injection to enhance production from oil reservoirs.

Environmental Justice: The fair treatment of people of all races and incomes with respect to development, implementation, and enforcement of environmental laws, regulations, and policies.

EPA's Natural Gas STAR Program: The Natural Gas STAR Program is a flexible, voluntary partnership between U.S. EPA and the oil and natural gas industry. Through the program, U.S. EPA works with companies that produce, process, and transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potent greenhouse gas.

Ethanol (also known as Ethyl Alcohol or Grain Alcohol, CH3-CH2OH): A clear, colorless flammable oxygenated hydrocarbon with a boiling point of 173.5 degrees Fahrenheit in the anhydrous state. However it readily forms a binary azetrope with water, with a boiling point of 172.67 degrees Fahrenheit at a composition of 95.57 percent by weight ethanol. It is used in the United States as a gasoline octane enhancer and oxygenate (maximum 10 percent concentration). Ethanol can be used in higher concentrations (E85) in vehicles designed for its use. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. The lower heating value, equal to 76,000 Btu per gallon, is assumed for estimates in this report.

Evacuated Tube: In a solar thermal collector, an absorber tube, which is contained in an evacuated glass cylinder, through which collector fluids flows.

Evaporative Emissions: Emissions from evaporating gasoline, which can occur during vehicle refueling, vehicle operation, and even when the vehicle is parked. Evaporative emissions can account for two-thirds of the hydrocarbon emissions from gasoline-fueled vehicles on hot summer days.

Exhaust Gas Recirculation (EGR): An emission control method that involves recirculating exhaust gases from an engine back into the intake and combustion chambers. This lowers combustion temperatures and reduces NOx. (See also nitrogen oxides.)

Exceedance: A measured level of an air pollutant higher than the national or state ambient air quality standards. (See also NAAQS.)

Federal Implementation Plan (FIP): In the absence of an approved State Implementation Plan (SIP), a plan prepared by the U.S. EPA which provides measures that areas must take to meet the requirements of the Federal Clean Air Act.

Feedstock: The raw material that is required for some industrial process.

Flaring: Technique of igniting hydrocarbon gases to convert natural gas constituents (hydrocarbons, including BTEX and other Hazardous Air Pollutants) into less hazardous and atmospherically reactive compounds.

Flash emissions: Emissions resulting by a reduction in pressure and/or temperature when hydrocarbon liquids are dumped into the storage tank from the production separator.

Flow through filters (FTF): Filters for capture or oxidize particles, using a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil.

Flue gas: Exhaust gases following combustion.

Fly Ash: Air-borne solid particles that result from the burning of coal and other solid fuel.

Fossil Fuels: Fuels such as coal, oil, and natural gas; so-called because they are the remains of ancient plant and animal life.

Fugitive Dust: Dust particles that are introduced into the air through certain activities such as soil cultivation, or vehicles operating on open fields or dirt roadways. A subset of fugitive emissions.

Fugitive Emissions: Emissions not caught by a capture system which are often due to equipment leaks, evaporative processes and windblown disturbances.

Furnace: A combustion chamber; an enclosed structure in which fuel is burned to heat air or material.

FutureGen: FutureGen is a project of the US government to build a near zero-emissions coal-fueled power plant that intends to produce hydrogen and electricity while using carbon capture and storage.

Gas Turbine: An engine that uses a compressor to draw air into the engine and compress it. Fuel is added to the air and combusted in a combustor. Hot combustion gases exiting the engine turn a turbine which also turns the compressor. The engine's power output can be delivered from the compressor or turbine side of the engine.

Gasifier: A device for converting solid fuel into gaseous fuel.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Global Warming: An increase in the temperature of the Earth's troposphere. Global warming has occurred in the past as a result of natural influences, but the term is most often used to refer to the warming predicted by computer models to occur as a result of increased emissions of greenhouse gases.

GLYCALC: A software program for estimating air emissions from glycol units using triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

Glycol dehydrator: Any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water from the natural gas stream.

Green Power: Electricity that is generated from renewable energy sources is often referred to as “green power.” Green power products can include electricity generated exclusively from renewable resources or, more frequently, electricity produced from a combination of fossil and renewable resources. Also known as “blended” products, these products typically have lower prices than 100 percent renewable products. Customers who take advantage of these options usually pay a premium for having some or all of their electricity produced from renewable resources. To find out more about green power, visit EPA’s Green Power Partnership Web site.

Greenhouse Effect: The warming effect of the Earth's atmosphere. Light energy from the sun which passes through the Earth's atmosphere is absorbed by the Earth's surface and re-radiated into the atmosphere as heat energy. The heat energy is then trapped by the atmosphere, creating a situation similar to that which occurs in a car with its windows rolled up. A number of scientists believe that the emission of CO_2 and other gases into the atmosphere may increase the greenhouse effect and contribute to global warming.

Greenhouse Gases: Atmospheric gases such as carbon dioxide, methane, chlorofluorocarbons, nitrous oxide, ozone, and water vapor that slow the passage of re-radiated heat through the Earth’s atmosphere.

Gypsum: Gypsum is one of the most widely used minerals in the world. Most gypsum in the United States is used to make wallboard for homes, offices, and commercial buildings; a typical new American home contains more than seven metric tons of gypsum alone. Moreover, gypsum is used worldwide in concrete for highways, bridges, buildings, and many other structures that are part of our everyday life. Gypsum also is used extensively as a soil conditioner on large tracts of land in suburban areas, as well as in agricultural regions.

Hazardous Air Pollutant (HAP): An air pollutant listed under section 112 (b) of the federal Clean Air Act as particularly hazardous to health. Emission sources of hazardous air pollutants are identified by U.S. EPA, and emission standards are set accordingly.

Haze (Hazy): A phenomenon that results in reduced visibility due to the scattering of light caused by aerosols. Haze is caused in large part by man-made air pollutants.

Health-Based Standard (Primary Standard): A dosage of air pollution scientifically determined to protect against human health effects such as asthma, emphysema, and cancer.

Heat Recovery Steam Generator (HRSG): Recovers waste heat exhaust from a combustion turbine and generates steam

"Hot Spot": (See toxic hot spot.)

Hydrated Lime Injection: Calcium hydroxide, also known as slaked lime, is a chemical compound with the chemical formula Ca(OH)2. It is a colorless crystal or white powder, and is obtained when calcium oxide (called lime or quicklime) is slaked with water. It can also be precipitated by mixing an aqueous solution of calcium chloride and an aqueous solution of sodium hydroxide. A traditional name for calcium hydroxide is slaked lime, or hydrated lime.
Hydrated lime may be injected into the upper regions of a furnace where high temperatures are conducive to driving the reaction between the calcium and SO2 to achieve up to 70% SO2 removal.

Hydrocarbons: Compounds containing various combinations of hydrogen and carbon atoms. They may be emitted into the air by natural sources (e.g., trees) and as a result of fossil and vegetative fuel combustion, fuel volatilization, and solvent use. Hydrocarbons are a major contributor to smog.

Hydrogen Sulfide (H_2S): A colorless, flammable, poisonous compound having a characteristic rotten-egg odor. It is used in industrial processes and may be emitted into the air.

Incentives: Subsidies and other Government actions where the Governments's financial assistance is indirect.

Incineration: The act of burning a material to ashes.

Indirect emissions: *See* Indirect Source.

Indirect Source: Any facility, building, structure, or installation, or combination thereof, which generates or attracts mobile source activity that results in emissions of any pollutant (or precursor) for which there is a state ambient air quality standard. Examples of indirect sources include employment sites, shopping centers, sports facilities, housing developments, airports, commercial and industrial development, and parking lots and garages.

Industrial Source: Any of a large number of sources -- such as manufacturing operations, oil and gas refineries, food processing plants, and energy generating facilities -- that emit substances into the atmosphere.

Inert Gas: A gas that does not react with the substances coming in contact with it.

Inert gas blanket: “Blanket” of inert (chemically non-reactive) gas that fills the space above the condensate/crude oil to minimize volatilization and vapor loss.

Injection wells: Well in which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure. Two common types of injection gas and water. Separated gas from production wells or possibly imported gas may be reinjected into the upper gas section of the reservoir to maintain pressure.

Inspection and Maintenance (I&M) Program: A motor vehicle inspection program. The purpose of the I&M is to reduce emissions by assuring that cars are running properly. It is designed to identify vehicles in need of maintenance and to assure the effectiveness of their emission control systems on a biennial basis.

Integrated Sampling Device: An air sampling device that allows estimation of air quality components over a period of time through laboratory analysis of the sampler's medium.

Internal Combustion Engine: An engine in which both the heat energy and the ensuing mechanical energy are produced inside the engine. Includes gas turbines, spark ignition gas, and compression ignition diesel engines.

Inversion: A layer of warm air in the atmosphere that prevents the rise of cooling air and traps pollutants beneath it.

Kilowatt (kW): One thousand watts of electricity (See Watt).

Kilowatthour (kWh): One thousand watthours.

Kimray pump: Brand name of automated glycol pump used to circulate glycol in dehydrators.

Laser ignition: Ignition sequence replacing the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion.

Lead: A gray-white metal that is soft, malleable, ductile, and resistant to corrosion. Sources of lead resulting in concentrations in the air include industrial sources and crustal weathering of soils followed by fugitive dust emissions. Health effects from exposure to lead include brain and kidney damage and learning disabilities. Lead is the only substance which is currently listed as both a criteria air pollutant and a toxic air contaminant.

Leadership in Energy Efficiency and Design certification (LEED): The Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

Leak Detection and Repair (LDAR): Leak detection protocol, using either Photo-ionization detectors or infrared cameras promises to prevent volatile organic compound and hazardous air pollutant emissions from leaking equipment.

Lean Burn Engine: An engine that employs a fuel mixture with a higher air content than fuel as regulated by the AFRC with a normal exhaust oxygen concentration of 2% by volume, or greater.

Liquid Natural Gas (LNG): Natural gas that has been processed to remove either valuable components (e.g. helium) or those impurities that could cause difficulty downstream (e.g. water and heavy hydrocarbons) and then condensed into a liquid.

Lowest Achievable Emission Rate (LAER): Under the Clean Air Act, the rate of emissions that reflects (1) the most stringent emission limitation in the State Implementation Plan of any state for a given source unless the owner or operator demonstrates such limitations are not achievable; or (2) the most stringent emissions limitation achieved in practice, whichever is more stringent.

Low NOx Burners: One of several combustion technologies used to reduce emissions of nitrogen oxides.

Major Source: A stationary facility that emits a regulated pollutant in an amount exceeding the threshold level depending on the location of the facility and attainment with regard to air quality status. (See Source.)

Mass Spectrometry: Analytical technique used to measure the mass-to-charge ratio of ions.

Maximum Achievable Control Technology (MACT): Federal emissions limitations based on the best demonstrated control technology or practices in similar sources to be applied to major sources emitting one or more federal hazardous air pollutants.

Mean: Average.

Median: The middle value in a population distribution, above and below which lie an equal number of individual values; midpoint.

Megawatt (MW): One million watts of electricity (See Watt).

Melting Point: The temperature at which a solid becomes a liquid. At this temperature, the solid and the liquid have the same vapor pressure.

Mercury: A chemical element in the periodic table that has the symbol Hg. A heavy, silvery transition metal, mercury is one of five elements that are liquid at or near room temperature and pressure.

Mercury Deposition Network (MDN): The objective of the MDN is to develop a national database of weekly concentrations of total mercury in precipitation and the seasonal and annual flux of total mercury in wet deposition. The data will be used to develop information on spatial and seasonal trends in mercury deposited to surface waters, forested watersheds, and other sensitive receptors. See http://nadp.sws.uiuc.edu/mdn/

Mercury (Hg) Speciation: Mercury can assume many forms and, through interactions with the environment, can be transformed into a variety of structures. The most commonly known forms of mercury include: Elemental Mercury, divalent mercury (mercuric chloride) and methyl mercury.
The behavior of mercury in the atmosphere depends upon its form, or specie. Elemental mercury (Hgo) is typically not very reactive with global lifetime of a few months to a year and is thought to be transported significantly in the troposphere. Reactive gaseous mercury (RGM) species, are not well characterized chemically but are thought to be gaseous Hg(II)-bearing molecules such as HgCl2(g). RGM species are notable for being quickly deposited from the atmosphere to the surface and are thought to be readily available for conversion to methylmercury, a highly toxic form of mercury. Particulate mercury (Hg-P) is also quickly deposited and is often found in high concentrations near combustion sources. Although much lower in proportion than Hgo, the greater reactivity and deposition rates of RGM and Hg-P make them a larger environment concern. Chemical reactions that occur in the atmosphere can transform mercury between these various species.

Mesosphere: The layer of the Earth's atmosphere above the stratosphere and below the thermosphere. It is between 35 and 60 miles from the Earth.

Methane: A chemical compound with the molecular formula CH_4. It is the simplest alkane, and the principal component of natural gas. Burning one molecule of methane in the presence of oxygen releases one molecule of CO_2 (carbon dioxide) and two molecules of H_2O. It is also an important source of hydrogen in various industrial processes. Methane is a greenhouse gas.

Methyl Mercury: Mercury in the air eventually settles into water or onto land where it can be washed into water. Once deposited, certain microorganisms can change it into methylmercury, a highly toxic form that builds up in fish, shellfish and animals that eat fish. Fish and shellfish are the main sources of methylmercury exposure to humans. Methylmercury builds up more in some types of fish and shellfish than others. The levels of methylmercury in fish and shellfish depend on what they eat, how long they live and how high they are in the food chain. Mercury exposure at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages. Research shows that most people's fish consumption does not cause a health concern. However, it has been demonstrated that high levels of methylmercury in the bloodstream of unborn babies and young children may harm the developing nervous system, making the child less able to think and learn.

Minor Source: Any stationary source that does not qualify as a major source and directly emits, or has the potential to emit, less than one hundred tons per year or more of any air pollutant.

Mobile Sources: Sources of air pollution such as automobiles, motorcycles, trucks, off-road vehicles, boats, and airplanes. (See also stationary sources).

Monitoring: The periodic or continuous sampling and analysis of air pollutants in ambient air or from individual pollution sources.

National Ambient Air Quality Standards (NAAQS): Standards established by the United States EPA that apply for outdoor air throughout the country. There are two types of NAAQS. Primary standards set limits to protect public health and secondary standards set limits to protect public welfare.

National Emission Standards for Hazardous Air Pollutants (NESHAPS): Emissions standards set by the U.S. EPA for a hazardous air pollutant, such as benzene, which may cause an increase in deaths or in serious, irreversible, or incapacitating illness.

Natural Sources: Non-manmade emission sources, including biological and geological sources, wildfires, and windblown dust.

Net Metering: Arrangement that permits a facility (using a meter that reads inflows and outflows of electricity) to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption.

Neurotoxin: A toxin that acts specifically on nerve cells.

New Mexico Public Regulation Commission: The New Mexico Public Regulation Commission (PRC) regulates the utilities, telecommunications, motor carriers and insurance industries to ensure fair and reasonable rates, and to assure reasonable and adequate services to the public as provided by law.

New Source Performance Standards (NSPS): Uniform national EPA air emission standards that limit the amount of pollution allowed from new sources or from modified existing sources.

New Source Review (NSR): A Clean Air Act requirement that State Implementation Plans must include a permit review, which applies to the construction and operation of new and modified stationary sources in nonattainment areas, to ensure attainment of national ambient air quality standards. The two major requirements of NSR are Best Available Control Technology and Emission Offsets.

Nitrate (NO_3): A salt of nitric acid with an ion composed of one nitrogen and three oxygen atoms.

Nitric Oxide (NO): Precursor of ozone, NO_2, and nitrate; nitric oxide is usually emitted from combustion processes. Nitric oxide is converted to nitrogen dioxide (NO_2) in the atmosphere, and then becomes involved in the photochemical processes and / or particulate formation. (See Nitrogen Oxides.)

Nitrogen: Chemical element, which has the symbol N, and atomic number 7. Elemental nitrogen is a colorless, odorless, tasteless and mostly inert diatomic gas at standard conditions, constituting 78.1% by volume of Earth's atmosphere.

Nitrogen Enrichment Mode: NOx decreases while particulate emissions increase.

Nitrogen Oxides (Oxides of Nitrogen, NOx): A general term pertaining to compounds of nitric oxide (NO), nitrogen dioxide (NO_2) and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes, and are major contributors to smog formation and acid deposition. NO_2 is a criteria air pollutant, and may result in numerous adverse health effects.

Nonattainment Area: A geographic area identified by the U.S. EPA as not meeting the NAAQS for a given pollutant.

Noncarcinogenic Effects: Non-cancer health effects which may include birth defects, organ damage, morbidity, and death.

Non-Industrial Source: Any of a large number of sources -- such as mobile, area-wide, indirect, and natural sources -- which emit substances into the atmosphere.

Non-Methane Hydrocarbon (NMHC): The sum of all hydrocarbon air pollutants except methane. NMHCs are significant precursors to ozone formation.

Non-Methane Organic Gas (NMOG): The sum of non-methane hydrocarbons and other organic gases such as aldehydes, ketones and ethers.

Non-Point Sources: Diffuse pollution sources that are not recognized to have a single point of origin.

Non-Road Emissions: Pollutants emitted by a variety of non-road sources such as farm and construction equipment, gasoline-powered lawn and garden equipment, and power boats and outboard motors.

NOx Traps: Operate in a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water.

O_2 enrichment mode: Produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions.

Opacity: The amount of light obscured by particle pollution in the atmosphere. Opacity is used as an indicator of changes in performance of particulate control systems.

Organic Compounds: A large group of chemical compounds containing mainly carbon, hydrogen, nitrogen, and oxygen. All living organisms are made up of organic compounds.

Oxidant: A substance that brings about oxidation in other substances. Oxidizing agents (oxidants) contain atoms that have suffered electron loss. In oxidizing other substances, these atoms gain electrons. Ozone, which is a primary component of smog, is an example of an oxidant.

Oxidation: The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Oxidation catalysts: Element using a catalytic conversion for control of hydrocarbon and CO emissions.

Oxygenate: An organic molecule that contains oxygen. Oxygenates are typically ethers and alcohols.

Ozone (O_3): A strong smelling, pale blue, reactive toxic chemical gas consisting of three oxygen atoms. It is a product of the photochemical process involving the sun's energy and ozone precursors, such as hydrocarbons and oxides of nitrogen. Ozone exists in the upper atmosphere ozone layer (stratospheric ozone) as well as at the Earth's surface in the troposphere (ozone). Ozone in the troposphere causes numerous adverse health effects and is a criteria air pollutant. It is a major component of smog.

Ozone Depletion: The reduction in the stratospheric ozone layer. Stratospheric ozone shields the Earth from ultraviolet radiation. The breakdown of certain chlorine and / or bromine-containing compounds that catalytically destroy ozone molecules in the stratosphere can cause a reduction in the ozone layer.

Ozone-Forming Potential: (See Reactivity.)

Ozone Layer: A layer of ozone in the lower portion of the stratosphere -- 12 to 15 miles above the Earth's surface -- which helps to filter out harmful ultraviolet rays from the sun. It may be contrasted with the ozone component of photochemical smog near the Earth's surface which is harmful.

Ozone Precursors: Chemicals such as volatile organic compounds and oxides of nitrogen, occurring either naturally or as a result of human activities, which contribute to the formation of ozone, a major component of smog.

Particulate Matter (PM): Any material, except pure water, that exists in the solid or liquid state in the atmosphere. The size of particulate matter can vary from coarse, wind-blown dust particles to fine particle combustion products.

Passive Solar: A system in which solar energy alone is used for the transfer of thermal energy. Pumps, blowers, or other heat transfer devices that use energy other than solar are not used.

Permit: Written authorization from a government agency that allows for the construction and / or operation of an emissions generating facility or its equipment within certain specified limits.

Persistence: Refers to the length of time a compound stays in the atmosphere, once introduced. A compound may persist for less than a second or indefinitely.

Photovoltaic (PV) Module: An integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environment degradation, and suited for incorporation in photovoltaic power systems.

Pilot scale: Size of a system between the small laboratory scale (bench-scale) and full-size system.

Plant Pathology: The scientific study of plant diseases caused by pathogens (infectious diseases) and environmental conditons (physiological factors).

Plume: A visible or measurable discharge of a contaminant from a given point of origin that can be measured according to the Ringelmann scale. (See Ringelmann Chart.)

Plunger Lift System: Use gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

$PM_{2.5}$: Includes tiny particles with an aerodynamic diameter less than or equal to a nominal 2.5 microns. This fraction of particulate matter penetrates most deeply into the lungs.

PM_{10} (Particulate Matter): A criteria air pollutant consisting of small particles with an aerodynamic diameter less than or equal to a nominal 10 microns (about 1/7th the diameter of a single human hair). Their small size allows them to make their way to the air sacs deep within the lungs where they may be deposited and result in adverse health effects. PM_{10} also causes visibility reduction.

Pneumatic controls: Control systems using either compressed gas or air.

Point Sources: Specific points of origin where pollutants are emitted into the atmosphere such as factory smokestacks. (See also Area-Wide Sources and Fugitive Emissions.)

Polycyclic Aromatic Hydrocarbons (PAHs): Organic compounds which include only carbon and hydrogen with a fused ring structure containing at least two benzene (six-sided) rings. PAHs may also contain additional fused rings that are not six-sided. The combustion of organic substances is a common source of atmospheric PAHs.

Polymer: Natural or synthetic chemical compounds composed of up to millions of repeated linked units, each of a relatively light and simple molecule.

Pounds per million BTU (lb/mmBtu): A measure of the mass (of a pollutant) emitted for each million British thermal units (Btu) of energy fed to a combustion source. A BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Precipitator: Pollution control device that collects particles from an air stream. (See Electrostatic Precipitator.)

Prescribed Burning: The planned application of fire to vegetation to achieve any specific objective on lands selected in advance of that application.

Prevention of Significant Deterioration (PSD): A permitting program for new and modified stationary sources of air pollution located in an area that attains or is unclassified for national ambient air quality standards (NAAQS). The PSD program is designed to ensure that air quality does not degrade beyond those air quality standards or beyond specified incremental amounts. The PSD permitting process requires new and modified facilities above a specified size threshold to be carefully reviewed prior to construction for air quality impacts. PSD also requires those facilities to apply BACT to minimize emissions of air pollutants. A public notification process is conducted prior to issuance of final PSD permits.

Primary Particles: Particles that are directly emitted from combustion and fugitive dust sources. (Compare with Secondary Particle.)

Produced water: Water extracted from the subsurface with oil and gas. It may include water from the reservoir, water that has been injected into the formation, and any chemicals added during the production/treatment process.

Production Tax Credit (PTC): an inflation - adjusted 1.5 cents per kilowatthour payment for electricity produced using qualifying renewable energy sources.

Programmic logic controller (PLC): Control software for engine mapping / reactant injection requirements used to control the SCR system.

Public Utility Regulatory Policies Act of 1978 (PURPA): One part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. Principal among these were suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources.

Pulverized coal: is a coal that has been crushed to a fine dust in a grinding mill. It is blown into the combustion zone of a furnace and burns very rapidly.

Radionuclides: Atoms with an unstable nucleus, characterized by excess energy which is available to be imparted either to a newly-created radiation particle within the nucleus, or else to an atomic electron.

Reactive Organic Gas (ROG): A photochemically reactive chemical gas, composed of non-methane hydrocarbons, that may contribute to the formation of smog. Also sometimes referred to as Non-Methane Organic Gases (NMOGs). (See also Volatile Organic Compounds and Hydrocarbons.)

Reactivity (or Hydrocarbon Photochemical Reactivity): A term used in the context of air quality management to describe a hydrocarbon's ability to react (participate in photochemical reactions) to form ozone in the atmosphere. Different hydrocarbons react at different rates. The more reactive a hydrocarbon, the greater potential it has to form ozone.

Reasonably Available Control Measures (RACM): A broadly defined term referring to technologies and other measures that can be used to control pollution. They include Reasonably Available Control Technology and other measures. In the case of PM_{10}, RACM refers to approaches for controlling small or dispersed source categories such as road dust, woodstoves, and open burning.

Reasonably Available Control Technology (RACT): Control techniques defined in U.S. EPA guidelines for limiting emissions from existing sources in nonattainment areas. RACTs are adopted and implemented by states.

Reciprocating Internal Combustion Engine (RICE): An engine in which air and fuel are introduced into cylinders, compressed by pistons and ignited by a spark plug or by compression. Combustion in the cylinders pushes the pistons sequentially, transferring energy to the crankshaft, causing it to rotate.

Refraction: The change in direction of a light wave due to a change in its speed when it passes from one medium to another.

Regional Haze: The haze produced by a multitude of sources and activities which emit fine particles and their precursors across a broad geographic area. National regulations require states to develop plans to reduce the regional haze that impairs visibility in national parks and wilderness areas.

Regional Haze Rule: The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah.
The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. The first State plans for regional haze are due in the 2003-2008 timeframe. Five multi-state regional planning organizations are working together now to develop the technical basis for these plans.

Regulatory Impact Analysis (RIA): A tool used to assess the likely effects of a proposed new regulation or regulatory change.

Reid Vapor Pressure: Refers to the vapor pressure of the fuel expressed in the nearest hundredth of a pound per square inch (psi) with a higher number reflecting more gasoline evaporation.

Renewable Energy: Renewable Energy is energy derived from resources that are regenerative or, for all practical purposes, cannot be depleted.

Renewable Energy Resources: Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

Renewable Portfolio Standard (RPS): a mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.

Retrofit or retrofitting: The addition of new technology or features to older systems.

Rich Burn Engine: Any four-stroke spark ignited engine with a manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NOx (such as pre-combustion chambers) will be considered lean burn engines. Existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Ringelmann Chart: A series of charts, numbered 0 to 5, that simulate various smoke densities by presenting different percentages of black. A Ringelmann No. 1 is equivalent to 20 percent black; a Ringelmann No. 5 is 100 percent black. They are used for measuring the opacity or equivalent obscuration of smoke arising from stacks and other sources by matching the actual effluent with the various numbers, or densities, indicated by the charts.

Risk Assessment: An evaluation of risk which estimates the relationship between exposure to a harmful substance and the likelihood that harm will result from that exposure.

Risk Management: An evaluation of the need for and feasibility of reducing risk. It includes consideration of magnitude of risk, available control technologies, and economic feasibility.

Risk Management Plan (RMP): A document prepared by a project manager to foresee risks, estimate effectiveness, and to create response plans to mitigate them.

Sanctions: Actions taken against a state or local government by the federal government for failure to plan or to implement a State Implementation Plan (SIP). Examples include withholding of highway funds and a ban on construction of new sources of potential pollution.

Scrubber: An air pollution control device that uses a high energy liquid spray to remove aerosol and gaseous pollutants from an air stream. The gases are removed either by absorption or chemical reaction.

Secondary Particle: Particles that are formed in the atmosphere. Secondary particles are products of the chemical reactions between gases, such as nitrates, sulfur oxides, ammonia, and organic products.

Selective Catalytic Reduction (SCR) or selective non-catalytic reduction (SNCR): Selective catalytic reduction means a noncombustion control technology that destroys NOx by injecting a reducing agent (e.g., ammonia) into the flue gas that, in the presence of a catalyst (e.g., vanadium, titanium, or zeolite), converts NOx into molecular nitrogen and water.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2.

Sensitive Groups: Identifiable subsets of the general population that are at greater risk than the general population to the toxic effects of a specific air pollutant (e.g., infants, asthmatics, elderly).

Sequestration: Capture and long term storage of carbon. See also Carbon Capture and Storage

Smog: A combination of smoke and other particulates, ozone, hydrocarbons, nitrogen oxides, and other chemically reactive compounds which, under certain conditions of weather and sunlight, may result in a murky brown haze that causes adverse health effects.

Smoke: A form of air pollution consisting primarily of particulate matter (i.e., particles released by combustion). Other components of smoke include gaseous air pollutants such as hydrocarbons, oxides of nitrogen, and carbon monoxide. Sources of smoke may include fossil fuel combustion, prescribed and agricultural burning, and other combustion processes.

Solar Energy: The radiant energy of the sun, which can be converted into other forms of energy, such as heat or electricity.

Solar Thermal Collector: A device designed to receive solar radiation and convert it into thermal energy. Normally, a solar thermal collector includes a frame, glazing, and an absorber, together with the appropriate insulation. The heat collected by the solar thermal collector may be used immediately or stored for later use. Solar Thermal Collector, Special: An evacuated tube collector or a concentrating (focusing) collector. Special collectors operate in the temperature (low concentration for pool heating) to several hundred degrees Fahrenheit (high concentration for air conditioning and specialized industrial processes).

Soot: Very fine carbon particles that have a black appearance when emitted into the air.

Source: Any place or object from which air pollutants are released. Sources that are fixed in space are stationary sources and sources that move are mobile sources.

Spark ignition (SI): Ignition of combustion within an engine using spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI.

Stack Gas Bypass: The practice of routing some portion of exhaust gas, often from a large boiler, around the pollution control equipment, and into the exhaust stack. This is usually done to introduce hot, unscrubbed, gas into the stack to mix with and raise the temperature of the cool, scrubbed gas above its acid dew point and/or to increase plume buoyancy and dispersion. If the gas cools to its acid dew point, acid mists and droplets may fall out near the stack, or corrode unprotected stack linings.

State Implementation Plan (SIP): The group of plans and regulations submitted by a state to the U.S. EPA for implementation of the federal Clean Air Act.

Stationary Sources: Non-mobile sources such as power plants, refineries, and manufacturing facilities which emit air pollutants. (See also mobile sources).

Still vent column: Emission point for regeneration of glycol streams, resulting in vapors of water, VOC and HAPs.

Stoichiometric engine: An engine with the chemically correct proportion of fuel to air in the combustion chamber during combustion.

Storage Tank: Any stationary container, reservoir, or tank, used for storage of liquids.

Stratosphere: The layer of the Earth's atmosphere above the troposphere and below the mesosphere. It extends between 10 and 30 miles above the Earth's surface and contains the ozone layer in its lower portion. The stratospheric layer mixes relatively slowly; pollutants that enter it may remain for long periods of time.

Subsidy: Financial assistance granted by the Government to firms and individuals.

Sulfur Dioxide (SO_2): A strong smelling, colorless gas that is formed by the combustion of fossil fuels. Power plants, which may use coal or oil high in sulfur content, can be major sources of SO_2. SO_2 and other sulfur oxides contribute to the problem of acid deposition. SO_2 is a criteria air pollutant.

Sulfur Oxides (SOx): Pungent, colorless gases (sulfates are solids) formed primarily by the combustion of sulfur-containing fossil fuels, especially coal and oil. Considered major air pollutants, sulfur oxides may impact human health and damage vegetation.

Syngas: Syngas is the gas product resulting from gasification processes and can be used as a fuel to drive power generation or a feedstock for chemical synthesis.

Tailpipe emissions: Products of burning fuel in the vehicle's engine emitted from the vehicle's exhaust system.

Thief hatch: Opening in the top of the stock tank that allows tank access to the interior of the tank for withdrawal or measurement of fluid.

Title V: A section of the 1990 amendments to the federal Clean Air Act that requires a federally enforceable operating permit for major sources of air pollution.

Topography: The configuration of a surface, especially the Earth's surface, including its relief and the position of its natural and man-made features.

Total dissolved solids (TDS): The combined content of all inorganic and organic substances contained in a liquid which are present in a molecular, ionized or micro-granular (colloidal sol) suspended form.

Total Suspended Particulate (TSP): Particles of solid or liquid matter -- such as soot, dust, aerosols, fumes, and mist -- up to approximately 30 microns in size.

Toxic Hot Spot: A location where emissions from specific sources may expose individuals and population groups to elevated risks of adverse health effects -- including but not limited to cancer -- and contribute to the cumulative health risks of emissions from other sources in the area.

Trading Credits: The basic concept of a cap and trade system is that the government turns a certain quantity of emissions into a marketable commodity, called a credit, which is then allowed to be bought and sold freely on the market. See http://www.epa.gov/airmarkets/trading/basics.html

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Triethylene glycol (TEG) dehydrator: Any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

Troposphere: The layer of the Earth's atmosphere nearest to the surface of the Earth. The troposphere extends outward about five miles at the poles and about 10 miles at the equator.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Underground Storage Tank (UST): Refers to tanks used to store gasoline underground.

United States Environmental Protection Agency (U.S. EPA): The federal agency charged with setting policy and guidelines, and carrying out legal mandates for the protection of national interests in environmental resources.

Urea: An organic compound of carbon, nitrogen, oxygen and hydrogen, with the formula CON_2H_4 or $(NH_2)\ CO_2$ or CN_2H_4O. Used as a catalyst for SCR applications.

Vanadium: A chemical element in the periodic table that has the symbol V and atomic number 23. A rare, soft and ductile element, vanadium is found combined in certain minerals and is used mainly to produce certain alloys.

Vapor recovery unit (VRU): A system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors formed inside completely sealed crude oil or condensate tanks.

Vehicle Miles Traveled (VMT): The miles traveled by motor vehicles over a specified length of time (e.g., daily, monthly or yearly) or over a specified road or transportation corridor.

Visibility: A measurement of the ability to see and identify objects at different distances. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter.

Visibility Reducing Particles (VRP): Any particles in the atmosphere that obstruct the range of visibility.

Volatile: Any substance that evaporates readily.

Volatile Organic Compounds (VOCs): Carbon-containing compounds that evaporate into the air (with a few exceptions). VOCs contribute to the formation of smog and / or may themselves be toxic. VOCs often have an odor, and some examples include gasoline, alcohol, and the solvents used in paints.

Watt (Electric): The electrical unit of power. The rate of energy transfer equivalent to 1 ampere of electric current flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Weight of Evidence: The extent to which the available information supports the hypothesis that a substance causes an effect in humans. For example, factors which determine the weight-of-evidence that a chemical poses a hazard to humans include the number of tissue sites affected by the agent; the number of animal species, strains, sexes, relationship, statistical significance in the occurrence of the adverse effect in treated subjects compared to untreated controls; and the timing of the occurrence of adverse effect.

Welfare-Based Standard (Secondary Standard): An air quality standard that prevents, reduces, or minimizes injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation.

Wet Flue Gas Desulfurization (FGD): In wet scrubbers, the flue gas enters a large vessel (spray tower or absorber), where it is sprayed with water slurry (approximately ten percent lime or limestone). The calcium in the slurry reacts with the SO2 to form calcium sulfite or calcium sulfate. A portion of the slurry from the reaction tank is pumped into the thickener, where the solids settle before going to a filter for final dewatering to about 50 percent solids. The calcium sulfite waste product is usually mixed with fly ash (approximately 1:1) and fixative lime (approximately five percent) and disposed of in landfills. Alternatively, gypsum can be produced from FGD waste, which is a useful by-product.

Wind Energy: Energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators. Wind pushes against sails, vanes, or blades radiating from a central rotating shaft.

Woodburning Pollution: Air pollution caused by woodburning stoves and fireplaces that emit particulate matter, carbon monoxide and odorous and toxic substances.

Zeolite: Minerals that have a micro-porous structure.

Zero Emissions Dehydrator: A Zero Emissions Dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler instead of venting to the atmosphere.

Table of Mitigation Options Not Written with Rationale

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SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Stationary RICE (Small and large engines)	Emission limit on existing engines (1g/hp hr and 2g/hp hr)	Will incorporate this into the NSPS mitigation option and note that it will apply to existing engines.
	Replacing ignition systems to decrease false starts	This option is generally covered in the Operation and Maintenance mitigation option
	Replace piston rod packing (pumps)	This will be added to the Operation and Maintenance mitigation option.
	Minimize (control?) engine blow downs	This is already a common industry practice and has been deleted as an option
	Utilize exhaust gas analyzers to adjust AFR	This was included in the Oxidation Catalysts and AFRC on Lean Burn Engines option.
	Smart AFRC (air-fuel-ratio-controller)	Included in the other AFRC options
	Replace gas engine starters with electric air compressors	Negligible emissions reductions for applying this option.
	Provide training for field personnel on engine maintenance with regard to AQ considerations	Incorporated into Option titled "Adherence to Manufacturers' Operation and Maintenance Requirements"
Oil and Gas: Mobile and Non-Road		
Oil and Gas: Rig Engines	Analysis of all drill rigs – replace the dirtiest 20%	Will reference in Tier 2-4 Mitigation Option Development, but also move to overarching discussion to determine the priority on rig engine reductions
	Electric Powered Drill Rig	Not selected due to low feasibility around availability of electricity
Oil and Gas: Turbines		
Oil and Gas: Exploration & Production (Tanks)	Mufflers	Does not apply to Air Quality.
	Centralized Collection for Existing Sources	This option is not feasible for retrofit application in the San Juan Basin

SECTION	**MITIGATION OPTION TITLE**	**RATIONALE FOR NOT WRITING**
Oil and Gas: Exploration & Production (Dehydrators/Separators/ Heaters)	Centralized Dehydrators	Already or will be incorporated in other papers on centralization
	Optimization and automation	Incorporated into the Option under Stationary RICE subsection.
	Low/Ultra low NOx burners	Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area smaller than the technology is capable of providing emission reduction.
	Install VRU	Principle of the option as applied is explained in the Option titled "Install VRU" under subsection for E&P Tanks.
	Centralized Dehydrators	Principle of the option is incorporated into the Option under Stationary RICE. Additionally, the San Juan Basin does not have a high need for wellhead dehydration.
Oil and Gas: E&P Pneumatics/ Controllers/ Fugitives	Directed inspection and maintenance program	Addressed by Option title "Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance" in Midstream section.
Oil and Gas: Midstream Operations	Install Flares	Never submitted.
Oil and Gas: Overarching Issues		
Power Plants: Future	Integrated Gasification Combined Cycle (IGCC) Political Aspects and Incentives	Combined with Integrated Gasification Combined Cycle (IGCC) Technical Aspects and listed as mitigation option "Integrated Gasification Combined Cycle (IGCC)"
Power Plants: Overarching	Four Corners Area Mercury Studies	Combined with Participate and Support Mercury Deposition Studies
Other Sources:	Apply Uniform Regulations Between Jurisdictions for Dust Control	Never submitted.
	Fugitive Dust Road Mitigation Plan	See option papers on oil & gas road dust mitigation.
	Include Multi-Modal Transportation Options in 2035 Transportation Plan	Scope of this option is very large. A proposal was submitted to DOE.
	Pursue Clean Cities Designation for Western Slope	This was not awarded by DOE. Not clear just who would house and how funding could be sustainable.
	Auto Licensing or Registration Additional Tax	Group determined this was unlikely to be economically feasible at this time.
	Oil and Gas Fleet Retrofit / Replacement	Numerous options were written as part of the oil & gas section dealing with vehicles.

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Other Sources:	Consider Ambient Air Quality Before Burning Prescribed Fire	Never submitted.
	Develop Controls on Agricultural Burning in Colorado	Never submitted.
Energy Efficiency, Renewable Energy, Conservation	Corporate Rebate/incentives for Energy Efficiency	Combined with Building Standards for Increased Commercial and Residential Energy Efficiency (EE)
	Pilot Neighborhood project to Change Behavior to Reduce Energy Use – Increase Efficiency	Combined with Audits of Low Income Areas to find Simple Solutions
	Solar/PV Applications	Never submitted.
	Optimization of Compression	Incorporated into the Option under Stationary RICE subsection titled “Optimization and automation and Centralized Collection for New Sources”
	Micro Turbines	Incorporated into Option titled “Cogeneration/Combined Heat and Power”
	Product Capture/Maximize Efficiency	Never submitted.
	Multi-Phase Pipeline	Never submitted.
	Comprehensive Impacts of efficiency	Never submitted.
	Efficiency/Conservation on individual level	Never submitted.
	Sustainable business practices	Never submitted.
	Zero Waste	Never submitted.

GENERAL: PUBLIC COMMENTS

General Public Comments

Comment
Air quality in the Four Corners Area has been studied and cussed and discussed for several decades while the pollution problems grow and grow. We sincerely hope that measurable benefits to our environment will be the product of this massive piece of work by the Four Corners Air Quality Task Force. Polluting industries and enforcement agencies cannot continue to "turn their backs" on what IS happening to the quality of our air. It is our right to breathe clean air. We all know that San Juan County has serious air quality issues. San Juan County is ranked in the top 10% of worst counties in the United States for toxic releases to the environment according to Scorecard, a pollution information web site. These toxic releases include volatile organic compound emissions from oil and gas facilities, and power plant emissions such as particulate matter (PM) and sulfur dioxide. Many other toxic emissions are listed. All of these pollutants are threats to human health, the land and water. Enough is Enough! Now is the time to take action to clean up our environment! Regulatory agencies need to begin much stronger enforcement of current regulations and work toward more stringent regulations. Further degradation of our environment is not acceptable. State cancer profiles show that this area has the highest rate of cancer in New Mexico. Respiratory disease is high in the Four Corners Area. A comprehensive health study for the entire Four Corners Area would most likely reveal even more alarming health problems among our population. Clean up of area coal fired power plants and mandatory emissions controls and clean up of oil and gas facilities are necessary for the health and well being of the people. Health is wealth.
I've not read all the details of the report but I think there seems to be something missing. I don't see any analysis of the future demand on this area in terms of energy. There is a fast growing school of thought that indicates coal can provide the energy bridge the United States needs to exit the Middle East. I think people need to understand that the coal resources here in the San Juan Basin could become a big part of a new energy strategy for transportation. Electric cars and electric high speed trains could be used to help replace the demand for middle east oil being used now for gasoline and jet fuel. If this happens and I think it is coming in the next 10 years, what will we see here? Is any planning being done for that? If you think there is a lot of CO2 from 3 power plants, what if there were 20? This may seem like bad news but it's not if we have a plan. For less than the cost of the Iraq war, we could install the infrastructure to convert the coal here into H2 and CO2. The H2 could be used in new power plants driving engines turning generators thereby reducing the requirement for steam from water and the CO2 could be captured and piped to Bakersfield to be injected into the heavy oils there in enhance oil recovery. The power grid will would require significant upgrades to accommodate the additional load in addition to providing ways for wind and solar power to come on the system. Instead of planning for war, let's plan for peace. This is a big effort. We need a leader with some vision at the Federal level. Is there someone who could have understood the impact of the internet and pushed to develop that infrastructure? Internet super highway -> I say Energy Super Highway!

Comment
The Southern Ute Indian Tribe Growth Fund (SUGF) appreciates the opportunity provided to the public to allow for review and comment on the Draft Four Corners Air Quality Task Force Report (Version 7); furthermore SUGF, is appreciative of the tremendous undertaking of the various resources that have come together to develop a range of possible air quality mitigation options that may remedy air quality issues in the Four Corners area. SUGF understands that this document is non-conclusive, and does not convey consensus of the various participating bodies regarding the mentioned mitigation options. It is further understood that these developed options may be considered by the various regulatory bodies to be implemented into air quality management strategies. At that time, it is recommended that public participation similar to this effort be duplicated. As you may be aware, production of natural gas is critical to the Southern Ute Indian Tribe's (Tribe) economic base and growth. The SUGF, a private investment entity of the Tribe supports development of its natural resources, yet remains cognizant of its responsibility to protect the environment. This is exemplified through Tribal processes such as conditional approval(s) of future oil and gas development that will require significant mitigation measures involving installation of control technologies on compression units. Another significant development occurring is the continual development of the Tribe's Air Quality Program, through the establishment of the Southern Ute Indian Tribe/State of Colorado Environmental Commission.
BP believes that the establishment of the Four Corners Task Force is a very useful venue for stakeholders and regulators to discuss air quality issues with the ultimate goal of managing air quality in the region. Developing strategies to measurably improve air quality requires extensive technical, engineering and policy analyses. In addition, such analyses require time and should not be influenced by arbitrary schedules. BP believes that solutions to the issues should be crafted on the basis of air quality improvement and economic efficiency. Control requirements based on a "one size solution" may not result in measurable air quality improvements nor be the most economic solution for improving air quality. BP also believes that it is important for the Task Force to focus on understanding source receptor relations in the region through modeling and analysis of existing air quality data as well as emission data.
I could not find the Federal Register notification for this superficial 'public comment' period. This process is fatally flawed as proper 'government to government meetings' have not been held. The formal notification has not been provided to all American Indian Nations and official respective American Indian Nation Tribal Council has not been officially made known. How will such federal mandates affect the sovereignty of American Indian Nations? This appears to violate basic principles of American Indian Nation Treaties as it does the Law of Nations. It appears, these federal agencies are recruiting non-profits to further international agendas for their federal acquisitions while attempting to impose hidden taxation. These federal regulatory actions certainly appear to emphasize regulation without representation as it promotes no accountability while encouraging implementation of un-ratified international conventions such as Kyoto. I attended the first meeting held in Farmington New Mexico for the Four Corners area regarding Air Quality on November 4, 2005. I spoke with a federal officer in her official capacity who acknowledged this process was indeed implementing the Kyoto Treaty that is un-ratified by U.S. Congress. She also acknowledged that the way the federal agencies were working around this un-ratified treaty was by entering into Memorandums of Understanding (MOU) between the respective State governments. These MOU's are signed by State governors as is the case with New Mexico State Governor Bill Richardson. New Mexico Governor Richardson proposed adoption of a regional climate change scheme to California Governor Arnold Schwarzenegger as stated in Executive order June 9, 2005. New Mexico Governor Richardson displays a definite conflict of interest as he continues to enjoy the pleasure of the United Nations while acting as United Nations Ambassador and more of an International Citizen, during his term as New Mexico Governor. A man cannot serve two masters anymore than he can be a citizen of two countries.

Comment

I received an email from a member of Montezuma Vision Project May 2, 2007 who wrote in reference to membership; "Most of the people are progressives who are interested in promoting planning for good quality of life."

The main intent behind those who claim to be Progressives is to reduce "right" to privilege and "liberty" to servitude. Progressives enjoy collectivism implemented upon the masses while they enjoy their appointed and self anointed aristocracy oligarchy. The first U.S. Progressive Party formed in 1912 and has found its niche in liberalism and the environmental movement. There are Progressives connected to Democratic Socialist parties. Progressives believe and implement the old Roman Prodigal estate schemes promoted by IUCN (International Union for Conservation of Nature) which in reality is promoting Sustainable Development as specified in Agenda 21- 1992 Rio Summit Declaration.

The Kyoto Protocol was created by an Intergovernmental Panel on Climate Change established in 1988 jointly by World Meteorological Organization and the United Nations Environment Programme. The Convention (Kyoto Protocol To The United Nations Framework Convention On Climate Change) was adopted by the Conference of the Parties meaning Parties to the Convention, May 1992, while in New York. The Montreal Protocol on Substances that Deplete the Ozone Layer was adopted by the Conference of the Parties September 1987.

The federal officer while I was at November 4, 2005 meeting, acknowledged this entire process was truly implemented the Untied Nations, World Bank, IMF, Federal Reserve, and agenda for Sustainable Development which is also known as Agenda 21. The federal officer told me that there is a system in place for schemes that allow for a 'pay to pollute' program. She provided the example of power plants on the East Coast that do not have state of the art environmental equipment and cannot be fitted or converted with such state of the art environmental equipment. Certificates from power plants in Western U.S. who are newer and have up dated equipment as well as cleaner coal, would sell certificates to the Eastern U.S power plants as a means of offsetting Eastern power plant pollution. In reality, this is a pay to pollute scheme that mirrors the new-politically correct scheme of paying to have a ‘Carbon Imprint or Footprint’. Example: a representative from Nature Conservancy conducts a Carbon Imprint intake of your life. The calculations are conducted on life style such as how often a person drives a car, fly’s an airplanes, rides a bicycle, uses a microwave oven and so forth. Once the representative determines the Carbon Imprint number, the person is expected to pay an outrageous sum of money (Federal Reserve Notes) to an environmental non profit of his or her choice to off set the Carbon Imprint. In reality, this is extortion at its best while providing a steady source of income to environmental non profits who may not otherwise obtain such vast forms of income. It certainly appears this entire scheme is just another form of taxation forced upon the public.

While I was in attendance at November 4, 2005 meeting I listened to the key-note speaker talk of new EPA standards that must be implemented. In reality, he was telling the public this unfunded and unjustified federal mandate ‘must’ be complied to. Meanwhile, he mentioned the Four Corners area has dust & silt particles blown in from other larger cities as far away as Phoenix and Tucson Arizona and beyond.

There were a lot of charts on the walls and the mercury issue in the Four Corners was displayed as being mainly caused from the power plants that exist in the area. First of all, there is a natural occurrence of mercury in the San Juan Mountains. Second, plants are known to absorb mercury from the ground. If the plants and trees absorb this mercury from the ground and a wildfire of significant proportions occurs what is going to happen? The mercury will be released by residual ash and debris back into the ground and even into the water supply. This cycle was not demonstrated at this meeting nor is it ever discussed. This monitoring process and so called evidence collecting done in this entire process is fatally flawed while it certainly indicates fatal deficiencies in the precision in monitoring as it suggests other uncertainties.

Comment

The picture displayed upon the website depicting this proposed Four Corners Air Quality catastrophe is fatally flawed. Photographs can be easily manipulated to reflect whatever the crisis especially with today's technology. The pictures did not show what type of a day it was such as was it a cold day or a hot day? Sometimes in this area of the Four Corners depending upon what time of the morning and what moisture is in the air, visibility can be poor from the natural moisture in the air as well as wind passing through can cause dust from the ground to be in the air. The EPA expecting to regulate such natural processes in nature is absurd. The natural occurrences were not discussed at this meeting anymore than it was reflected in any of the charts or photographs.

I see this entire process as in terminal as it is fatally in error. Most of all, I see federal agencies and cohorts attempting to play God while trying to control nature. This is preposterous to claim the environment that includes animals, plants and all of nature is above humans. This is perversions of natural law at its best especially when EPA claims it can control wind, dust and weather while expecting an area such as the Four Corners to keep that dust from blowing in from other areas. It is just as absurd to create this hyped up crisis just to sell certificates to pollute and extort money from the public. Cease and desist all these actions of implementing un-ratified illegal international treaties through abusing MOU's and other such agreements. Stop trying to play God while creating a crisis just to extort money from the public and expand progressivism.

The Association between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County

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Abstract

The New Mexico Department of Health (NMDOH) Environmental Health Tracking Project has been compiling and analyzing data on air quality and respiratory health of New Mexicans. While other studies in the United States have shown an association between the frequency of asthma attacks and ground level ozone in large urban areas, few researchers have focused on largely rural communities in the desert southwest. To perform the analysis, the daily number of asthma-related emergency room visits to emergency departments for 2000 to 2003 were matched to daily ozone levels during April – September. The ozone concentration data were obtained from nationwide datasets compiled by the Environmental Protection Agency, but were collected by the NM Environment Department Air Quality Bureau. The study focused on ground level ozone during April to September because ground level ozone accumulates when warmer and longer days cause nitrogen oxides and volatile organic compounds in the air to react and generate ozone. These reactions can cause ozone concentrations to increase by more than 20 parts per billion (ppb) from one day to the next.

The analysis used a statistical model to predict the effect that these changes in ozone concentrations have on the number of asthma-related emergency room visits. Two health outcomes were considered: daily presence or absence of an asthma-related medical visit and the number of visits. Ozone was associated with asthma-related medical visits. The distribution of ozone concentrations was similar to that observed in many large cities. Increased ozone (lagged two days) was associated with increased odds of at least one asthma-related medical visit by 42 %. The study found that when ozone increased by 20 ppb the number of emergency room visits increased by about 34%. While this is a small increase in the number of visits, sensitive persons may want to monitor air quality index forecasts to help limit their exposure to ozone. Ozone concentrations typically are highest in the early afternoon, so sensitive individuals should try to reduce their outdoor activities during this part of the day.

Background

Exposure to air pollutants, such as ozone, nitrogen dioxide, sulfur dioxide and particulates, have repeatedly been shown to be associated with negative health outcomes, including mortality, reduced lung function growth and asthma (Dominici et al. 2003, Gauderman et al. 2000, Tolbert et al. 2000). However, most of these studies have been conducted in large urban areas, with many of these in the eastern United States or the western coast. The distribution of these air pollutants and the sources of these pollutants may differ considerably from rural areas or areas in the high desert Southwest.

In an Environmental Protection Agency (EPA) study of air quality in New Mexico, Sather showed that the ozone concentrations in San Juan County were increasing and were among the highest in EPA sites in the Southwest (Sather 2004). He further concluded that the levels were similar throughout most of the county and that NOx and alkanes were the main volatile organic compounds in the ozone development.

Health outcomes associated with air quality have not been studied in a rural, southwestern high desert environment. Thus, we conducted a study of asthma-related medical visits in San Juan County and present an alternative statistical approach that deals with some of the limitations of data obtained in a rural area.

Study Area

San Juan County, New Mexico is a rural county in the high desert of northwest New Mexico, with an elevation of 5145 feet and an average rainfall of 9.3 inches. The county covers over 5000 square miles, but had a population of 114,000 in 2000, resulting in a low density of 21 people per square mile. The main city is Farmington, with a population of 38,000. All other towns have a population under 10,000, with most being considerably smaller. Although the area is rural, the county residents are concerned about air pollution and the potential health risks, especially with respect to asthma. Major industries center on coal, oil and natural gas production. Air pollution sources include coal-based power plants and production of gas and oil. Two more large coal-fired power plants may be built within the county. With the increased number of forest fires in the West and the hundreds of miles that the smoke from these fires has traveled, forest fires also have had a considerable impact on the air quality.

Asthma Surveillance

Through a CDC cooperative agreement starting in 2000, the NMDOH developed a statewide asthma surveillance system. With renewed funding NMDOH has continued surveillance and has expanded its role to education, improving access to care and reducing the effects of environmental factors associated with asthma. In 2003, NMDOH received funding through the CDC Environmental Public Health Tracking Program to link environmental exposure data with health outcome data. As part of this program, NMDOH, in collaboration with the UNM, linked data on air quality and asthma in San Juan County. Both hospitalization discharge and urgent care visit information were obtained through the statewide asthma surveillance system for January 1, 2000 through December 31, 2003. Age, sex and zip code of residence were obtained for each visit.

Air Quality Data

New Mexico Environment Department (NMED) collected air quality data from three monitors within the county. The Bloomfield and San Juan Substation monitors ran continuously and collected hourly data on air quality and weather conditions. While both monitors were operating as of January 1, 2000, ozone was not collected at the Bloomfield station until June 7, 2000. The Bloomfield monitor is approximately 15 miles east of Farmington in the town of Bloomfield. The Substation is located at the Shiprock Electrical Substation, approximately 15 miles west of Farmington, near the Public Service Company of New Mexico San Juan Generating Station, and a few miles north of the Arizona Public Services Four Corners Power Generating Station.

Methods

Statistical Methods

Two health outcomes were considered: the number of asthma-related medical visits per day and a binary indicator as to whether or not any medical visits during a day were asthma-related. Since we were primarily interested in the association of ozone levels with asthma-related medical visits, we restricted the yearly study period to May 1 through September 15, when over 90% of the eight hour average ozone concentrations were above 50 ppb. Variables for which data were collected hourly were summarized as both the daily maximum hourly value and the maximum eight hour average value. While the maximum eight hour value for ozone is used in regulatory standards, we also wanted to consider if shorter term peaks, such as those indicated by high daily maximum hourly values, may be important to health outcomes. For measurements taken at two stations, the association between the two daily ozone values was assessed and the maximum of the two values was used.

Modeling

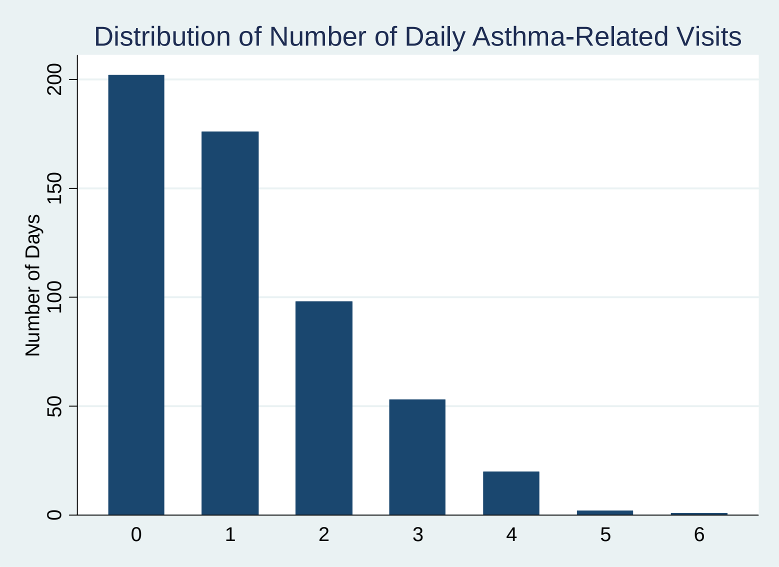
The daily number of asthma-related medical visits was modeled using Poisson regression. Primary exposure variables were the maximum daily values for the eight-hour average hourly ozone concentrations. Lags of zero to five days from exposure to visit day were examined to determine the amount of time between exposure and effect. Covariates were included to adjust for seasonal components, year, week day, holidays (lagged zero to two days) and school year. Variables were included only if the significance level was less than 0.10. Single pollutant models were obtained by adding an exposure variable to this best covariate model. Only the variables significant at $p<0.10$ in the single pollutant models were examined in the overall model, but these variables were retained only if the significance level was less than 0.05. Since the number of daily visits generally was small, logistic regression was used to model whether or not any asthma-related medical visit was observed on a day. The same procedure, including the same predictor variables and covariates, that was used in the Poisson regression modeling was used in the logistic regression modeling.

Since the number of daily asthma-related medical visits was small and the number of days with zero counts was larger than expected under the Poisson model, the Zero-Inflated Poisson (ZIP) model also was used (Dobbie and Welsch 2001; Hall and Zhang 2004). This model contains two components: the first predicts the probability of observing at least one asthma-related visit in a day (binary component) and the second estimates the number of visits (count component). The coefficients in the two components are estimated simultaneously. Only variables significant at < 0.10 at entry were retained. All statistical modeling was done in R.

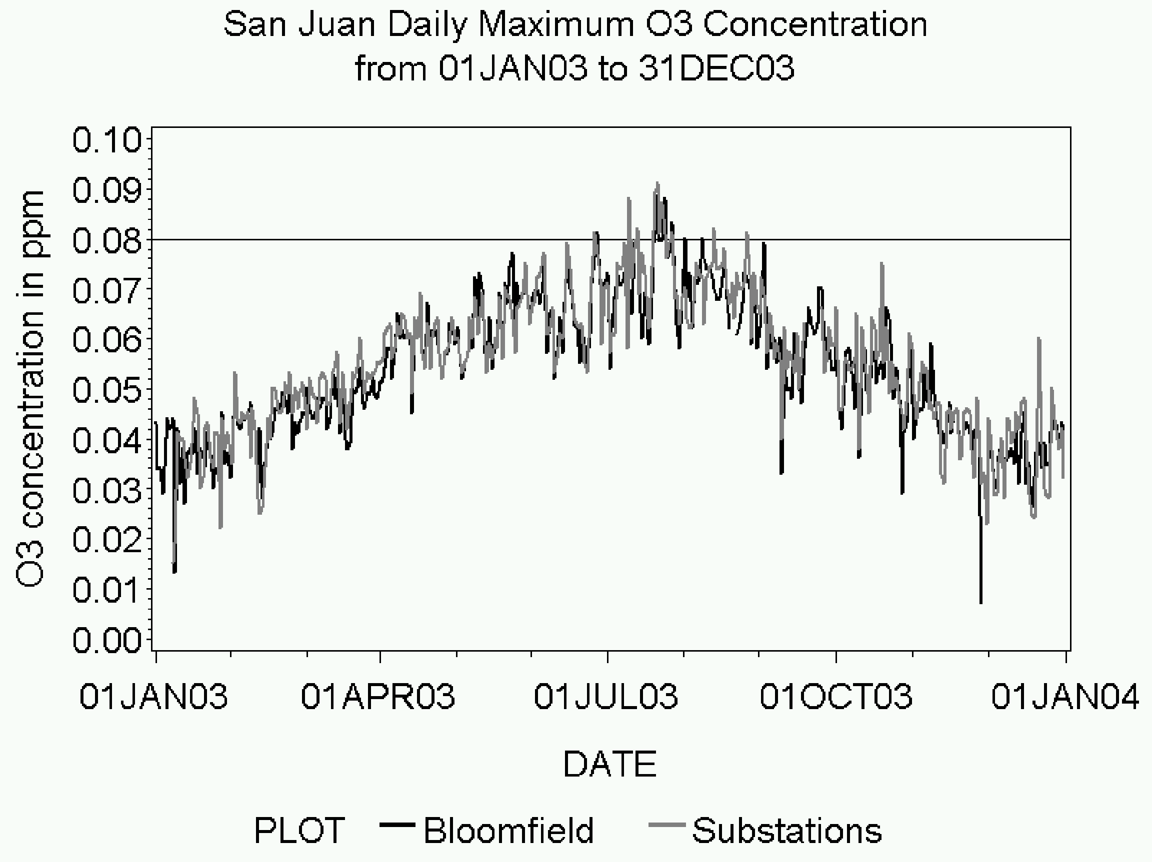
Results

Health Outcomes

During the summer months (May 1 through September 15) of 2000 through 2003, 627 asthma-related medical visits were reported in San Juan County. Asthma-related visits ranged from 0 to 6 per day, with a median of 1 and mode of 0 (Figure 2). At least one patient made an asthma-related visit on 350 (63.4%) of the 552 study days. Although age, gender and zip code information were available, the number of visits or proportion of days with an asthma-related visit were too low for successful modeling, so no assessment by these variables are included.



Air Quality: Ozone peaks during the summer months. Analyses were restricted to the summer months, from May 1 through September 15. Ozone concentrations at the two monitors were very similar. For air quality parameters that were measured at two monitors, the maximum value was used. The median daily eight hour maximum ozone level was 63 ppb during the summer months, with a maximum value of 85. All air quality variables exhibited distributions skewed to high values, but ozone was the least skewed. The maximum value for ozone was only 35% of the median.



Regression Models: To model the odds of at least one asthma-related medical visit, logistic regression models with adjustment for the seasonal components, weekday, holiday and spring school time were developed. The best lags were two days for ozone. Ozone was associated with increased odds of at least one asthma-related medical visit (OR=1.42; 95% CI: 1.09, 1.95; p < 0.01). To model the count of the number of asthma-related medical visits, Poisson regression models were also used with adjustment for the seasonal components, weekday, holiday and year. Ozone was associated with an increased count of visits, with a relative risk of 1.11 per 10 ppb ozone (95% CI: 0.98, 1.24). Zip models were used to simultaneously model the probability of any asthma-related medical visits and the number of visits per day. Adjustment factors were determined for the separate binary and count components, with no adjustment in the binary component and adjustment for the seasonal components, weekday, holiday and year in the count component. While ozone was significant in the binary component (p<0.05), the overall association was not significant (p=0.09).

Discussion

We have shown that ambient ozone concentrations are associated with asthma-related medical visits in a rural area of the high desert in San Juan County, New Mexico. While there is an indication that the number of visits rise along with increases in ozone, the most important result is that the odds of asthma-related visits increase with increasing ozone (1.42; 95% CI: 1.09, 1.85).

The basic association of increased asthma consequences with increased ozone has been shown in many urban areas. The distribution of ozone values in San Juan County is similar to those observed in other studies, but the extreme values are not necessarily as high in San Juan County. For example, while the highest single hour and eight-hour averages were 96 ppb and 83 ppb in San Juan County, respectively, studies in Atlanta had maximum one hour concentrations of 132 ppb, (Stieb et al. 1996; Tolbert et al. 2000). However, studies in Seattle (8-hour maximum=83.1 ppb) and Santa Clara County, CA (1-hour maximum=70 ppb) had similar, but slightly lower maximum concentrations (Lipsett et al. 1997; Norris et al. 1999).

The high values in San Juan County are of concern. The federal regulatory standard is 84 ppb for the three-year average of the annual fourth highest eight hour average. During the study period, the county reached a three-year average of 78 ppb. Furthermore, in an EPA study of air quality in New Mexico, Sather concluded that the ozone concentrations in San Juan County during 2000-2003 were higher than the previous three years and were among the highest among EPA regional sites in the Southwest including Arizona, Utah, Colorado, New Mexico and Texas (Sather 2004). Sather also showed that ozone was high in many parts of the county, including the middle of the county near the population center and the sparsely populated western and northeastern parts of the county. The largest hourly change in ozone concentrations was only 18 ppb, indicating that nitrogen oxides and alkanes were the main compounds in the ozone development. Similar to studies of urban areas, the most effective lag is two days between the occurrence of the ozone concentration and the asthma-related visits (Hwang et al. 2004; Stieb et al. 1996).

Studies to address health issues in rural areas are more often hampered by small counts than similar studies in urban areas. Use of standard methods such as Poisson regression may not be appropriate, and the modification of the data to look at binary outcomes may lose vital information. Thus, a model such as the ZIP model may be appropriate in many rural health studies, as in other studies with small counts.

This study includes several limitations. As discussed above, studies in rural areas are often limited by small sample sizes. However, our modeling approach effectively dealt with small, including zero, counts. While the county covers a large area, there were only two monitors for each air quality parameter. Furthermore, address information was limited to zip code, so there was no effective method to obtain better exposure information than that obtained from one monitor or the average of two monitors. However, we did limit the study sample to people residing in the county. Prior studies of the spatial trends in ozone indicated some but not significant differences in ozone across the county.

Conclusions

Although a rural area, San Juan County, New Mexico experiences high ozone concentrations, as high as some urban areas and high for the Southwest. The analysis used a statistical model to predict the effect that these changes in ozone concentrations have on the number of asthma-related emergency room visits. Two health outcomes were considered: daily presence or absence of an asthma-related medical visit and the number of visits. Ozone was associated with asthma-related medical visits. The distribution of ozone concentrations was similar to that observed in many large cities. Increased ozone (lagged two days) was associated with increased odds of at least one asthma-related medical visit by 42 %. The study found that when ozone increased by 20 ppb the number of emergency room visits increased by about 34%. While this is a small increase in the number of visits, sensitive persons may want to monitor air quality index forecasts to help limit their exposure to ozone. Ozone concentrations typically are highest in the early afternoon, so sensitive individuals should try to reduce their outdoor activities during this part of the day.

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Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States

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ABSTRACT

The Intermountain West is currently experiencing increased growth in oil and gas production, which has the potential to affect the visibility and air quality of various Class I areas in the region. The following work presents an analysis of these impacts using the Comprehensive Air Quality Model with extensions (CAMx). CAMx is a state-of-the-science, "one-atmosphere" Eulerian photochemical dispersion model that has been widely used in the assessment of gaseous and particulate air pollution (ozone, fine [$PM_{2.5}$], and coarse [PM_{10}] particulate matter). Meteorology and emissions inventories developed by the Western Regional Air Partnership Regional Modeling Center for regional haze analysis and planning are used to establish an ozone baseline simulation for the year 2002. The predicted range of values for ozone in the national parks and other Class I areas in the western United States is then evaluated with available observations from the Clean Air Status and Trends Network (CASTNET). This evaluation demonstrates the model's suitability for subsequent planning, sensitivity, and emissions control strategy modeling. Once the ozone baseline simulation has been established, an analysis of the model results is performed to investigate the regional impacts of oil and gas development on the ozone concentrations that affect the air quality of Class I areas. Results indicate that the maximum 8-hr ozone enhancement from oil and gas (9.6 parts per billion [ppb]) could affect southwestern Colorado and northwestern New Mexico. Class I areas in this region that are likely to be impacted by increased ozone include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.

IMPLICATIONS

Population growth in the western United States is driving a rapid increase in the generation of electricity and fossil fuel production, leading to higher NO_x emissions and the potential to affect the visibility and air quality of Class I areas in the region. Although total emissions from oil and gas development are small compared with other categories such as coal-fired power plants and automobiles, they occur in remote locations and can have a disproportionate effect on the air quality of national parks and wilderness areas. The following work provides an analysis of these impacts on ozone concentrations using a state-of-the-science photochemical dispersion model.

INTRODUCTION

High ozone (O_3) levels at the Earth's surface, such as the photochemical smog that frequently envelopes Los Angeles in the summer, have typically been regarded as an urban air quality problem. However, a disturbing trend in recent years has been the rise of tropospheric O_3 in remote regions of the western United States,[1] many of which are Class I areas (international parks, national wilderness areas that exceed 5000 acres in size, national memorial parks that exceed 5000 acres in size, and national parks that exceed 6000 acres in size) as designated by the Clean Air Act. Possible explanations for this trend include increasing background concentrations, largely due to emissions from Asia[2–4] or changes in the magnitude or distribution of regional emissions.[1]

O_3 is a strong oxidant that can reduce lung function and damage plant tissue at relatively low concentrations. In March 2008, the U.S. Environmental Protection Agency (EPA) tightened existing National Ambient Air Quality Standards (NAAQS) for O_3 to 75 parts per billion (ppb; assessed as the fourth highest monitored O_3 concentration value over a running average 8-hr period, averaged over 3 continuous years) from the previous 80 ppb, effectively reducing the compliance level of the O_3 NAAQS by 9 ppb. In April 2008, the EPA Clean Air Science Advisory Committee clarified earlier recommendations to the EPA administrator that a primary O_3 standard between 60 and 70 ppb is necessary to protect human health.[5]

O_3 is formed through a complex series of chemical reactions involving nitrogen oxides (NO_x) and volatile organic compounds (VOCs) in the presence of sunlight. To combat rising O_3 levels, these precursors must be reduced. However, as oil and gas development in the western United States continues to accelerate, there is significant potential that emissions from these sources will exacerbate the existing O_3 problem. Although emissions from oil and gas development may appear small as compared with other emission categories such as coal-fired power plants and automobiles, they typically occur in remote regions of the country, far removed from urban areas, and can have a disproportionate effect on the air quality of Class I areas. For example, NO_x emissions from an internal combustion engine at a gas well may react with terpenes (a reactive VOC) emitted from pine forests and form O_3 in an area where the right mix of precursors was previously not available for this reaction to take place. This is especially worrisome because recent observations indicate that many remote wilderness areas and national parks, such as Mesa Verde National Park in southwestern Colorado, are confronted with O_3 concentrations that are trending toward the EPA's acceptable limits. Very near Mesa Verde National Park are rapidly growing oil and gas extraction operations in northwestern New Mexico. As this type of development continues throughout the west, it is essential to understand its potential negative impact on air quality in some of our nation's most cherished protected areas. It is important to notice that wintertime O_3 concentrations exceeding 140 ppb were recently observed near the Jonah-Pinedale Anticline natural gas field in Wyoming's Upper Green River Basin.[6]

This study uses sophisticated meteorological and air pollution models to simulate air quality in the western United States, with a particular focus on O_3 concentrations in our national parks and wilderness areas. The Western Regional Air Partnership (WRAP) provided the necessary inputs to the model for meteorology, emissions, and boundary concentrations, originally developed for regional haze analysis and planning. The modeling system used in this work is similar to other systems used in demonstrating compliance with current NAAQS.[7,8]

Understanding the impacts of emissions from particular source categories such as oil and gas development is crucial to develop effective strategies that help reduce regional air pollution. Although this article focuses on the impact of O_3 pollution, the concept of "one-atmosphere" computer modeling is identified in the WRAP 2008-12 Strategic Plan for future regional air quality analyses.[9] This approach is used to investigate several issues related to regional formation and transport of air pollutants such as the primary and secondary NAAQS for O_3 and particulate matter, visibility protection, and mitigating health and ecosystem effects due to excessive nitrogen deposition and toxic air pollutants such as mercury.

APPROACH

The modeling system comprises three major components: the Penn State University/National Center for Atmospheric Research Mesoscale Model (known as MM5[10]), a regional weather model; CAMx (Comprehensive Air Quality Model with Extensions[11]), a chemistry transport model; and SMOKE (Sparse Matrix Operator Kernel Emissions[12]), an emissions processing system that chemically, spatially, and temporally allocates the raw emissions data. CAMx simulates the emissions, dispersion, chemical reactions, and removal of pollutants in the troposphere by solving the pollutant continuity equation for each chemical species on a three-dimensional grid. Although computationally expensive, this type of simulation accounts for the complex physical and chemical processes that govern the fate of pollutants. The 36-km coarse-grid horizontal domain used for the air quality modeling consists of the contiguous 48 U.S. states, contiguous lands and waters of southern Canada and northern Mexico, portions of the Pacific and Atlantic oceans, most of the Gulf of Mexico, all of the Gulf of California, and the southern Hudson Bay region. The CAMx 36-km grid includes 148 cells in the east-west dimension and 112 cells in the north-south dimension. The vertical grid used in the MM5 modeling defines the CAMx vertical structure. The MM5 simulations used a terrain-following coordinate system defined by pressure using 34 layers that extend from the surface to the model top at 100 mbar. To reduce computational costs, a layer-averaging scheme was adopted, reducing the original 34 layers to 19 vertical layers. Figure 1 presents a map of the computational modeling domain; it also shows the states that form the western region of the United States, the area of interest for this analysis. MM5 provides the wind fields that CAMx needs to determine the transport of chemical species, as well as other meteorological variables such as temperature and pressure. A detailed emission inventory specifies the hourly flux of emissions from numerous area and point pollutant sources. The emission inventory focuses on pollutants that are important for regional haze and visibility in the selected model domain, which includes the contiguous United States, southern Canada, and northern Mexico. The inventory consists of 22 emission categories (e.g., automobiles, power plants, forest fires, and oil and gas development) and was originally developed in support of WRAP's regional haze simulations.[13] Figure 2 shows the annual NO_x emissions associated with oil and gas development in the western United States. Note that significant emissions occur throughout the Intermountain West, particularly in the Four Corners region of northwestern New Mexico.

The oil and gas emission inventory used here was initially compiled for WRAP's regional modeling, with a focus on NO_x and oxidized sulfur (SO_x) emissions, which are precursors to fine particulate nitrate and sulfate, respectively. However, subsequent versions of this inventory have been developed and improved, and emissions of some species, such as VOCs, have been substantially revised. Although this study uses an earlier version of the WRAP oil and gas emission inventory, it is anticipated that the general trends presented provide a gross indication of the impact of this source category on regional O_3 formation.

In this study, a simulation for the year 2002 is performed with CAMx and corresponds to the "base modeling year" being investigated by WRAP and the latest year in which detailed emissions were readily available. The first step in this analysis is the comparison between predicted O_3 concentrations with available observations. Once the model performance of this base-case simulation is deemed adequate, a second CAMx simulation that includes all of the base-case emissions except those from oil

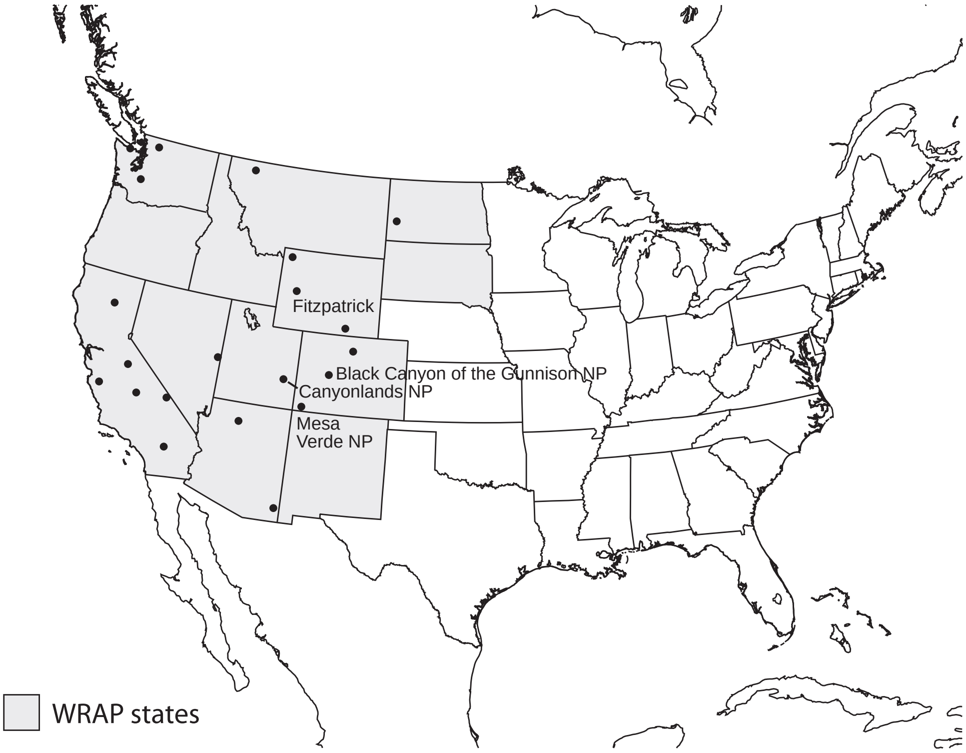

Figure 1. Map of the 36-km computational domain used in this study. The shaded area shows the analysis domain and corresponds to those states that are part of the contiguous WRAP region (Alaska and Hawaii are WRAP members, but are not in the modeling domain). The circles in the figure indicate the location of CASTNET sites used in this study for the model performance evaluation of O_3.

and gas is used to evaluate their air quality impacts in the western United States. The impacts are determined by looking at the difference between the base case and the "absent oil and gas emissions" simulations.

ANALYSIS

Model Performance Evaluation

O_3 concentrations predicted by the model are evaluated by comparing the surface layer values with available hourly measurements of ground-level O_3 at 22 sites from the Clean Air Status and Trends Network (CASTNET)[14] monitoring network. These sites fall within the western region of the United States and are indicated by circles in Figure 1. An evaluation of CAMx's skill in predicting O_3 is done in accordance with the EPA's suggested performance guidelines for O_3 modeling.[15,16] Observation/prediction pairs are excluded from the analysis when the observed concentration is below a certain cutoff level. The EPA has suggested a cutoff value of 60 ppb; however, most of the sites considered here are located in remote, pristine areas, and thus the cutoff value is set at 20 ppb because natural O_3 levels range typically between 10 and 25 ppb.[17] Table 1 shows the annual model performance statistics for 1-hr O_3 in the western region of the United States during 2002. In general, CAMx is able to consistently predict the general annual trends for O_3 concentrations, with a mean normalized bias of −1.6% and a mean absolute normalized error of 22.7%, falling well within the EPA's guidelines for acceptable model performance. Figure 3 shows estimated monthly normalized error and bias bar plots. Throughout the year, the model also performs within EPA goals; for instance, the largest errors are less than 25% during the summer (August). The model seems to show some seasonality in the errors and biases; its performance is better for the winter and fall and slightly worse for the spring and summer. The model has a tendency to underpredict O_3 concentrations during the summer and fall, with the largest biases in August (−15%), whereas it overpredicts O_3 during the winter and spring. Table 1 also shows the

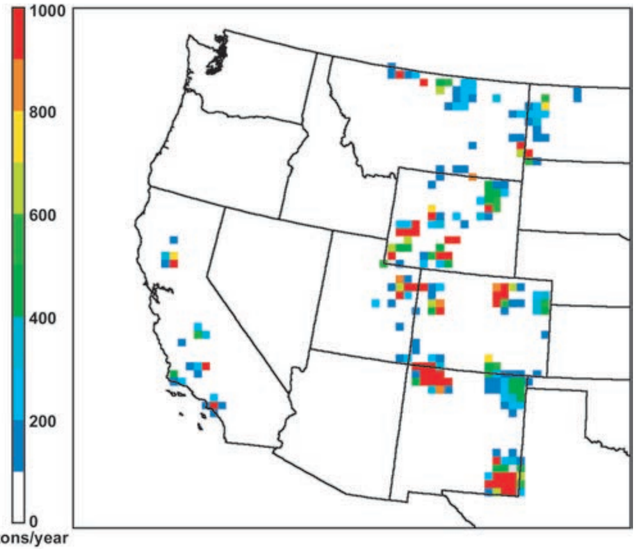

Figure 2. Annual 2002 WRAP NO_x emissions (t/yr) from oil and gas exploration and production activities in the western United States.

Table 1. Annual model performance statistics for 1-hr O_3 calculated with 22 CASTNET sites in the contiguous WRAP region of the western United States.

Statistic	EPA Goal	Mesa Verde National Park	Gunnison National Park	Canyonlands National Park	Fitzpatrick	CASTNET Sites (Western United States)
Mean observation		46	50	48	48	47
Mean estimation		46	52	43	46	44
Standard deviation observations		10	9	10	8	13
Standard deviation estimates		13	10	11	9	12
Mean bias error		−0.02	2.6	−5	−1.5	−3
Mean normalized bias error (%)	< ±15%	0.9	7.3	−8.4	−1.7	−1.6
Mean absolute gross error		8	7	9.6	7.2	10
Mean absolute normalized gross error (%)	<35%	16.9	15.7	19.8	14.9	22.7
Mean fractional error (%)		16.9	14.6	22	15.2	23
Mean fractional bias (%)		−1.4	5.3	−11.9	−3.5	−5.8

Notes: All values in ppb except where indicated.

annual performance statistics for sites located near places for which the impacts from oil and gas emissions will be discussed in the following sections. It is important to notice that for these specific sites the predicted hourly O_3 concentrations also fall within EPA guidelines for acceptable model performance. In general, the performance in most of these sites is better than in the western United States as a whole, with normalized errors ranging from 14.9% (Fitzgerald) to 19.8% (Canyonlands National Park). Many of these sites are located in very complex terrain, so given the coarse resolution of the model, its performance is reasonable and even comparable to that of other studies.[18–20] Figure 4 shows 8-hr moving averages of predictions and observations for the CASTNET sites presented in Table 1. The figure illustrates that the model does not seem to accurately capture the complex diurnal variations in the observations. However, it shows that throughout the year the model follows the general trends revealed by the observations, particularly on a monthly average basis. In the case of Canyonlands, the model variation is larger than the other sites and the model has a pronounced tendency to underpredict observations during the summer and fall.

Oil and Gas Impacts

As indicated above, this study relies on two separate CAMx simulations to estimate the potential impacts of oil and gas emissions in the western United States. A more regional perspective of O_3 formation is illustrated in Figure 5. Figure 5a shows the highest 8-hr O_3 concentration at each model grid cell that occurred during the 2002 base-case simulation. As expected, there are high concentrations (exceeding 110 ppb) downwind of major urban areas such as Los Angeles, San Francisco, Salt Lake City, and Denver. The figure also demonstrates that for a large region of the southwestern United States that includes remote regions of Nevada, Wyoming, Utah, Arizona, New Mexico, and Colorado, the new 8-hr primary NAAQS-related threshold for ground-level O_3 (75 ppb) is exceeded at least once during 2002 for many Class I areas. Generally, these maxima occur during hot, sunny days with light winds, when the meteorology is most favorable for O_3 production. These periods also typically correspond to peak VOC emissions from biogenic and anthropogenic sources. The impact of NO_x and VOC emissions from oil and gas development on O_3 in the western United States is shown in Figure 5b. Note that the values for each grid cell in Figure 5b correspond to the dates for which O_3

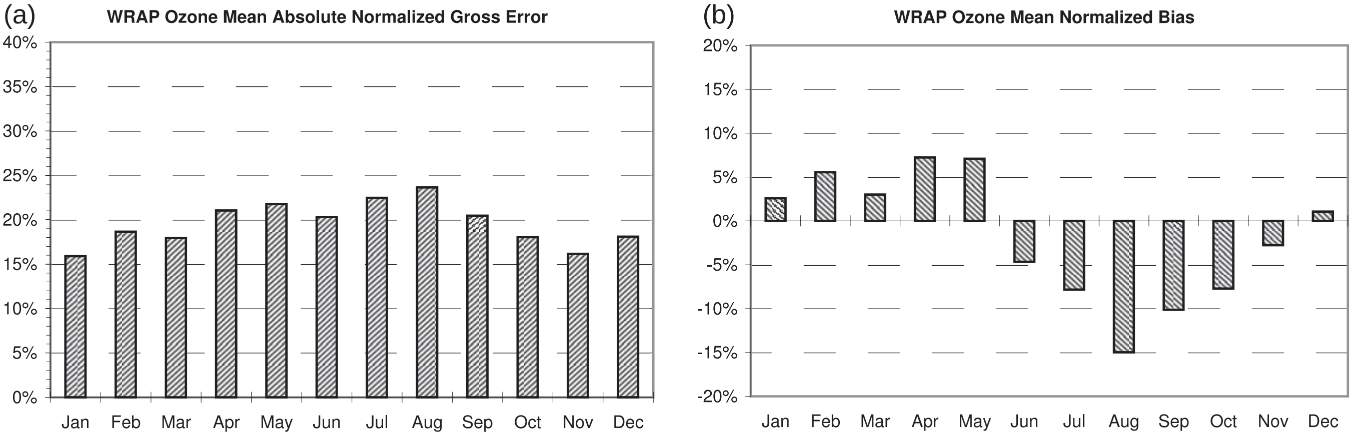

Figure 3. Monthly model performance (a) mean absolute normalized gross error and (b) mean normalized bias bar plots for 1-hr O_3 calculated with 22 CASTNET sites in the WRAP region.

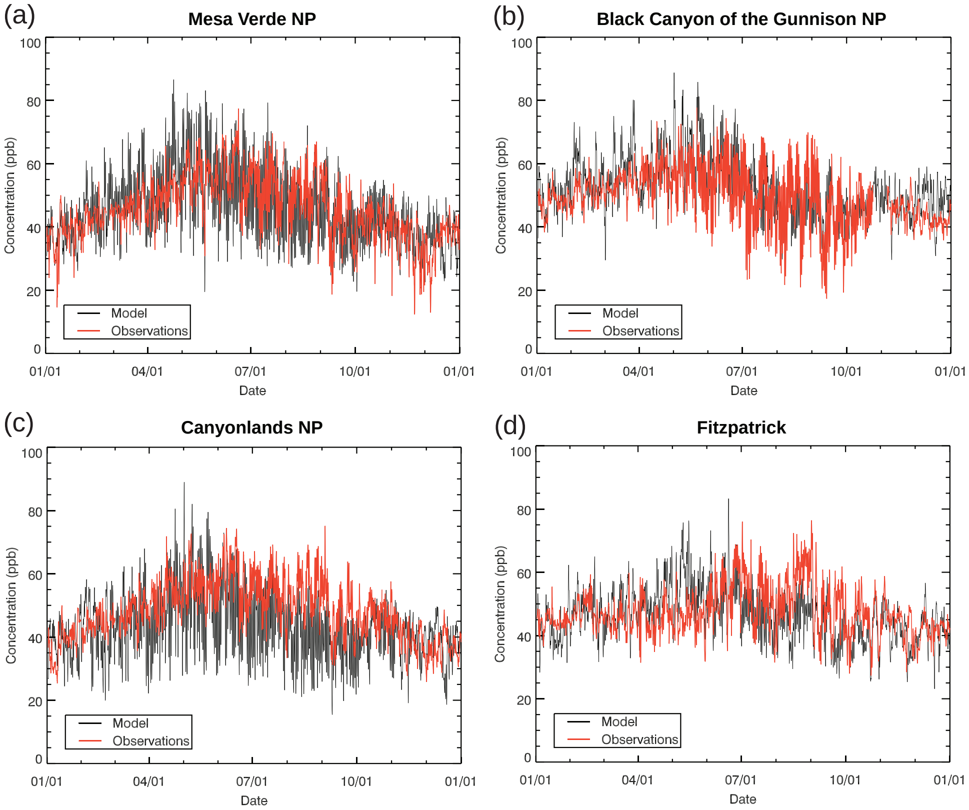

Figure 4. Time series comparison between model (black line) and observed (red line) 8-hr average O_3 (base case) for the CASTNET sites included in Table 1: (a) Mesa Verde National Park, (b) Black Canyon of the Gunnison National Park, (c) Canyonlands National Park, and (d) the Fitzpatrick Class I area included in Table 1.

maxima occur (Figure 5a), but in this case, the O_3 concentration is solely due to emissions from oil and gas development. Although the peak O_3 maxima throughout the west are typically quite small, there is a strong signature of 1–2 ppb of O_3 throughout New Mexico, Colorado, and Wyoming, with a pattern that approximates the

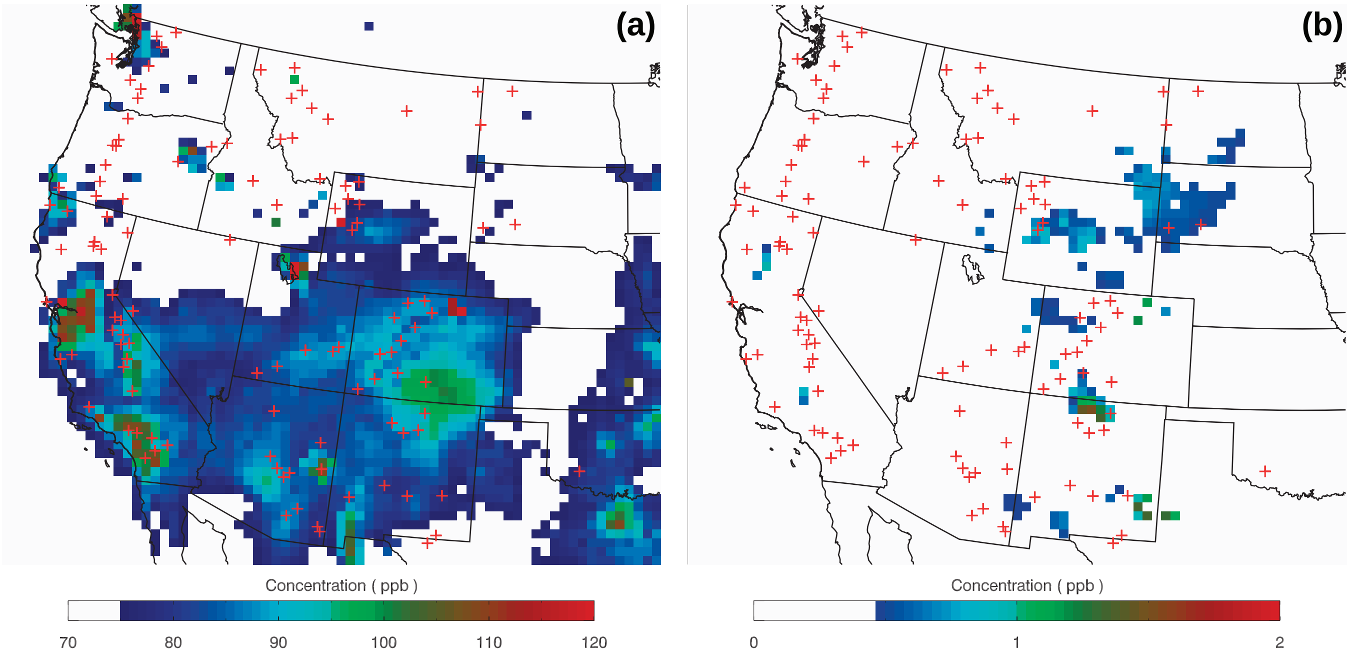

Figure 5. Peak predicted annual O_3 maxima (ppb, 8-hr average) in the western United States from (a) the 2002 base-case simulation and (b) the enhancement from VOC and NO_x emissions from oil and gas development that correspond to the dates and times of O_3 maxima. The locations of all Class I areas in the region are indicated with red crosses.

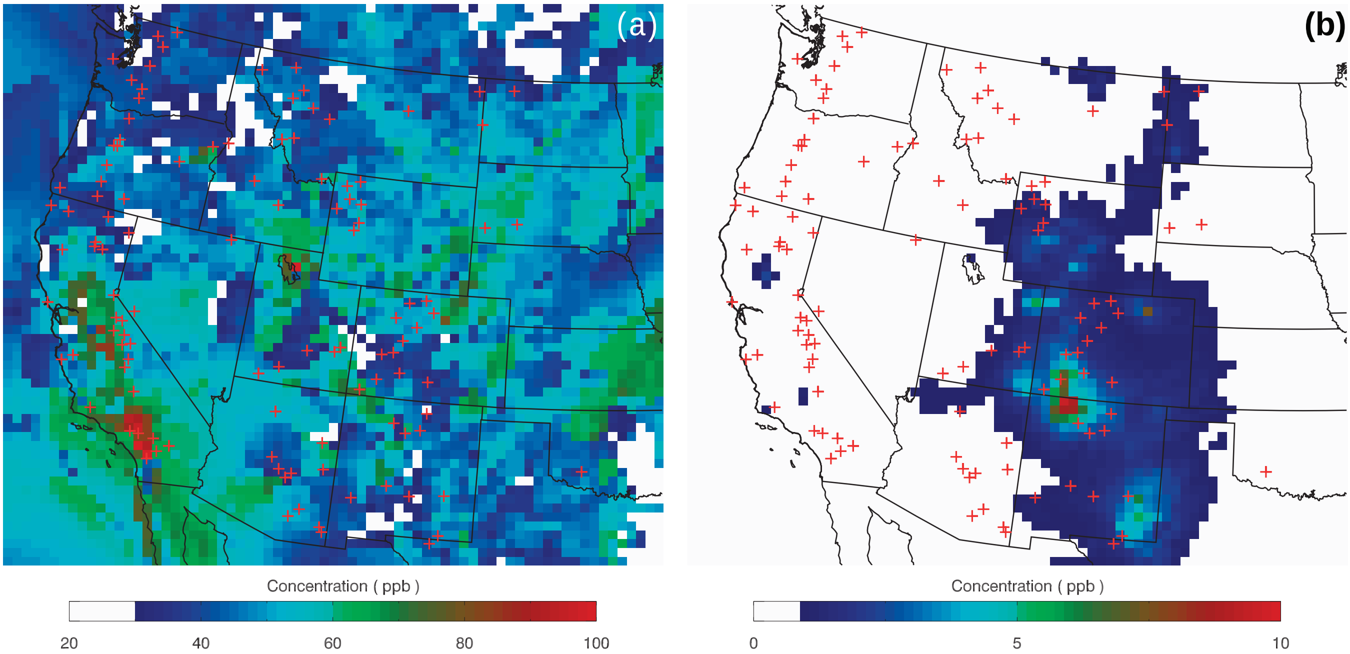

Figure 6. Peak predicted annual O_3 (ppb, 8-hr average) enhancement from VOC and NO_x emissions from (b) oil and gas development in the western United States and (a) corresponding O_3 concentrations from the 2002 base-case simulation. The locations of all Class I areas in the region are indicated with red crosses.

emissions shown in Figure 2. However, the maximum possible impacts of oil and gas emissions do not necessarily coincide in time with the maximum possible O_3 concentrations, as illustrated in Figure 6. The maxima 8-hr O_3 enhancement from oil and gas alone shown in Figure 6b demonstrates that significant O_3 concentrations (maximum of 9.6 ppb) could affect southwestern Colorado and northwestern New Mexico. Class I areas in this region that are likely to be impacted by increased O_3 include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico. O_3 concentrations for the base-case simulation during this period (Figure 6a) range from 40 to 70 ppb; thus in some places (e.g., Mesa Verde National Park and Weminuche) oil and gas have the potential to put these places out of compliance with the new EPA O_3 standard. Figure 6b shows that there are three regions where oil and gas have the potential for maximum impacts on Class I areas: southwestern Colorado and northern New Mexico, the southeast corner of New Mexico, and western Wyoming. Table 2 shows the date when the maximum impacts due to oil and gas emissions are achieved and their corresponding base-case concentrations for some of the Class I area sites. In general, these results show that most of the impacts occur during the summer and early fall. However, from this table alone it is not possible to know, for each site, the percentage of time when high impacts are observed in spring and early summer compared with summer and

Table 2. Maximum O_3 impacts due to oil and gas, date the maxima occur, and base-case concentration in some Class I area sites located in the western United States.

Class I Area	Latitude (°)	Longitude (°)	Base-Case Concentration (ppb)	Maximum Impact Oil and Gas (ppb)	Date Maximum Impact Occurs
Weminuche	37.65	−107.80	40	7	August 5
San Pedro Parks	36.11	−106.81	35	5	September 8
Carlsbad Caverns	32.14	−104.48	49	4	August 27
Wheeler Peak	36.57	−105.42	37	3	August 24
Pecos	35.93	−105.64	40	3	September 13
Bandelier	35.78	−106.26	61	3	June 30
Mesa Verde	37.20	−108.48	64	3	July 13
Saltcreek	33.61	−104.37	49	3	July 29
Great Sand Dunes	37.72	−105.51	33	2	September 8
La Garita	37.96	−106.81	38	2	August 6
Bridger	42.97	−109.75	52	2	April 4
Fitzpatrick	43.27	−109.57	52	2	April 4
Grand Teton	43.68	−110.73	50	1	April 24
Washakie	43.95	−109.59	44	1	September 10

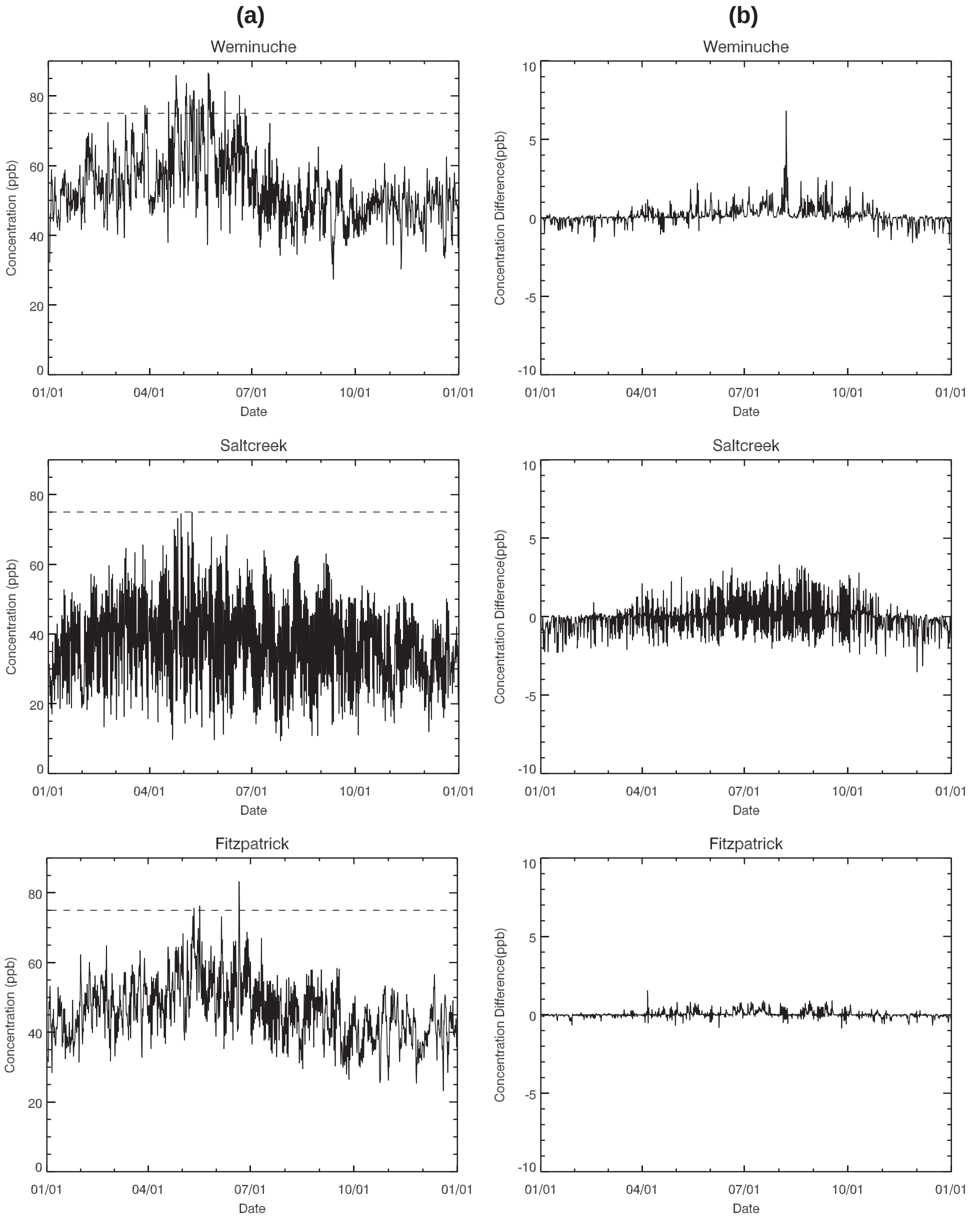

Figure 7. Time series of (a) simulated base-case O_3 (ppb, 8-hr average) for sites representative of one of the three main regions identified as having larger impacts from oil and gas emissions (Weminuche, Saltcreek, and Fitzpatrick Class I areas). (b) The change in O_3 concentration (ppb, 8-hr average) at each site solely due to VOC and NO_x emissions from oil and gas development.

early fall. Figure 7 is a much better indicator of this tendency. Figure 7 shows 8-hr moving average time series for the base case and the oil and gas impacts for a few selected sites from Table 2, including Weminuche, where the largest impacts are observed. The other sites represent one of the other two main regions identified as having larger impacts from oil and gas emissions. The general trend of modeled O_3 (Figure 7a) is low concentrations during the colder winter months, when limited photochemistry will occur, and higher concentrations during the warmer late spring and summer months, when meteorological conditions are more favorable to O_3 production. Additionally, enhanced biogenic VOC emissions that occur during the spring and summer will further influence O_3 formation in the region. The dashed lines in Figure 7a show the new EPA standards for O_3. It is evident from the figure that there are various instances in which O_3 concentrations are higher than the new NAAQS in many of these Class I areas, particularly during the late spring and early summer. Figure 7b shows the resulting changes in predicted O_3 concentrations that are attributed solely to emissions from oil and gas development. This estimate was calculated by evaluating two CAMx simulations: the base-case simulation, in which all emission categories are accounted, and a "no oil and gas" simulation, which is similar to the base case except that oil and gas emissions are removed. The difference between these two simulations represents the contribution of oil and gas emissions on regional O_3. Notable in Figure 7b is the fact that oil and gas emissions can actually decrease O_3 concentrations at various sites through the process of "NO_x scavenging," in which available O_3 is consumed by reacting with nitric oxide (NO). This effect is most prevalent in the winter, when O_3 concentrations are lower. However, in the summer, the situation is reversed, and warm, stagnant conditions yield an increase in O_3 from oil and gas emissions. Although these impacts appear relatively small (e.g., an increase of a few ppb in the summer), it should be remembered that this period corresponds with seasonally high O_3 concentrations.

CONCLUSIONS

A regional air quality model has been applied to the western United States to investigate the impacts of emissions from oil and gas development on O_3 concentrations. Incremental O_3 increases (8-hr average) ranging from less than 1 to 7 ppb were predicted at several western Class I areas, and a peak incremental O_3 concentration of 10 ppb was simulated in the Four Corners region. This study, although not exhaustive, does indicate a clear potential for oil and gas development to negatively affect regional O_3 concentrations in the western United States, including several treasured national parks and wilderness areas in the Four Corners region. It is likely that accelerated energy development in this part of the country will worsen the existing problem. The formation of O_3 pollution examined here represents a complex phenomenon involving nonlinear physical and chemical processes, uncertain emission inventories, and fine-scale transport in mountainous terrain. These simulations will be refined when updated emission inventories are available from WRAP. Regional air quality modeling requires significant resources but remains the only feasible option for developing emission control strategies that have the potential to reduce O_3 concentrations and protect air quality.

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Ozone Impacts of Natural Gas Development in the Haynesville Shale

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

Introduction

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

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

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

Methods

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

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

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

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

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

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

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

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

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

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

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

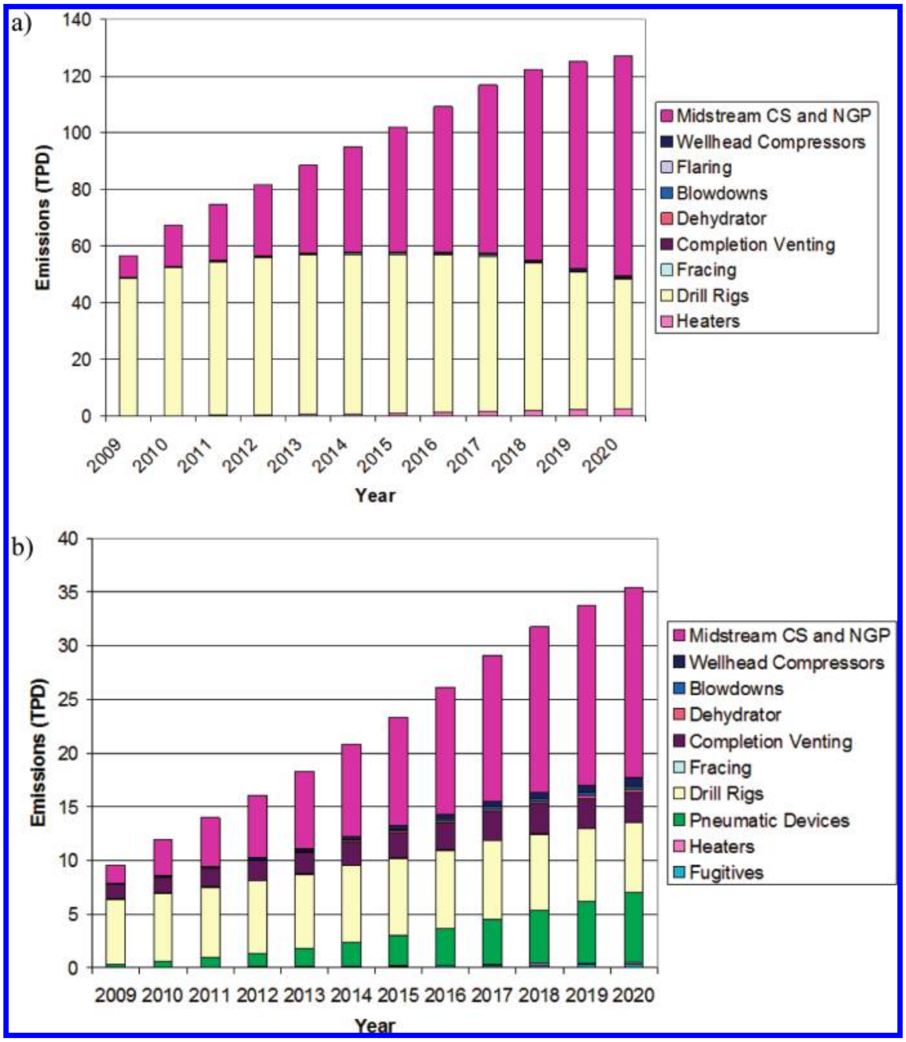

FIGURE 2. a) 2009 to 2020 moderate scenario Haynesville Shale formation-wide NOx emissions by source category and b) 2009 to 2020 moderate scenario Haynesville Shale formation-wide VOC emissions by source category. Midstream CS and NGP refer to central compressor stations (CS) and natural gas processing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

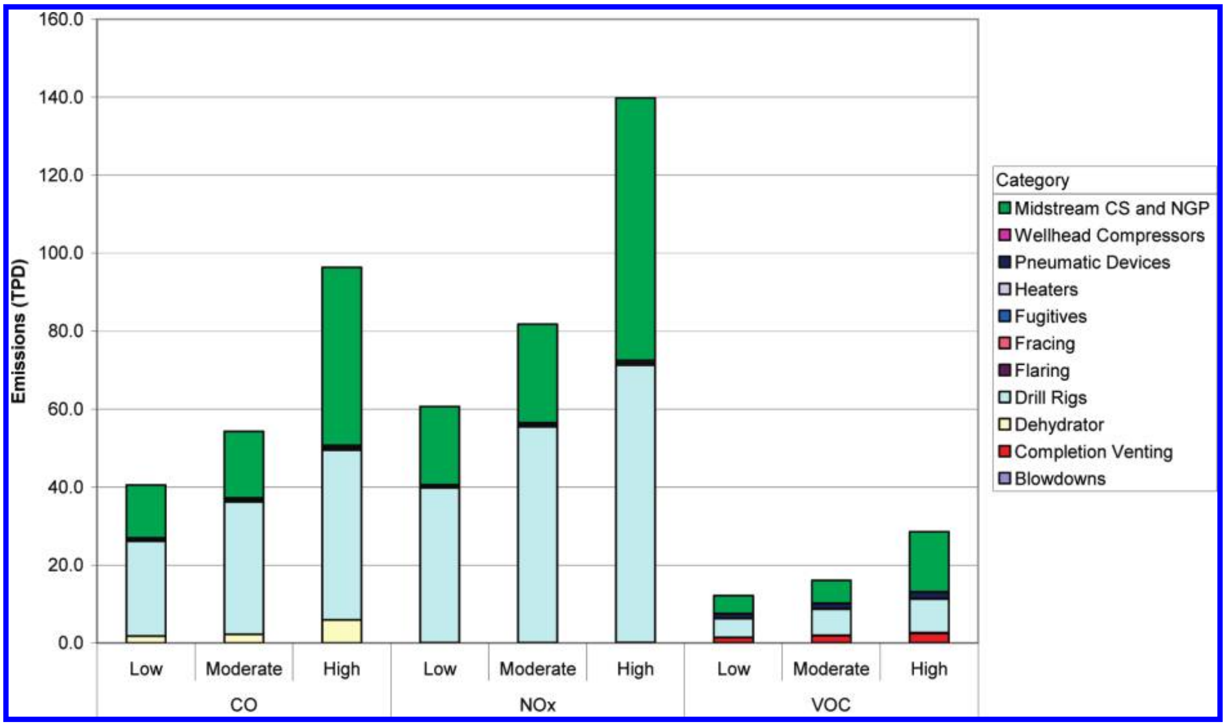

FIGURE 3. 2012 Haynesville Shale formation emissions of NOx, VOC, and CO by scenario and source category. Midstream CS and NGP refer to central compressor stations (CS) and natural gas processing (NGP) facilities which transmit and process produced gas.

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

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

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

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

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

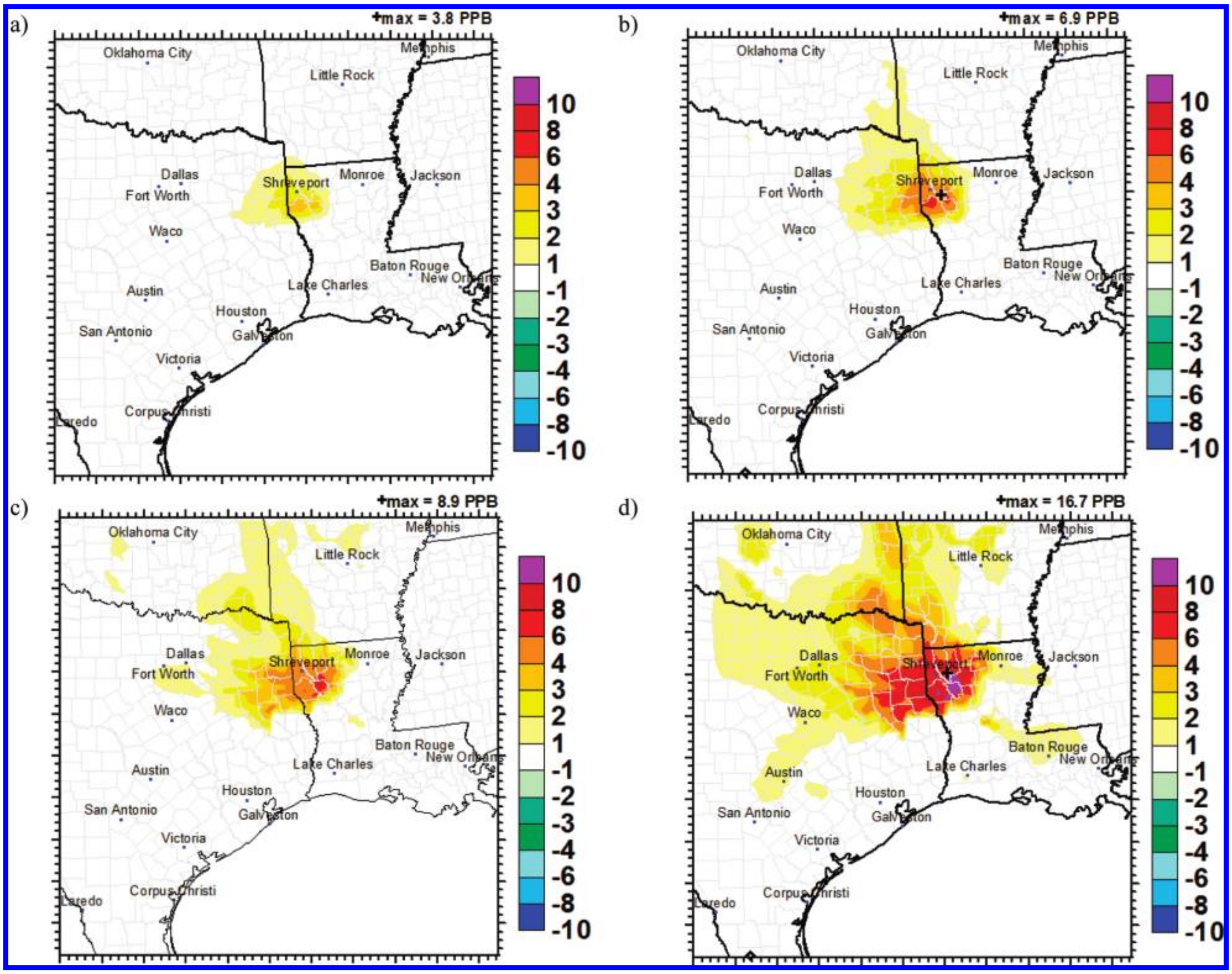

FIGURE 4. Twelve km grid ozone modeling results: a) Episode average difference in daily maximum 8-h ozone (ppb): Haynesville Low Secenario-2012 Baseline and b) Episode average difference in daily maximum 8-h ozone (ppb): Haynesville High Scenario-2012 Baseline and c) Episode maximum difference in daily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

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

Results and Discussion

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

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

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

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

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

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

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

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

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Supporting Information Available

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

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Hormones and Endocrine-Disrupting Chemicals: Low-Dose Effects and Nonmonotonic Dose Responses

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For decades, studies of endocrine-disrupting chemicals (EDCs) have challenged traditional concepts in toxicology, in particular the dogma of "the dose makes the poison," because EDCs can have effects at low doses that are not predicted by effects at higher doses. Here, we review two major concepts in EDC studies: low dose and nonmonotonicity. Low-dose effects were defined by the National Toxicology Program as those that occur in the range of human exposures or effects observed at doses below those used for traditional toxicological studies. We review the mechanistic data for low-dose effects and use a weight-of-evidence approach to analyze five examples from the EDC literature. Additionally, we explore nonmonotonic dose-response curves, defined as a nonlinear relationship between dose and effect where the slope of the curve changes sign somewhere within the range of doses examined. We provide a detailed discussion of the mechanisms responsible for generating these phenomena, plus hundreds of examples from the cell culture, animal, and epidemiology literature. We illustrate that nonmonotonic responses and low-dose effects are remarkably common in studies of natural hormones and EDCs. Whether low doses of EDCs influence certain human disorders is no longer conjecture, because epidemiological studies show that environmental exposures to EDCs are associated with human diseases and disabilities. We conclude that when nonmonotonic dose-response curves occur, the effects of low doses cannot be predicted by the effects observed at high doses. Thus, fundamental changes in chemical testing and safety determination are needed to protect human health. **(*Endocrine Reviews* 33: 0000–0000, 2012)**

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Abbreviations: A4, Androstenedione; AhR, aryl hydrocarbon receptor; BPA, bisphenol A; CDC, Centers for Disease Control and Prevention; DDE, dichlorodiphenyldichloroethylene; DDT, dichlorodiphenyltrichloroethane;DES, diethylstilbestrol; EDC, endocrine-disrupting chemicals; EPA, Environmental Protection Agency; ER, estrogen receptor; FDA, Food and Drug Administration; GLP, good laboratory practices; LOAEL, lowest observed adverse effect level; mER, membrane-associated ER; NHANES, National Health and Nutrition Examination Survey; NIS, sodium/iodide symporter; NMDRC, nonmonotonic dose-response curve; NOEL, no observed effect level; NOAEL, no observed adverse effect level; NTP, National Toxicology Program; PIN, prostatic intraepithelial neoplasias; POP, persistent organic pollutants; ppb, parts per billion; SERM, selective ER modulator; TCDD, 2,3,7,8-tetrachlorodibenzo-*p*-dioxin; WoE, weight of evidence.

I. Introduction

This review focuses on two major issues in the study of endocrine-disrupting chemicals (EDCs): low-dose exposures and nonmonotonic dose-response curves (NMDRCs). These concepts are interrelated, and NMDRCs are especially problematic for assessing potential impacts of exposure when nonmonotonicity is evident at levels of exposure below those that are typically used in toxicological assessments. For clarity of presentation, however, we will first examine each of the concepts separately.

A. Background: low-dose exposure

It is well established in the endocrine literature that natural hormones act at extremely low serum concentrations, typically in the picomolar to nanomolar range. Many studies published in the peer-reviewed literature document that EDCs can act in the nanomolar to micromolar range, and some show activity at picomolar levels.

1. What is meant by low dose?

In 2001, at the request of the U.S. Environmental Protection Agency (EPA), the National Toxicology Program (NTP) assembled a group of scientists to perform a review of the low-dose EDC literature (1). At that time, the NTP panel defined low-dose effects as any biological changes 1) occurring in the range of typical human exposures or 2) occurring at doses lower than those typically used in standard testing protocols, *i.e.* doses below those tested in traditional toxicology assessments (2). Other definitions of low dose include 3) a dose below the lowest dose at which a biological change (or damage) for a specific chemical has been measured in the past, *i.e.* any dose below the lowest observed effect level or lowest observed adverse effect level (LOAEL) (3), or 4) a dose administered to an animal that produces blood concentrations of that chemical in the range of what has been measured in the general human population (*i.e.* not exposed occupationally, and often referred to as an environmentally relevant dose because it creates an internal dose relevant to concentrations of the chemical measured in humans) (4, 5). This last definition takes into account differences in chemical metabolism and pharmacokinetics (*i.e.* absorption, distribution, and excretion of the chemical) across species and reduces the importance of route of exposure by directly comparing similar blood or other tissue concentrations across model systems and experimental paradigms. Although these different definitions may seem quite similar, using just a single well-studied chemical like bisphenol A (BPA) shows how these definitions produce different cutoffs for exposure concentrations that are considered low dose (Table 1). For many chemicals, including EDCs, a large number of studies meet the criteria for low-dose studies regardless of whether the cutoff point for a low dose was based on the range of typical human exposures, doses used in traditional toxicology, or doses that use an internal measure of body burden.

Whether low doses of EDCs influence disease is a question that now extends beyond the laboratory bench, because epidemiological studies show that environmental exposures to these chemicals are associated with disorders in humans as well (see for examples Refs. 6–16). Although disease associations have historically been observed in individuals exposed to large concentrations of EDCs after

TABLE 1. Low-dose definitions and cutoff doses: BPA and DEHP as examples

Chemical	Estimated range of human exposures	Doses below the NOAEL	Doses below the LOAEL	Administered doses (to animals) that produce blood levels in typical humans
BPA	0.4–5 μg/kg · d (679)	No NOAEL was ever established in toxicological studies (38)	<50 mg/kg · d (38)	~400 μg/kg · d to rodents and nonhuman primates (4, 253)
DEHP	0.5–25 μg/kg · d (680)	<5.8 mg/kg · d (681, 682)	<29 mg/kg · d (681, 682)	Unknown

Estimates of human exposure are made from consumer product consumption data but do not take into account that there are unknown sources of these chemicals. DEHP, Bis(2-ethylhexyl) phthalate.

industrial accidents (17–19) or via occupational applications (20–22), recent epidemiological studies reveal links between environmentally relevant low concentrations and disease prevalence. With the extensive biomonitoring studies performed by the U.S. Centers for Disease Control and Prevention (CDC) (23, 24) and similar environmental surveys performed in Europe (25) and elsewhere (www.statcan.gc.ca/concepts/hs-es/measures-mesures-eng.htm), knowledge about environmental exposures to EDCs and their associations with human health disorders has increased substantially.

Low-dose effects have received considerable attention from the scientific and regulatory communities, especially when examined for single well-studied chemicals like BPA (4, 27–32). The low-dose literature as a whole, however, has not been carefully examined for more than a decade. Furthermore, this body of literature has been disregarded or considered insignificant by many (33, 34). Since the NTP's review of the low-dose literature in 2001 (2), a very large body of data has been published including 1) additional striking examples of low-dose effects from exposures to well-characterized EDCs as well as other chemicals, 2) an understanding of the mechanisms responsible for these low-dose effects, 3) exploration of nonmonotonicity in *in vivo* and *in vitro* systems, and 4) epidemiological support for both low-dose effects and NMDRCs.

2. Is the term low dose a misnomer?

Endogenous hormones are active at extremely low doses, within and below the picomolar range for endogenous estrogens and estrogenic drugs, whereas environmental estrogen mimics are typically active in the nanomolar to micromolar range (for examples, see Refs. 35–38), although some show effects at even lower concentrations (39–41). Importantly, the definitions above do not take into account the potency or efficacy of the chemical in question, a topic that will be discussed in greater detail below. Instead, low dose provides an operational definition, in which doses that are in the range of human exposure, or doses below those traditionally tested in toxicological studies, are considered low. To be clear, none of these definitions suggest that a single concentration can be set as a low dose cutoff for all chemicals. Using the above definitions, for some chemicals, low doses could potentially be in the nanogram per kilogram range, but for most chemicals, doses in the traditional micro- and milligram per kilogram range could be considered low doses because traditional approaches to testing chemicals typically did not examine doses below the milligram per kilogram dose range.

B. Background: NMDRCs

We have defined low-dose studies according to the definitions established by the NTP panel of experts (2). However, because the types of endpoints that are typically examined at high doses in toxicological studies are often different from the types of endpoints examined in low-dose studies, one cannot assume that an effect reported in the low-dose range is necessarily different from what would be observed at higher doses. For example, low doses of a chemical could affect expression of a hormone receptor in the hypothalamus, an endpoint not examined in high-dose toxicology testing, and high doses could similarly affect this same endpoint (but are likely to be unreported because high doses are rarely tested for these types of endpoints). Thus, the presence of low-dose effects makes no assumptions about what has been observed at higher concentrations. (As discussed elsewhere, for the majority of chemicals in commerce, there are no data on health effects and thus no established high- or low-dose range.) Therefore, low-dose effects could be observed at the lower end of a monotonic or linear dose-response curve.

In contrast, the definition of a NMDRC is based upon the mathematical definition of nonmonotonicity: that the slope of the dose-response curve changes sign from positive to negative or vice versa at some point along the range of doses examined (42). Often NMDRCs have a U- or inverted U-shape (43); these NMDRCs are thus also often referred to as biphasic dose-response curves because responses show ascending and descending phases in relation to dose. Complex, multiphasic curves have also been observed (41, 44, 45). NMDRCs need not span from true low doses to high (pharmacologically relevant) doses, although experiments with such a broad dose range have been performed for several EDCs; the observation of nonmonotonicity makes no assumptions about the range of doses tested. Examples of NMDRCs from *in vitro* cell culture and *in vivo* animal experiments, as well as epidemiological examples, are presented in detail later in this review (see *Sections III.C.1–3*). Additional examples of NMDRCs are available in studies examining the effects of vitamins and other essential elements on various endpoints (see for example (46); these will not be examined in detail in this review due to space constraints.

NMDRCs present an important challenge to traditional approaches in regulatory toxicology, which assume that the dose-response curve is monotonic. For all monotonic responses, the observed effects may be linear or nonlinear, but the slope does not change sign. This assumption justifies using high-dose testing as the standard for assessing chemical safety. When it is violated, high-dose testing regimes cannot be used to assess the safety of low doses.

It should be noted that both low dose and nonmonotonicity are distinguished from the concept of hormesis, which is defined as a specific type of response whereby "the various points along [the dose response] curve can be interpreted as beneficial or detrimental, depending on the biological or ecological context in which they occur" (47). Estimations of beneficial or adverse effects cannot be ascertained from the direction of the slope of a dose-response curve (48–50). In their 2001 Low Dose Peer Review, the NTP expert panel declined to consider whether any effect was adverse because "in many cases, the long-term health consequences of altered endocrine function during development have not been fully characterized" (2). There are still debates over how to define adverse effects (51–53), so for the purposes of this review, we consider any biological change to be an effect. Importantly, most epidemiological studies are by definition examining low doses (unless they are focusing on occupationally exposed individuals), and these studies typically focus on endpoints that are accepted to be adverse for human health, although some important exceptions exist (54–56).

Finally, it is worth noting that any biological effect, whether it is observed to follow linear relationships with administered dose or not, provides conclusive evidence that an EDC has biological activity. Thus, other biological effects are likely to be present but may remain undetected or unexamined. Many EDCs, including those used as pesticides, were designed to have biological effects (for example, insecticides designed to mimic molting hormone). Thus, the question of whether these chemicals have biological effects is answered unequivocally in their design; the question is what other effects are induced by these biologically active agents, not whether they exist.

C. Low-dose studies: a decade after the NTP panel's assessment

In 2000, the EPA requested that the NTP assemble a panel of experts to evaluate the scientific evidence for low-dose effects and dose-response relationships in the field of endocrine disruption. The EPA proposed that an independent and open peer review of the available evidence would allow for a sound foundation on which the EPA could "determine what aspects, if any, of its standard guidelines for reproductive and developmental toxicity testing [would] need to be modified to detect and characterize low-dose effects" (2). The NTP panel verified that low-dose effects were observed for a multitude of endpoints for specific EDCs including diethylstilbestrol (DES), genistein, methoxychlor, and nonylphenol. The panel identified uncertainties around low-dose effects after exposure to BPA; although BPA had low-dose effects on some endpoints in some laboratories, others were not found to be consistent, leading the panel to conclude that it was "not persuaded that a low-dose effect of BPA has been conclusively established as a general or reproducible finding" (2).

Since the NTP's review of low-dose endocrine disruptor studies, only a few published analyses have reexamined the low-dose hypothesis from a broad perspective. In 2002, R. J. Witorsch (57) analyzed low doses of xenoestrogens and their relevance to human health, considering the different physiologies associated with pregnancy in the mouse and human. He proposed that low doses of endocrine disruptors would not likely affect humans because, although low-dose effects had been observed in rodents, the hormonal milieu, organs controlling hormonal release, and blood levels of estrogen achieved are quite different in humans. There are, of course, differences in hormones and hormone targets between rodents and humans (58), but the view that these differences negate all knowledge gained from animal studies is not supported by evolutionary theory (59–61). This human-centered stance argues against the use of animals for any regulatory testing (62) and runs counter to the similarities in effects of EDCs on humans and animals; rodents proved to be highly predictive of the effects of DES on humans (63, 64). In a striking example, studies from mice and rats predicted that gestational exposure to DES would increase mammary cancer incidence decades before women exposed *in utero* reached the age where this increase in risk was actually observed (65–67).

In 2007, M. A. Kamrin (68) examined the low-dose literature, focusing on BPA as a test case. He suggested that three criteria were required to support the low-dose hypothesis. First is reproducibility, which he defined as "the same results are seen from the same causes each time a study is conducted." Furthermore, he proposed that the dose response for the effects must be the same from study to study. Second is consistency, which he defined as the results all fitting into a pattern, whereby the results collected from multiple species and under variable conditions all show the same effect. And third is proper conduct of studies, which he defined as including the appropriate controls and performance under suitable experimental conditions as well as the inclusion of multiple doses such that a dose-response curve can be obtained.

Although we and others (69–72) agree with the use of these criteria (reproducibility, consistency, and proper experimental design), there are significant weaknesses in the logic Kamrin employed to define these factors. First, suggesting that reproducibility is equivalent to the same results obtained each time a study is conducted is unrealistic and not a true representation of what is required of replication. As has been discussed in other fields, "there is no end to the ways in which any two experiments can be counted as the same — or different . . . All experiments are the same in respect of their being experiments; they are all different by virtue of being done at different places, at different times, by different people, with different strains of rat, training regime, and so on" (73).

Furthermore, according to the Bradford-Hill criteria, a set of requirements accepted in the field of epidemiology to provide adequate evidence of a causal relationship between two factors, a single negative result (or even several studies showing negative results) cannot negate other studies that show adverse effects (74). Essentially, all scientists know that it is very easy for an experiment to find no significant effects due to a myriad of reasons; it is more difficult to actually find effects, particularly when using highly sophisticated techniques (69).

Second, the concept of consistency as a pattern that can be derived from all results is one we will use below, using a weight-of-evidence (WoE) approach and several specific examples. However, Kamrin's proposed idea that every study must show the same effect has the same weaknesses as discussed for the proposed definition of reproducibility and does not acknowledge the obvious differences in many species and strains. It also suggests that the identification of a single insensitive strain could negate any number of positive studies conducted with appropriate animal models (75).

And finally, Kamrin suggested that only studies with appropriate controls should be used for analyses, a criterion we agree should be followed. However, his own scrutiny of the low-dose animal literature fails to do so (68). He also suggested that studies use multiple doses so that a dose-response curve can be obtained. Although studies using a single dose can be informative, we agree that dose-response relationships provide important information to researchers and risk assessors alike. However, this requirement is not helpful if there is an insistence on observing a linear response; as we discuss in depth in this review, there are hundreds of examples of nonmonotonic and other nonlinear relationships between dose and endpoint. These should not be ignored.

In 2004, Hayes (76) reviewed the available literature concerning the effects of atrazine on amphibian development, with a specific focus on the effect of ecologically relevant doses of this EDC on malformations of the gonads and other sexually dimorphic structures; in the case of aquatic exposures, it can be difficult to determine what a cutoff for a low dose would be; thus, Hayes focused on studies examining the effects of atrazine at levels that had been measured in the environment. He reviewed the results produced by several labs, in which it was independently demonstrated that low concentrations of atrazine produced gonadal abnormalities including hermaphroditism, males with extra testes, discontinuous gonads, and other defects. Hayes' work also clearly addressed the so-called irreproducibility of these findings by analyzing the studies that were unable to find effects of the pesticide; he noted that the negative studies had multiple experimental flaws, including contamination of the controls with atrazine, overcrowding (and therefore underdosing) of experimental animals, and other problems with animal husbandry that led to mortality rates above 80%.

In 2006, vom Saal and Welshons (77) examined the low-dose BPA literature, identifying more than 100 studies published as of July 2005 that reported significant effects of BPA below the established LOAEL, of which 40 studies reported adverse effects below the 50 μg/kg · d safe dose set by the EPA and U.S. Food and Drug Administration (FDA); all of these studies would be considered low dose according to the NTP's definition (2). The authors proposed that these examples should be used as evidence to support the low-dose hypothesis. Furthermore, this publication detailed the similarities among the studies that were unable to detect any effects of low doses of BPA and established a set of criteria required to accept negative studies. We have adapted the criteria detailed by Hayes (76) and vom Saal and Welshons (77) to produce a set of requirements for low-dose studies; these criteria are described in some detail below.

D. Why examine low-dose studies now?

The developmental origins of health and disease hypothesis originated from studies showing that fetal DES exposure could cause severe malformations and cancers of the reproductive tract, and other studies demonstrating that fetal malnutrition could lead to adult diseases including metabolic syndrome, diabetes, and increased stroke incidence (78–81). Since that time, the developmental origins of health and disease hypothesis has been extended to address whether diseases that are increasing in prevalence in human populations could be caused by developmental exposures to EDCs (67, 82–85). Evidence from the animal literature has been tremendously informative about the effects of EDC exposures early in development and has driven new hypotheses to be tested in epidemiology studies (86). Studies including several discussed in this review provide supportive evidence that the fetal and neonatal periods are specifically sensitive to chemicals that alter endocrine signaling and that EDCs could be contributing to a range of diseases.

Strong, reliable, and reproducible evidence documents the presence of low concentrations of EDCs and other chemicals in human tissues and fluids, as well as in environmental samples (28, 87–89). These studies indicate that samples collected from humans and the environment typically contain hundreds of contaminants, usually in the parts-per-billion (ppb) range (90, 91). The obvious question with potentially large public health implications is whether these concentrations are so low as to be irrelevant to human health. The fact that epidemiological analyses (reviewed in *Section III.C.3*) repeatedly find associations between the measured concentrations in human samples and disease endpoints suggests it is inappropriate to assume the exposures are too low to matter. That is especially the case given the empirical data (reviewed in *Section II.A*) from animal and cell culture experiments showing effects can be caused by concentrations comparable (and sometimes below) what is measured in humans and also the detection of NMDRCs in some of those same experiments.

In the human biomonitoring field, large databases such as the CDC's National Health and Nutrition Examination Survey (NHANES) have allowed researchers to make comparisons between groups of individuals with various exposure criteria; some of these studies will be addressed in detail in subsequent sections of this review. Although by definition these databases examine low-dose exposures, their use has been the subject of significant debate. Because of the large number of chemicals that have been measured (>300 in the most recent NHANES by the CDC) and the large number of health outcomes and other disease-related data collected from the individuals that donated biological samples, it has been argued that the number of possible associations that could be made would lead to a significant number of false positives (92); thus, associations could be found simply because of extensive data dredging. This has led some to suggest that these studies as a whole should be rejected (93, 94).

In response to these criticisms, epidemiologist Jan Vandenbroucke (95) notes, "researchers do not mindlessly grind out one analysis after another"; the examination of these databases for associations between chemical exposures and health effects does not entail the statistical comparison between all possible factors, calculated as some 8800 comparisons in the CDC's NHANES database (92). Instead, epidemiologists typically focus on a select number of comparisons that address relationships between chemicals and diseases identified *a priori* (96, 97), often because of mechanistic data obtained in laboratory animals or *in vitro* work with human and animal cells and tissues. Repeated findings of links between EDC exposures and diseases in epidemiological analyses of biomonitoring data based on *a priori* hypotheses suggests these relationships should not be rejected as a statistical artifact and, instead, should be the basis for significant concern that low-dose effects can be detected in the general population (85, 98).

E. Mechanisms for low-dose effects

The endocrine system is particularly tuned to respond to very low concentrations of hormone, which allows an enormous number of hormonally active molecules to coexist in circulation (38). As a ligand-receptor system, hormones act by binding to receptors in the cell membrane, cytosol, or the nucleus. The classical effects of nuclear hormone receptors influence gene expression directly, although rapid nongenomic actions at membrane-associated receptors are now well documented and accepted. Membrane receptors are linked to different proteins in the cell, and binding to these receptors typically changes cellular responses in a rapid fashion (99), although the consequence of a rapid signaling event could be the activation of a nuclear transcription factor, leading to responses that take longer to detect. Peptide hormones can also influence gene expression directly (see Refs. 100 and 101 for examples).

There are several means by which the endocrine system displays specificity of responses to natural hormones. Many hormone receptors are expressed specifically in a single or a few cell types (for example, receptors for TSH are localized to the thyroid), whereas some (like thyroid hormone receptors) are found throughout the body (102). For receptors that are found in multiple cell types, different effects are produced in part due to the presence of different coregulators that influence behaviors of the target genes (103–105). And finally, some hormones have multiple receptors [for example estrogen receptor (ER)α and ERβ], which are expressed in different quantities in different cell types and organs and can produce variable effects on gene expression or cellular phenomena (cell proliferation *vs.* apoptosis) (102, 106).

The typical physiological levels of the endogenous hormones are extremely low, in the range of 10–900 pg/ml for estradiol, 300–10,000 pg/ml for testosterone, and 8–27 pg/ml for T_4 (see Table 2). Importantly, steroid hormones in the blood are distributed into three phases: free, representing the unconjugated, unbound form; bioavailable, representing hormones bound to low-affinity carrier proteins such as albumin; and inactive, representing the form that is bound to high-affinity binding proteins such as SHBG or α-fetoprotein (38) (Fig. 1A). When the circulating levels in blood are corrected for the low fraction of the hormones that are not bound to serum binding proteins, the free concentrations that actually bring about effects in cells are even lower, for example 0.1–9 pg/ml for estradiol. Concentrations of active hormones will vary based on the age and physiological status of the individual (*i.e.* plasma testosterone levels are less than 1 ng/ml in male children but increase to approximately 5–7 ng/ml in adulthood; during menses, estradiol levels are typically less than 100

TABLE 2. Ranges of endogenous hormones in humans (from Ref. 108)

Hormone	Free concentration (females)	Total concentration (females)	Free concentration (males)	Total concentration (males)
Cortisol	20–300 ng/ml		20–300 ng/ml	
Estradiol	0.5–9 pg/ml (adult female)	<20 pg/ml (prepubertal) 20–800 pg/ml (premenopausal) <30 pg/ml (postmenopausal)		10–60 pg/ml (adult)
Progesterone		0.2–0.55 ng/ml (prepubertal) 0.02–0.80 ng/ml (follicular phase) 0.90–4 ng/ml (luteal phase) <0.5 ng/ml (postmenopausal)		0.1–0.4 ng/ml (prepubertal) 0.2–2 ng/ml (adult)
Insulin		0–250 pmol/liter		0–250 pmol/liter
GH		2–6 ng/ml		2–6 ng/ml
Prolactin		0–15 ng/ml		0–10 ng/ml
Testosterone	9–150 pg/ml (adult)		0.3–250 ng/ml	
Thyroid hormone	8–30 pg/ml (10–35 pM)		8–30 pg/ml (10–35 pM)	
TSH	0.5–5 μU/ml		0.5–5 μU/ml	

pg/ml, but just before ovulation, they spike to 800 pg/ml; *etc.*) (107, 108). Of course, it should be noted that active concentrations of natural hormones vary somewhat from species to species and can even vary between strains of the same species (109).

There are several reasons why endogenous hormones are able to act at such low circulating concentrations: 1) the receptors specific for the hormone have such high affinity that they can bind sufficient molecules of the hormone to trigger a response, 2) there is a nonlinear relationship between hormone concentration and the number of bound receptors, and 3) there is also a nonlinear relationship between the number of bound receptors and the strongest observable biological effect. Welshons and colleagues (38) describe how hormone concentration influences receptor occupancy: "receptor occupancy is never determined to be linear in relation to hormone concentration . . . At concentrations above the K_d [the dissociation constant for receptor-ligand binding kinetics], saturation of the response occurs first, and then at higher concentrations, saturation of receptors is observed." What this means is that at low doses of hormone, a 10-fold increase in hormone concentration can have a 9-fold increase in receptor occupancy, whereas at high doses of hormone, a 10-fold increase in hormone concentration produces a less than 1.1-fold increase in receptor occupancy (38) (Fig. 1B). Thus, even moderate changes in hormone concentration in the low-dose range can produce substantial changes in receptor occupancy and therefore generate significant changes in biological effects. Welshons *et al.* (38) also note that a near-maximum biological response can be observed without a high rate of receptor occupancy, a situation that was previously termed the spare receptor hypothesis (110, 111); that is, the response mechanism saturates before all of the receptors are saturated. The presence of spare receptors is the basis for saying that these receptor systems are tuned to detect low concentrations that lead to occupancy of 0.1–10% of total receptors. Within this range of low receptor occupancy, there is high proportionality between changes in the free hormone concentration and changes in receptor occupancy, and a change in receptor occupancy by a ligand for the receptor is required to initiate changes in receptor-mediated responses (38).

There are additional reasons why natural hormones are active at low doses: 4) hormones have a strong affinity for their receptors (relative to affinity for other receptors) because many hormones are secreted from a single gland or site in the body but must have effects throughout the body in multiple tissues and 5) blood concentrations of hormones are normally pulsatile in nature, with the release of one hormone often controlled by the pulsatile release of another hormone (112, 113), and both the frequency and the amplitude of pulses modulate the biological response; hormones are also influenced by circadian rhythms, with dramatic differences in hormone secretion depending on the time of day (114, 115).

For many years, the mechanisms by which some environmental chemicals acted at low doses were not well understood. In 1995, the National Research Council appointed the Committee on Hormonally Active Agents in the Environment to address public concerns about the potential for adverse effects of EDCs on human health (116). At the time, work on understanding the mechanisms by which EDCs exert their effects was in its infancy, and in the executive summary, the committee stated, "Lack of knowledge about a mechanism does not mean that a reported effect is unconfirmed or unimportant, nor does demonstration of a mechanism document that the resulting effects are unique to that mechanism or are pervasive

Figure 1.

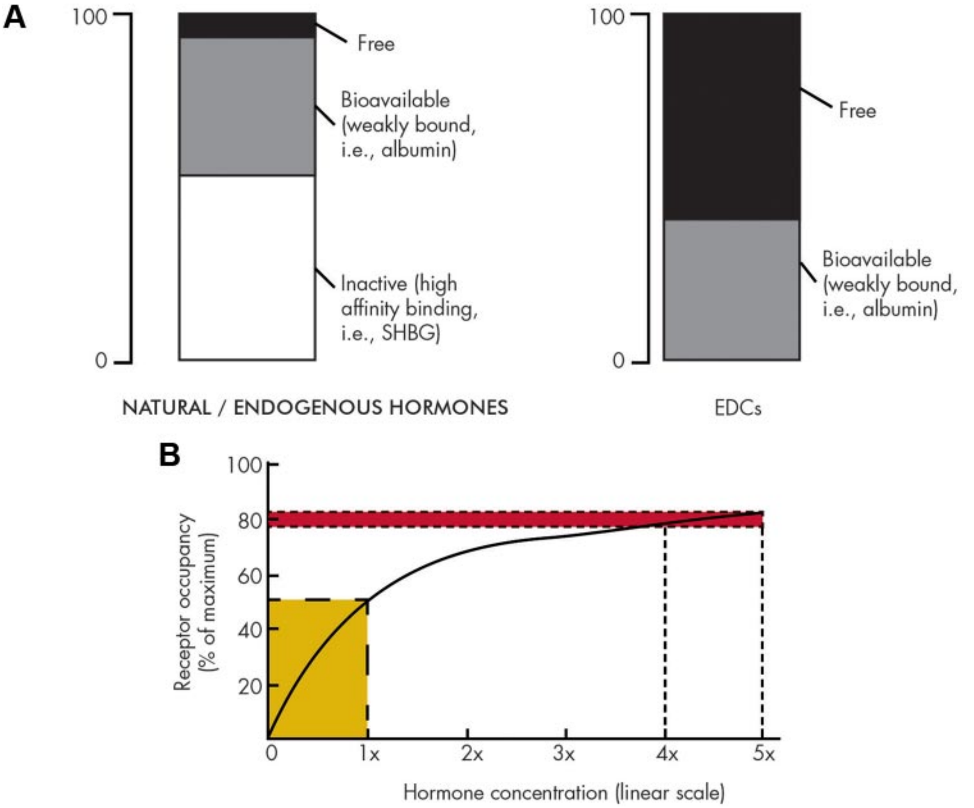

Figure 1. Characteristics and activities of natural hormones. A, This schematic depicts a typical relationship of three phases of circulating hormones: free (the active form of the hormone), bioavailable (bound weakly to proteins such as albumin), and inactive (bound with high affinity to proteins such as SHBG). These three phases act as a buffering system, allowing hormone to be accessible in the blood, but preventing large doses of physiologically active hormone from circulating. With EDCs, there may be little or no portion maintained in the inactive phase. Thus, the entirety or majority of a circulating EDC can be physiologically active; the natural buffering system is not present, and even a low concentration of an EDC can disrupt the natural balance of endogenous hormones in circulation. B, Schematic example of the relationship between receptor occupancy and hormone concentration. In this theoretical example, at low concentrations, an increase in hormone concentration of x (from 0 to 1x) causes an increase in receptor occupancy of approximately 50% (from 0 to 50%, see *yellow box*.) Yet the same increase in hormone concentration at higher doses (from 4x to 5x) causes an increase in receptor occupancy of only approximately 4% (from 78 to 82%, see *red box*).

in natural systems." Since that time, a tremendous amount of work has been dedicated to understanding the molecular mechanisms of action of EDCs, and in particular the mechanisms responsible for low-dose effects.

1. General mechanisms for EDC action

As discussed above, the endocrine system evolved to function when unbound physiologically active ligands (hormones) are present at extremely low doses (117). Because of shared receptor-mediated mechanisms, EDCs that mimic natural hormones have been proposed to follow the same rules and therefore have biological effects at low doses (38, 118). Similarly, EDCs that influence in any way the production, metabolism, uptake, or release of hormones also have effects at low doses, because even small changes in hormone concentration can have biologically important consequences (38, 119).

The estrogen-response mechanisms have been extensively studied with regard to the effects of endogenous estrogens and estrogenic drugs. In classical, genomic estrogen action, when endogenous estrogens bind to ER, those receptors bind to estrogen response element sequences or to a number of other response element sites adjacent to the genes directly responsive to estrogens; this binding influences transcription of estrogen-sensitive genes (120). Xenoestrogens produce the same reactions; these chemicals bind to ERs, which then initiate a cascade of molecular effects that ultimately modify gene expression. Therefore, for the actions of estrogenic EDCs, molecular mechanisms and targets are already known in some detail. Similar mechanisms are induced by the binding of androgens to the androgen receptor, or thyroid hormone agonists to the thyroid hormone receptor, among others.

Additionally, there are EDCs that act as antagonists of these hormone systems, binding to a receptor, but not activating the receptor's typical response, and preventing the binding or activity of the endogenous ligand. Finally, many EDCs bind to the receptor and trigger a response that is not necessarily the same as that triggered by the endogenous estrogens; these are termed selective ER modulators (SERMs). Ultimately, all of these actions occur at the level of the receptor.

Many studies have been dedicated to the understanding of which EDCs bind to which nuclear hormone receptors and how the binding affinities compare to the natural steroid. Thus, many of these chemicals have been classified as weak hormones. Yet studies have shown that, for example, the so-called weak estrogens like BPA can be equally potent as endogenous hormones in some systems, causing biological effects at picomolar levels (30, 38, 41, 121). Both endogenous estrogens and EDCs can bind to ER associated with the cell membrane [membrane-associated ER (mER)α and mERβ] that are identical to the nuclear ER (122–124), and a transmembrane ER called G-protein coupled receptor 30 that is structurally dissimilar to the nuclear ER and encoded by a distinct gene (125, 126). In many cells, 5–10% of total ERα and ERβ are localized to the plasma membrane (124); these membrane-associated receptors are capable of nongenomic steroid action in various cell types (30, 121, 127); thus, rapid and potent effects are well documented for many EDCs including BPA, DES, endosulfan, dichlorodiphenyldichloroethylene (DDE), dieldrin, and nonylphenol, among others (41, 128–130).

Finally, EDCs have other effects that are not dependent on binding to either classical or membrane-bound steroid hormone receptors. EDCs can influence the metabolism of natural hormones, thus producing differences in the amount of hormone that is available for binding either because more (or less) hormone is produced than in a typical system or because the hormone is degraded faster (or slower) than is normal. Other EDCs influence transport of hormone, which can also change the amount of hormone that is available for receptor binding. And EDCs can also have effects that are independent from known endocrine actions. One example is the effect of endogenous hormones and EDCs on ion channel activity. BPA, dichlorodiphenyltrichloroethane (DDT), DES, nonylphenol, and octylphenol have all been shown to disrupt Ca^{2+} channel activity and/or Ca^{2+} signaling in some cell types (131–134). This example illustrates how both natural hormones and EDCs can have hormonal activity via binding to nuclear hormone receptors but may also have unexpected effects via receptor-mediated actions outside of the classical endocrine system.

2. Mechanisms of EDC-induced low-dose actions

The various mechanisms by which EDCs act *in vitro* and *in vivo* provide evidence to explain how these chemicals induce effects that range from altered cellular function, to abnormal organ development, to atypical behaviors. Just as natural hormones display nonlinear relationships between hormone concentration and the number of bound receptors, as well as between the number of bound receptors and the maximal observable biological effect, EDCs obey these rules of binding kinetics (38). Thus, in a way, EDCs exploit the highly sensitive endocrine system and produce significant effects at relatively low doses.

To gain insight into the effects of natural hormones and EDCs on gene expression profiles, it is possible to calculate doses that produce the same effect on proliferation of cultured cells, *i.e.* the quantitative cellular response doses, and determine the effect of those doses on transcriptomal signature profiles. When this is done for estradiol and EDCs with estrogenic properties, the affected estrogen-sensitive genes are clearly different (135). However, an interesting pattern emerges: comparing profiles among only the phytoestrogens shows striking similarities in the genes up- and down-regulated by these compounds; profile comparisons between only the plastic-based estrogens also show similarities within this group. Yet even more remarkable is what occurs when the doses are selected not based on cell proliferation assays but instead on the ability of estradiol and estrogen-mimics to induce a single estrogen-sensitive marker gene. When doses were standardized based on marker gene expression, the transcriptomal signature profiles were very similar between estradiol and estrogen mimics (135). Taken together, these results suggest that the outcomes of these experiments are contextual to the normalization parameter and that marker gene expression and cell proliferation are not superimposable. This indicates that the biological level at which the effects of chemicals are examined (*i.e.* gene expression, cellular, tissue, organ, or organismal) can greatly impact whether low-dose effects are observed and how these effects are interpreted.

There are several other mechanisms by which low-dose activities have been proposed. One such possibility is that low doses of EDCs can influence the response of individuals or organs/systems within the body to natural hormones; thus, the exposed individual has an increased sensitivity to small changes in endogenous steroids, similar to the effects of intrauterine position (see Ref. 136 and *Section I.F*). In fact, several studies have shown that exposure to EDCs such as BPA during perinatal development can influence the response of the mammary gland to estrogen (137, 138) and the prostate to an estrogen-testosterone mixture similar to the concentrations produced in aging men (139–142). There is also evidence that EDCs work additively or even synergistically with other chemicals and natural hormones in the body (143–145). Thus, it is plausible that some of the low-dose effects of an EDC are actually effects of that exogenous chemical plus the effects of endogenous hormone.

Finally, it should be noted that during early development, the rodent fetus is largely, but not completely (146), protected from estrogen via the binding activity of α-fetoprotein, a plasma protein produced in high levels by the fetal liver (147). Some estrogen-like EDCs, however, bind very weakly to α-fetoprotein, and therefore, it is likely that this protein does not provide protection to the fetus during these sensitive developmental periods (36, 148). Furthermore, because EDCs may not bind to α-fetoprotein or other high-affinity proteins in the blood (148–150) and can have a higher binding affinity to proteins like albumin (compared with natural estrogens) (36, 149), the balanced buffer system in place for endogenous hormones may be disturbed (Fig. 1A). Thus, whereas only a portion of endogenous hormones are bioavailable, the entirety of a circulating EDC could be physiologically active.

The effects of hormones and EDCs are dependent on dose, and importantly, low (physiological) doses can be more effective at altering some endpoints compared with high (toxicological) doses. There are many well-characterized mechanisms for these dose-specific effects including signaling via single *vs.* multiple steroid receptors due to nonselectivity at higher doses (30), receptor down-regulation at high doses *vs.* up-regulation at low doses (151, 152), differences in the receptors present in various tissues (153, 154), cytotoxicity at high doses (155), and tissue-specific components of the endocrine-relevant transcriptional apparatus (104, 105). Some of these factors will be addressed in *Section III.B* in the section dedicated to NMDRCs.

F. Intrauterine position and human twins: examples of natural low-dose effects

Hormones have drastically different effects at different periods of development. In a now classical *Endocrinology* paper, Phoenix and colleagues (156) showed that hormone exposures during early development, and in particular fetal development, had organizational effects on the individual, whereby the developing organs were permanently reorganized by exposure to steroids. Permanent, nonreversible masculinization of the developing body plan by androgen exposure *in utero* is an example. These organizational effects are in contrast to the effects of the same hormones, at similar or even higher doses, on adults. The effects of steroids on individuals after puberty have been termed activational, because the effects on target organs are typically transient; withdrawal of the hormone returns the phenotype of the individual to the preexposed state (157), although this is not always the case (158).

One of the most striking examples of the ability of low doses of hormones to influence a large repertoire of phenotypes is provided by the study of intrauterine positioning effects in rodents and other animals. The rodent uterus in particular, where each fetus is fixed in position along a bicornate uterus with respect to its neighbors, is an excellent model to study how hormones released from neighboring fetuses (159) can influence the development of endocrine-sensitive endpoints (31). Importantly, differences in hormonal exposures by intrauterine position are relatively small (see Fig. 2) (160). Thus, even a small magnitude in differences of hormonal exposures is sufficient to generate effects on behavior, physiology, and development.

The earliest studies of intrauterine position compared behavioral characteristics of females relative to their position in the uterus (161–164); male behavior was also affected by intrauterine position (161, 165–167). Subsequent studies of intrauterine position showed that position in the uterus influenced physiological endpoints (157, 160–162, 168–174) as well as morphological endpoints in female rodents (160, 161, 163, 164, 175–177). Male physiology and morphological endpoints were similarly affected by intrauterine position (165, 167, 177–179).

The endocrine milieu of the uterine environment has been implicated in these effects because differences in hormonal exposure have been observed based on intrauterine position (Fig. 2). The production of testosterone in male mice starting at approximately d 12 of gestation allows for passive transfer of this hormone to neighboring fetuses (159, 160, 180). Thus, fetuses positioned between two male neighbors have slightly higher testosterone exposures compared with fetuses positioned between one male and one female or two female neighbors (168, 181–183). These data indicate that very small differences in hormone exposures during fetal development are capable of influencing a variety of endpoints, many of which become apparent only during or after puberty. Furthermore, small differences in hormone exposures may be compounded by other genetic variations such as those normally seen in human populations.

Intrauterine effects have been observed in animals with both large litters and singleton or twin births including ferrets, pigs, hamsters, voles, sheep, cows, and goats (136, 184, 185). But perhaps the most compelling evidence for intrauterine effects comes from human twin studies. Many

Figure 2.

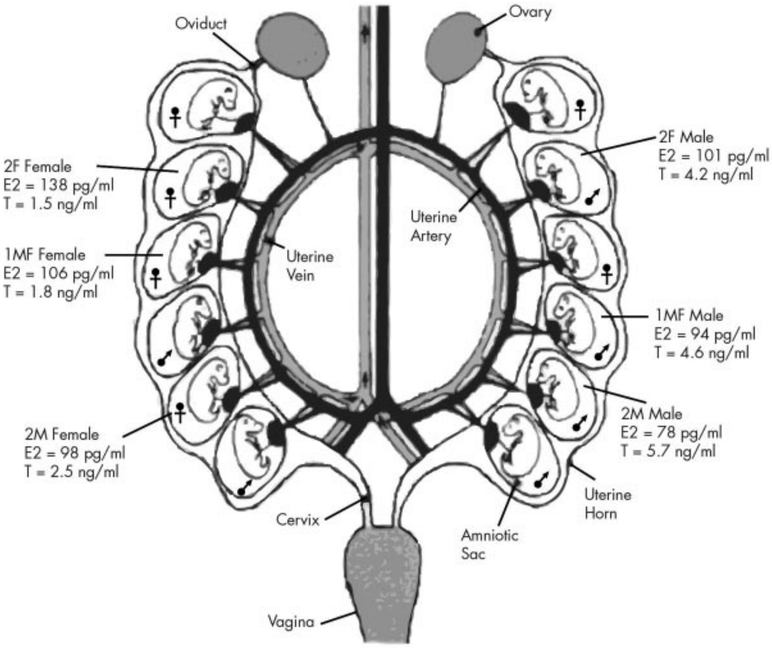

Figure 2. Intrauterine position produces offspring with variable circulating hormone levels. Fetuses are fixed in position in the bicornate rodent uterus, thus delivery via cesarean section has allowed for study of the influence of intrauterine position on behaviors, physiology, and organ morphology. Illustrated here are the differences in estradiol (E2) and testosterone (T) concentrations measured in male and female fetuses positioned between two male neighbors (2M), two female neighbors (2F), or neighbors of each sex (1MF). Direction of blood flow in the uterine artery (dark vessel) and vein (light vessel) is indicated by an *arrow* (159).

studies have found that the sex of the fetuses impacts the phenotype of one or more of the twins, with significant evidence suggesting that male twins strongly influence a female co-twin; endpoints including sensation seeking (186), ear superiority (187, 188), brain and cerebellum volume (189), masculine/feminine behaviors and aggression levels (190–192), handedness (193, 194), reproductive fitness (192, 195), finger length ratios (196), risk for developing eating disorders (197), and birth weight (198) were all affected in females with a male twin. From these studies, many authors have concluded that testosterone from male fetuses influences developmental parameters in female twins; typically, male same-sex twins do not display altered phenotypes for these endpoints. Yet importantly, limited studies indicate that female twins can influence their uterine pairs, with some behaviors affected in male co-twins (191); breast cancer incidence in women and testicular cancer in men have also been shown to be influenced by having a female co-twin (83, 199, 200).

Although the mechanisms for these intrauterine effects are not completely understood, very small differences in hormone exposures have been implicated, making the effects of twin gestations a natural example of low-dose phenomena. In the human fetus, the adrenals produce androgens that are converted to estrogen by the enzyme aromatase, specifically in the placenta. In a human study designed to compare hormone levels in the amniotic fluid, maternal serum, and umbilical cord blood of singleton male and female fetuses, significant differences were observed in the concentrations of testosterone, androstenedione (A4), and estradiol (201). Specifically, amniotic fluid concentrations of testosterone and A4 were approximately twice as high in male fetuses, whereas estradiol concentrations were slightly, but significantly, higher in female fetuses. Yet, interestingly, there were no differences for any of the hormones in maternal serum, similar to findings in mice that litters with a high proportion of males or females did not impact testosterone, estradiol, or progesterone serum levels in mothers (180). In umbilical cord serum, concentrations of A4 and estradiol were higher in males compared with females (201), although it must be noted that these samples were collected at parturition, long after the fetal period of sexual differentiation of the reproductive organs.

Several studies have specifically compared steroid hormone levels in maternal and umbilical cord blood samples collected from same-sex and opposite-sex twins. Male twins, whether their co-twin was a male or a female, had higher blood concentrations of progesterone and testosterone compared with female twins (202). Furthermore, for both sexes, dizygotic twins had higher levels of these hormones, as well as estradiol, compared with monozygotic twins. Fetal sex had no effect on maternal concentrations of testosterone, progesterone, or estrogen, suggesting that any differences observed in fetal samples are due to contributions from the fetuses' own endocrine systems and the placental tissue (203). Yet an additional study conducted in women carrying multiple fetuses (more than three) indicates that both estradiol and progesterone concentrations in maternal plasma increase with the number of fetuses, and when fetal reduction occurs, these hormone levels remain elevated (204).

It has been proposed that low-dose effects seen in different intrauterine positions in litter-bearing animals could be an evolutionary adaptation, whereby the genotypes of the fetuses are relatively similar but a range of phenotypes can be produced via differential hormone exposures (136, 168). For example, female mice positioned between two females are more docile and thus have better reproductive success when resources are plentiful, but females positioned between two males are more aggressive and therefore are more successful breeders under stressful conditions (161, 171, 175). In this way, a mother produces offspring with variable responses to environmental conditions, increasing the chances that her own genetic material will continue to be passed on. Yet although there is evidence to suggest that a variable intrauterine environment is essential for normal development (171), intrauterine positional effects appear to have little effect on offspring phenotypes in inbred rodent strains (168, 205). This result may be related to the link between genetic diversity and hormone sensitivity (206, 207), suggesting that outbred strains are the most appropriate for studying endocrine endpoints and are also most similar to the effects of low doses of hormones on human fetuses.

Finally, it has been proposed that similar mechanisms are used by the developing fetus in response to natural hormones via intrauterine position and EDCs with hormonal activity (136). To this end, several studies have examined the effects of both exposure to an EDC and intrauterine position or have considered the effect of intrauterine position on the response of animals to these chemicals (174, 176, 181, 208, 209). For example, one study found that intrauterine position affected the morphology of the fetal mammary gland, yet position-specific differences were obliterated by BPA exposure (176). Additional studies suggest that prostate morphology is disrupted by 2,3,7,8-tetrachlorodibenzo-*p*-dioxin (TCDD) exposure in males positioned between two females, but this chemical does not affect prostate morphology in males positioned between two males (181). Finally, male rodents positioned between two males have higher glucose intolerance than males positioned between two females, yet when these males are given a diet high in phytoestrogens, glucose tolerance is dramatically improved in the males positioned between two males, whereas their siblings positioned between two females do not benefit (209). What is clear from these studies is that low doses of natural hormones are capable of altering organ morphology, physiology, and reproductive development, similar to the effects of EDCs.

It has been suggested that the endocrine system allows for homeostatic control and that the aim of the endocrine system is to "maintain normal functions and development in the face of a constantly changing environment" (210). Yet studies from intrauterine position, together with studies of EDCs (see *Sections II.C–F*), clearly indicate that the fetal endocrine system cannot maintain a so-called homeostasis and is instead permanently affected by exposures to low doses of hormones.

II. Demonstrating Low-Dose Effects Using a WoE Approach

A. Use of a WoE approach in low-dose EDC studies

In 2001, the NTP acknowledged that there was evidence to support low-dose effects of DES, genistein, methoxychlor, and nonylphenol (2). Specifically, the NTP expert panel found that there was sufficient evidence for low-dose effects of DES on prostate size; genistein on brain sexual dimorphisms, male mammary gland development, and immune responses; methoxychlor on the immune system; and nonylphenol on brain sexual dimorphisms, thymus weight, estrous cyclicity, and immune responses. Using the NTP's definitions of low dose (*i.e.* effects occurring in the range of typical human exposures or occurring at doses lower than those typically used in standard testing protocols), we propose that most if not all EDCs are likely to have low-dose effects. Yet an important caveat of that statement is that low-dose effects are expected for particular endpoints depending on the endocrine activity of the EDC, and not for any/all endocrine-related endpoints. For example, if a chemical blocks the synthesis of a hormone, blood levels of the hormone are expected to decline, and the downstream effects should then be predicted from what is known about the health effects of low hormone levels. In contrast, if a chemical binds a hormone receptor, the effects are expected to be very complex and to be both tissue specific and dose specific. Finally, most EDCs interact with multiple hormone pathways, or even multiple hormone receptors, making the expected effects even more complex and context specific (211–213).

Table 3 summarizes a limited selection of chemicals that have evidence for low-dose effects, with a focus on *in vivo* animal studies. As seen by the results presented in this table, low-dose effects have been observed in chemicals from a number of classes with a wide range of uses including natural and synthetic hormones, insecticides, fungicides, herbicides, plastics, UV protection, and other industrial processes. Furthermore, low-dose effects have been observed in chemicals that target a number of endocrine endpoints including many that act as estrogens and antiandrogens as well as others that affect the metabolism, secretion, or synthesis of a number of hormones. It is also clear from this table that the cutoff for low-dose effects is not only chemical specific but also can be effect dependent. And finally, although this table is by no means comprehensive for all EDCs or even the low-dose effects of any particular chemical, the affected endpoints cover a large range of endocrine targets.

Several EDCs have been well studied, and the number of publications focusing on low-dose effects on a particular developmental endpoint is high; however, other

TABLE 3. EDCs with reported low-dose effects in animals (or humans, where stated)

Chemical	Use	EDC action	Low-dose cutoff	Affected endpoint	Refs.
Aroclor 1221 (PCB mixture)	Coolants, lubricants, paints, plastics	Mimics estrogens, antiestrogenic activity, *etc.*	0.1–1 mg/kg (produces human blood levels)	Brain sexual dimorphisms	683, 684
Atrazine	Herbicide	Increases aromatase expression	200 μg/liter (334, 335)	Male sexual differentiation/development	See this review
BPA	Plastics, thermal papers, epoxy resins	Binds ER, mER, ERRγ, PPARγ, may weakly bind TH receptor and AR	400 μg/kg · d (produces human blood concentrations)	Prostate, mammary gland, brain development and behavior, reproduction, immune system, metabolism	See this review
Chlordane	Insecticide	Binds ER	100 ng/g (produces human blood levels)	Sexually dimorphic behavior	685
Chlorothalonil	Fungicide, wood protectant	Aromatase inhibitor	164 μg/liter (environmental concentrations, EPA)	Corticosterone levels (amphibians)	686
Chlorpyrifos	Insecticide	Antiandrogenic	1 mg/kg · d (EPA)	Acetylcholine receptor binding (brain)	687
DDT	Insecticide	Binds ER	0.05 mg/kg (EPA)	Neurobehavior	688
DES	Synthetic hormone	Binds ER	0.3–1.3 mg/kg · d (dose typically administered to pregnant women)	Prostate weight	689
Dioxin (TCDD)	Industrial byproduct	Binds AhR	1 μg/kg · d (397)	Spermatogenesis, immune function and oxidative stress, tooth and bone development, female reproduction, mammary gland, behavior	See this review
Genistein	Phytoestrogen	Binds ER	50 mg/kg (EPA)	Brain sexual dimorphisms	690
Heptachlor	Insecticide	Induces testosterone hydroxylases	0.15 mg/kg · d (EPA)	Immune responses	691
Hexachlorobenzene	Fungicide	Modulates binding of ligand to TRE, weakly binds AhR	0.08 mg/kg · d (EPA)	Anxiety and aggressive behaviors	692
Maneb	Fungicide	Inhibits TSH release, may bind PPARγ	5 mg/kg · d (EU Commission)	Testosterone release	693
Methoxychlor	Insecticide	Binds ER	5 mg/kg · d (WHO)	Immune system	694, 695
4-Methylbenzylidine camphor	UV screen	Weakly estrogenic	10 mg/kg · d (Europa)	Sexual behavior	696
Methyl paraben	Preservative	Estrogenic	1000 mg/kg · d (EFSA)	Uterine tissue organization	697
Nicotine	Natural alkaloid in tobacco	Binds acetylcholine receptors, stimulates epinephrine	Human use of nicotine substitutes	Incidence of cryptorchidism (humans)	698
Nonylphenol	Detergents	Weakly estrogenic	15 mg/kg · d (EPA)	Testosterone metabolism	699
Octylphenol	Rubber bonding, surfactant	Weakly binds ER, RXR, PRGR	10 mg/kg · d (700)	Testes endpoints	701
Parathion	Insecticide		0.2 mg/kg · d (WHO)	Cognitive and emotional behaviors	702
PBDE-99	Flame retardant	Alters TH synthesis	0.3 mg/kg · d (EPA)	TH levels in blood	703
PCB180	Industrial lubricant, coolant	Impairs glutamate pathways, mimics estrogen	Examined normal human populations	Diabetes (humans)	704
PCB mixtures	Coolants, lubricants, paints, plastics	Binds AhR, mimic estrogens, antiestrogenic activity, etc.	Each at environmentally relevant levels	TH levels	705
Perchlorate	Fuel, fireworks	Blocks iodide uptake, alters TH	0.4 mg/kg · d (436)	TSH levels (humans)	See this review
Sodium fluoride	Water additive (to prevent dental caries), cleaning agent	Inhibits insulin secretion, PTH, TH	4 mg/liter water (EPA standard)	Bone mass and strength	706
Tributyltin oxide	Pesticide, wood preservation	Binds PPARγ	0.19 mg/kg · d (EPA)	Obesity	707
Triclosan	Antibacterial agent	Antithyroid effects, androgenic and estrogenic activity	12 mg/kg · d (Europe SCCP)	Altered uterine responses to ethinyl estradiol	708
Vinclozolin	Fungicide	Antiandrogenic	1.2 mg/kg · d (EPA)	Male fertility	709

EDC action indicates that for some chemicals, an effect is observed (*i.e.* estrogenic, androgenic), but for many EDCs, complete details of receptor binding are unavailable or incomplete. Low-dose cutoff means the lowest dose tested in traditional toxicology studies, or doses in the range of human exposure, depending on the data available. Affected endpoint means at least one example of an endpoint that shows significant effects below the low-dose cutoff dose. This list is not comprehensive, and the lack of an endpoint on this table does not suggest that low doses do or do not affect any other endpoints. AR, Androgen receptor; EFSA, European Food Safety Authority; ERR, estrogen related receptor; PCB, polychlorinated biphenyl; PPARγ, peroxisome proliferator-activated receptor-γ; PRGR, progesterone receptor; RXR, retinoid X receptor; SCCP, Scientific Committee on Consumer Products; TH, thyroid hormone; TRE, thyroid response element; WHO, World Health Organization.

chemicals are less well studied with fewer studies pointing to definitive low-dose effects on a given endpoint. In fact, there are a significant number of EDCs for which high-dose toxicology testing has been performed and the no observed adverse effect level (NOAEL) has been derived, but no animal studies in the low-dose range have been conducted, and several hundred additional EDCs where no significant high- or low-dose testing has been performed (see Table 4 for examples). Balancing the large amount of data collected from some well-studied chemicals like BPA and atrazine with the relative paucity of data about other chemicals is a difficult task.

TABLE 4. Select examples of EDCs whose potential low-dose effects on animals remain to be studied

Chemical	Use	EDC action	Low-dose cutoff
Antiseptics and preservatives			
Butyl paraben	Preservative (cosmetics)	Estrogenic, antiandrogenic	2 mg/kg · d (EPA)
Propyl paraben	Antimicrobial preservative found in pharmaceuticals, foods, cosmetics, and shampoos	Estrogenic activity	LOAEL 10 mg/kg · d, NOEL 6.5 mg/kg · d (Europa)
Cosmetics and personal care products			
2,4-Dihydroxybenzophenone	UV absorber in polymers, sunscreen agent	Estrogenic activity	Not identified
3-Benzylidene camphor	UV blocker used in personal care products	Estrogenic activity	0.07 mg/kg · d (710)
4,4′-Dihydroxybenzophenone	UV light stabilizer used in plastics, cosmetics, adhesives, and optical fiber	Estrogenic activity	Not identified
Benzophenone-2	Used in personal care products such as aftershave and fragrances	Estrogenic activity, changes in T_4, T_3, and TSH levels, alterations in cholesterol profile	NOEL 10–333 mg/kg · d (711)
Benzophenone-3	UV filter	Estrogenic, PPARγ activator	200 mg/kg · d (Europa)
Multiple use (other)			
Melamine	Flame-retardant additive and rust remover; used to make laminate, textile, and paper resins; metabolite of cyromazine	Affects voltage-gated K^+ and Na^+ channels and Ca^{2+} concentrations in hippocampal neurons	63.0 mg/kg · d (FDA)
Resorcinol	Used in the manufacturing of cosmetics, dyes, flame retardants, hair dye formulations, pharmaceuticals, skin creams, and tires	Alters T_4 and TSH levels	80.00 mg/kg · d (Europa)
Pesticides			
Aldrin[a]	Insecticide	Estrogenic activity	0.025 mg/kg · d (Health Canada)
Alachlor	Herbicide	Decreases serum T_4, binds PR, weakly binds ER	1 mg/kg · d (EPA)
Amitrole	Herbicide	Decreases thyroid hormone	0.12 mg/kg · d (FAO)
Bitertanol	Fungicide	Alters aromatase	30 mg/kg · d (EPA)
Carbendazim	Fungicide	Affects FSH, LH, and testosterone levels; alters spermatogenesis and Sertoli cell morphology	8 mg/kg · d (712)
Diazinon	Insecticide	Alters glucocorticoids	0.065 mg/kg · d (CDC)
Endrin[a]	Insecticide	Stimulates glucocorticoid receptor	0.025 mg/kg · d (CDC)
Fenoxycarb	Insecticide	Alters acetylcholinesterase	260 mg/kg · d (CDC)
Mirex[a]	Insecticide	Decreases testosterone levels	0.075 mg/kg · d (CDC)
Zineb	Fungicide	Alters T_4 and dopamine levels	LOAEL 25 mg/kg · d (EPA)
Ziram	Fungicide	Alters norepinephrine levels	1.6 mg/kg · d (EPA)
Resins			
Bisphenol F	Used in polycarbonates	Alters T_4, T_3, and adiponectin levels, has estrogenic activity	LOAEL 20 mg/kg · d (713)
Styrene	Precursor to polystyrene	Alters dopamine	200 mg/kg · d (EPA)

PPARγ, peroxisome proliferator-activated receptor-γ; PR, progesterone receptor.

[a] These chemicals were identified in the 1990s as part of the dirty dozen, 12 chemicals that were acknowledged to be the worst chemical offenders because of their persistence in the environment, their ability to accumulate through the food chain, and concerns about adverse effects of exposures to wildlife and humans. These chemicals were banned by the Stockholm convention and slated for virtual elimination. Yet there is still very little known about the low-dose effects of these chemicals, likely in the range of past and current human and/or wildlife exposures.

WoE approaches have been used in a large number of fields to determine whether the strength of many publications viewed as a whole can provide stronger conclusions than any single study examined alone. Although the term, weight of evidence, is used in public policy and the scientific literature, there is surprisingly little consensus about what this term means or how to characterize the concept (214). Historically, risk assessors have used qualitative approaches (*i.e.* professional judgment to rank the value of different cases) and quantitative approaches (*i.e.* scoring methods to produce statistical and mathematical determinations of chemical safety), but it has been argued that these methods lack transparency and may produce findings that are unrepeatable from one risk assessor to another (215, 216). Whatever the method used, when EDCs are being assessed, it is important to use the principles of endocrinology to establish the criteria for a WoE approach. We do this in *Section II.B*, identifying three key criteria for determining whether a study reporting no effect should be incorporated into a WoE approach. It also should be noted that in epidemiology, the term, weight of evidence, is typically not used, but the concept is actuated by meta-analysis, formally and quantitatively combining data across studies, including a plot of individual and pooled study findings and also a measure of heterogeneity of findings between studies.

For some well-studied chemicals, there are large numbers of studies showing both significant effects, and additional studies showing no effects, from low-dose exposures. In these cases, extensive work is needed to deal with discordant data collected from various sources; studies showing no effect of low-dose exposures must be balanced in some way with those studies that do show effects. As stated by Basketter and colleagues (217), "it is unwise to make a definitive assessment from any single piece of information as no individual assay or other assessment . . . is 100% accurate on every occasion . . . This means that from time to time, one piece of conflicting data has to be set aside." WoE approaches in EDC research have typically dealt with datasets that have some conflicting studies, and these conflicts are even more difficult to sort out when studies have attempted to directly replicate published findings of adverse effects (see for example Refs. 218–221).

Most previously published WoE analyses have examined chemicals broadly (asking questions such as, "Does BPA produce consistent adverse effects on any endpoint?") (see Ref. 222). This can lead to problems including those encountered by the NTP expert panel, which found that there was some evidence for low-dose effects of BPA on certain endpoints but mixed findings for other endpoints. For example, the panel noted that some studies found low-dose effects of BPA on the prostate, but other studies could not replicate these findings. In *Section II.B*, we address criteria that are needed to accept those studies that are unable to detect low-dose effects of chemicals; these criteria were not used by the NTP in 2001, but they are essential to address controversies of this sort and perform WoE analyses using the best available data. In the sections that follow, we employed a WoE approach to examine the evidence for low-dose effects of single chemicals on selected endpoints or tissues, also paying attention to when in development the EDC in question were administered.

B. Refuting low-dose studies: criteria required for acceptance of studies that find no effect

Over the past decade, a variety of factors have been identified as features that influence the acceptance of low-dose studies (69, 71, 76, 77, 90, 205, 223, 224). In fact, the NTP low-dose panel itself suggested that factors such as strain differences, diet, caging and housing conditions, and seasonal variation can affect the ability to detect low-dose effects in controlled studies (2). In particular, three factors have been identified; when studies are unable to detect low-dose effects, these factors must be considered before coming to the conclusion that no such effects exist.

1. Negative controls confirm that the experimental system is free from contamination

Although all scientific experiments should include negative (untreated) controls, this treatment category is particularly important for EDC research. When a study fails to detect low-dose effects, the observed response in control animals should be compared with historical untreated controls; if the controls deviate significantly from typical controls in other studies, it may indicate that these animals were, in fact, treated or contaminated in some way or that the endpoint was not appropriately assessed (77, 205, 225). For example, if an experiment was designed to measure the effect of a chemical on uterine weight, and the control uteri have weights that are significantly higher than is normally observed in the same species and strain, these animals may have been inadvertently exposed to an estrogen source, or the uteri may not have been dissected properly by the experimenters. In either case, the study should be examined carefully and likely cannot be used to assess low-dose effects; of course, untreated controls should be monitored constantly because genetic drift and changes in diet and housing conditions can also influence these data, thus explaining changes from historical controls. Importantly, several types of contamination have been identified in studies of EDCs including the leaching of chemicals from caging or other environmental sources (226, 227), the use of pesticide-contaminated control sites for wildlife studies and contaminated controls in laboratory studies (76), and even the use of food that interferes with the effects of EDCs (224, 228). It is also important to note that experiments must consider the solvent used in the administration of their test chemical, and thus good negative controls should test for effects of the solvent itself. Using solvent negative controls helps prevent false positives as well as the possibility that the vehicle could mask the effects of the chemical being studied.

2. Positive controls indicate that the experimental system is capable of responding to low doses of a chemical acting on the same pathway

Many studies do not include a positive control, either because of the size and cost of the experiment when including an additional treatment or because an appropriate positive control has not been identified for the endpoint being examined. If the experiment detects an effect of the chemical in question, the exclusion of a positive control does not necessarily affect the interpretation of the results; instead, it can be appropriately concluded that the test chemical is significantly different from unexposed (but similarly handled/treated) negative controls. However, if the study fails to detect low-dose effects of a test chemical, no convincing conclusion can be made; in this case, a positive control is required to demonstrate that the experimental system was capable of detecting such effects (71, 75, 77, 205).

Several issues must be considered when addressing whether the positive control confirms the sensitivity of the assay. First, an appropriate chemical must be selected, and it must be administered via the appropriate route, *i.e.* if the test chemical is administered orally, a positive control that is orally active, such as ethinyl estradiol, should be used; if the test chemical is administered sc, a positive control that is active via this route, such as 17β-estradiol, is most appropriate. The use of 17β-estradiol in studies that use oral exposures is particularly inappropriate (see Ref. 229) for example) because this hormone, like most natural steroids, has very low oral activity (77). Second, the positive control chemical must be examined, and effective, at appropriately low doses. Thus, if the test chemical is 100 times less potent than the positive control, a dose of the positive control 100 times lower than the test compound must produce effects (69, 71, 205). For example, studies that report effects of ethinyl estradiol only at doses that are hundreds of times higher than the dose that is effective in contraceptives (230) are not capable of detecting low-dose effects of test chemicals. Without appropriate and concurrent positive and negative controls, studies that fail to detect low-dose effects of test chemicals should be rejected.

3. Species and animal strains that are responsive to EDCs must be used

The NTP expert panel specifically noted that "because of clear species and strain differences in sensitivity, animal-model selection should be based on responsiveness to endocrine-active agents of concern (*i.e.* responsive to positive controls), not on convenience and familiarity" (2). An analysis of the BPA literature clearly showed that many of the studies that failed to detect effects of low doses used the Charles River Sprague-Dawley rat (75); this strain was specifically bred to have large litters (231), and many generations of inbreeding have rendered the animal relatively insensitive to estrogens (205). The NTP expert panel noted the lack of effects of BPA on Sprague-Dawley rats and concluded that there were clear differences in strain sensitivity to this chemical (2). Importantly, this may not be true for Sprague-Dawley rats that originate from other vendors, indicating that animal origin can also influence EDC testing.

Many studies in mice (138, 206, 207, 232–234) and rats (232, 235–239) have described differences displayed between two (or more) animal strains to a natural hormone or EDC. Often these differences can be traced to whether a strain is inbred or outbred. Genetically diverse strains are generally found to be more sensitive to estrogens (206). Importantly, well-controlled studies demonstrate that strain differences in response to estrogen treatment may be organ dependent or may even differ between levels of tissue organization within the same organ. For example, the Sprague-Dawley rat is more sensitive to ethinyl estradiol than other strains when measured by uterine wet weight. However, when other endpoints were measured, *i.e.* height of cells in the uterine epithelium, the Sprague-Dawley rat was indistinguishable from the DA/Han rat; instead, the Wistar rat had the most heightened response (237). Additionally, there are data to indicate that strain differences for one estrogen may not be applicable for all estrogenic chemicals. In comparing the responses of DA/Han, Sprague-Dawley, and Wistar rats to other xenoestrogens, additional differences were observed including a greater increase in uterine wet weight of DA/Han and Sprague-Dawley rats but not Wistar rats after exposure to 200 mg/kg BPA; increased uterine epithelium thickness was observed in Wistar and Sprague-Dawley rats but not DA/Han rats after exposure to 200 mg/kg octylphenol (237). Attempts have been made, at times successfully, to map the differences in strain response to genetic loci (240). However, it appears that strains with differences in response that manifest in some organs do not have divergent responses in other organs, a phenomenon that is not explained by genetic differences alone. For these reasons, the NTP's recommendation that scientists use animals that are proven responsive to EDCs (2) must be observed.

4. Additional factors?

Additional factors have also been identified as influential in the ability (or inability) to detect low-dose effects in

EDC studies. Although these factors must be considered when interpreting studies and using a WoE approach, some issues that were previously identified as essential factors in the design of studies (*i.e.* route of administration) have more recently been disputed (241).

The first factor is the use of good laboratory practices (GLP) in the collection of data. When assessing the EDC literature for risk assessment purposes, the FDA and European Food Safety Authority (EFSA) have given special prominence to studies that complied with GLP guidelines, essentially giving scientific priority to industry-funded studies because that group typically conducts GLP guideline studies (33, 242). Because GLP guidelines are designed only to control data collection, standards for animal care, equipment, and facility maintenance, and they do not ensure that studies were designed properly with the appropriate controls, it has been argued that the use of GLP methods is not appropriate or required for EDC studies (69).

GLP studies are typically large, with dozens of animals studied for each endpoint and at each time point. Thus, it has been concluded that these studies are better simply because they are larger. Yet small studies designed with the use of power analysis, statistical tools that allow researchers to determine *a priori* the number of animals needed to determine significant differences based on effect size, are equally capable of detecting effects while reducing the number of animals used (69). GLP studies also typically (but not necessarily) rely upon standardized assays, which are not generally considered contemporary tools and are often shown to be incapable of detecting adverse effects on endpoints that employ modern tools from molecular genetics and related disciplines. Furthermore, some fields of EDC research have no GLP studies (243). Finally, there is no published evaluation of whether studies performed under GLP are more capable of providing accurate results. The priority given to GLP studies therefore does not appear to have been justified based on any comparative analysis. Thus, as long as studies include appropriate measures of quality assurance, they need not be performed under GLP standards to provide reliable and valuable information, and many GLP studies are inadequate to assess important and relevant endpoints. Instead, the most valuable studies consider the factors presented above, along with appropriate dose selections and choice of endpoint.

The second factor worth considering is the source of funding for studies. In several fields, significant controversy has been produced based on the results obtained from independent scientists compared with results obtained from scientists affiliated with the chemical industry (75, 76). Funding source *per se* should not dictate the outcome of a research study, but that does not mean that researchers are not subject to underlying biases. In our own WoE analyses, presented in *Sections II.C–G*, we do not discount studies merely because they were conducted with industry funds, nor do we lend higher weight to studies conducted in independent or government laboratories; if a study, regardless of funding, finds no effect of a chemical, it is given weight only if the three criteria described in *Sections II.B.1–3* (successful and appropriate negative and positive controls and appropriate choice of animal model) were met.

To perform a WoE evaluation, we identified some basic information about the chemical in question, the dose that would be considered a low-dose cutoff, and the studies in support of and against low-dose effects. We then considered whether the majority of studies found effects of low doses of a chemical on a single endpoint in question. If studies did not find low-dose effects, we considered whether they adhered to the criteria discussed above for proper design of an EDC low-dose study. In particular, we considered whether appropriate animal strains as well as positive and negative controls were used. With regard to animal strain, as discussed briefly in *Section II.B.3*, there is variability between animal strains that can significantly influence the ability to detect effects of EDCs; using insensitive strains to produce negative data cannot refute positive data in a sensitive strain. In several cases, it was easy to conclude that there was a strong case for low-dose effects because there were no studies finding no effects at low doses or because all of the negative studies were inappropriately designed. For other chemicals, a significant number of studies found effects on the endpoint being considered, but other (adequately designed) studies refuted those findings. Under those circumstances, we determined whether the findings of harmful effects came from multiple laboratories; when they did, we cautiously concluded that there was evidence for low-dose effects. Below (*Sections II.C–G*), we present five examples where a significant number of studies were available examining low-dose effects of an EDC on a single particular endpoint.

C. BPA and the prostate: contested effects at low doses?

As discussed briefly above, BPA is one of the best-studied EDCs, with more than 200 published animal studies, many of which focused on low doses (29, 31). The effects of this chemical on wildlife species have also been described in detail (28). BPA is found in a myriad of consumer products, and it leaches from these items under normal conditions of use (4). It has also been regularly detected in air, water, and dust samples. The majority of individuals in industrialized countries have BPA metabolites in their urine, and trends indicate increasing exposures in developing nations like China (87, 244). Although it was long suspected that most human exposures originate from BPA contamination of food and beverages, a study comparing the excretion of BPA metabolites with the length of time spent fasting suggests that there are also likely to be significant exposures from sources other than food and beverages (245). BPA has recently been shown to be used in large quantities in thermal and recycled papers and can enter the skin easily via dermal absorption (246–248). Thus, despite the large amount of information available on BPA sources, our understanding of how these sources contribute to total human exposures remains poor; these studies also point to significant gaps in current knowledge about BPA metabolism in humans (243).

BPA binds to the nuclear and membrane ER, and thus most of the effects of this chemical have been attributed to its estrogenic activity (27). However, there is evidence that it can activate a number of additional pathways, including thyroid hormone receptor, androgen receptor, as well as peroxisome proliferator-activated receptor-γ signaling pathways (249–252). The cutoff for a low dose has been set at several different concentrations depending on which studies and definitions are used (see Table 1). The EPA calculated a reference dose for BPA of 50 μg/kg · d based on a LOAEL of 50 mg/kg · d (38). More recent pharmacokinetic scaling experiments have estimated that exposures to approximately 400 μg/kg · d produce blood concentrations of unconjugated BPA in the range of human blood concentrations (4). Thus, for the two WoE analyses of the BPA literature we conducted, doses of 400 μg/kg · d or lower were considered low dose; pharmacokinetic studies from nonhuman primates support the appropriateness of this dose for approximating human exposure levels (253). Furthermore, because this dose is below the toxicological LOAEL, it is a conservative cutoff for low-dose studies (see Refs. 3 and 38 and Table 1).

One of the most well studied and hotly debated examples of a low-dose effect comes from the BPA literature; regulatory agencies and scientists have addressed several times whether low doses of BPA during fetal and perinatal development affect the rodent prostate (118, 205, 254, 255). In 1997, the first study on BPA and the prostate determined that fetal exposure to low doses (2 and 20 μg/kg · d administered orally to pregnant mice) increased the weight of the adult prostate compared with unexposed male offspring (256). Since that time, several additional studies have verified that prostate weight is affected by fetal exposure to similar low doses (257–259). Studies have also shown that low doses of BPA affect androgen receptor binding activity in the prostate (257), tissue organization, and cytokeratin expression in the gland (260–262) as well as the volume of the prostate and the number and size of dorsolateral prostate ducts (208). Several recent studies have also examined whether low doses of BPA (10 μg/kg · d) influence the incidence of adult-onset prostatic intraepithelial neoplasia (PIN) lesions. Perinatal BPA exposure, whether administered orally or sc to pups, increases the incidence of PIN lesions in response to a mixture of testosterone and estradiol in adulthood (139, 141, 263); this hormonal cocktail was designed to mimic the endocrine changes associated with aging in men that also typically accompany the onset of prostate cancer. In addition to the effects of BPA on PIN lesions, these low doses also produced permanent alterations in the epigenome of exposed males, with prostates displaying completely unmethylated sequences in genes that are hypermethylated in unexposed controls (140, 263). In examining these studies, although the same effects of BPA on the prostate were not observed in all studies, there is an obvious trend demonstrating that low doses of BPA during early development significantly affect several aspects of prostate development.

Since the initial report showing effects of low doses on the prostate, approximately nine studies, including several designed specifically to replicate the original positive study, have shown no effects of low doses on the prostate (264–272); every one of these studies examined the prostate weight, and Ichihara *et al.* (264) also examined the effects of BPA on PIN lesions (without hormonal treatment) and the response of the prostate to a chemical carcinogen. Three of these studies failed to include a positive control of any kind (264, 268, 270); three studies used DES as a positive control but found no effect from exposure to this potent xenoestrogen (265–267) (*i.e.* the positive control failed); another study used 17β-estradiol as a positive control, inappropriately administered orally, and found no effects of this hormone on the prostate (271); and two studies used an estrogenic positive control (ethinyl estradiol) and found effects from its exposure, but only at inappropriately high doses (269, 272). These two studies clearly showed that the positive control dose was too high, because rather than increase the weight of the prostate (as seen after low doses of estrogens in other studies), the positive control decreased the weight of the adult prostate (269, 272).

Although this topic was once considered controversial, using a WoE approach, it is clear that there is strong evidence in support of low-dose effects of BPA on the development of the prostate. The evidence clearly shows that several endpoints, including prostate weight, were affected in similar ways in multiple studies from several different labs at doses below 400 μg/kg · d; most effects were seen at doses below 50 μg/kg · d. Furthermore, PIN lesions were reported after neonatal exposure to 10 μg/kg · d with hormonal treatment in adulthood. No appropriately conducted studies contest this evidence. Therefore, the WoE analysis demonstrates that low doses of BPA significantly alter development of the rodent prostate. The NTP's review of the BPA literature in 2008 indicated that this agency agrees that there is now significant evidence that low-dose BPA adversely affects development of the prostate (273).

D. BPA and the mammary gland: undisputed evidence for low-dose effects

The mammary gland is a conspicuous choice to examine the effects of estrogenic compounds because this organ depends on estrogen for proper development at several critical periods in life (274). The fetal gland expresses ER in the mesenchymal compartment, and just before birth, the epithelium becomes ER positive as well (275). At puberty, estrogen is responsible for ductal elongation and overall development of the gland, allowing the epithelium to fill the stromal compartment in preparation for pregnancy and lactation. Although BPA is an example of a chemical that has been classified as a weak estrogen because it binds with a much lower affinity to ERα compared with 17β-estradiol, even weak estrogens are known to affect the development of the mammary gland during early development (276).

In the first study to examine the effects of BPA on the mammary gland, prepubertal rats were exposed to relatively high doses (100 μg/kg · d or 54 mg/kg · d) for 11 d. After even this short exposure, mammary gland architecture was affected in both dose groups, with increased numbers of epithelial structures and, in particular, structures that suggest advanced development (277). BPA exposure also altered proliferation rates of mammary epithelium and cell cycle kinetics, with an increased number of cells in S-phase and a decreased number of cells in G1. Although relatively high doses of BPA were examined, this initial study indicated that the prepubertal and pubertal gland could be sensitive to BPA.

Many additional studies have examined another critical period, the fetal and neonatal periods, which are sensitive to environmental estrogens (78, 276, 278). Mice exposed prenatally to low doses of BPA via maternal treatment (0.25 μg/kg · d) displayed altered development of both the stromal and epithelial compartments at embryonic d 18, suggesting that exposures affect tissue organization during the period of exposure (176). In addition, similar low doses produced alterations in tissue organization observed in puberty and throughout adulthood, long after exposures ended, and even induced pregnancy-like phenotypes in virgin females (137, 279–282). Female mice exposed to BPA *in utero* displayed heightened responses to estradiol at puberty, with altered morphology of their glands compared with animals exposed to vehicle *in utero* (138). Another study demonstrated that perinatal BPA exposure altered the mammary gland's response to progesterone (283). Remarkably, all of these effects were observed after maternal exposures to low doses (0.025–250 μg/kg), suggesting that the gland is extremely sensitive to xenoestrogen exposures. These studies are in contrast to one that examined the effects of higher doses (0.5 and 10 mg/kg · d) when BPA was administered for 4 d to the dam, which reported advanced development of BPA-exposed glands before puberty but no effects in adulthood (284).

Adult exposure to BPA is only now being examined in the mouse mammary gland model. A recent study examined the effects of BPA on mice with mutations in the *BRCA1* gene. This study reported that 4 wks of exposure to a low dose of BPA altered the tissue organization of the mammary gland in ways that are similar to the effects observed after perinatal exposure (285). This study focused on altered development of the gland during exposure; additional studies are needed to determine whether these effects are permanent or whether normal mammary morphology could be achieved by cessation of BPA exposure.

Another obvious endpoint is the effect of BPA exposure on mammary cancer incidence. Several studies indicate that exposure to BPA *in utero* produces preneoplastic (281, 286, 287) and neoplastic lesions (286) in the gland in the absence of any other treatment. Additionally, other studies show that females exposed to BPA during the perinatal period are more sensitive to mammary carcinogens, decreasing tumor latency and increasing tumor incidence (287–290). These studies are also supported by subsequent studies examining gene and protein expression, which show that low-dose BPA specifically up-regulates expression of genes related to immune function, cell proliferation, cytoskeletal function, and estrogen signaling and down-regulates apoptotic genes (282, 288, 289, 291).

Postnatal BPA exposures also influence mammary cancer incidence; animals exposed lactationally to BPA from postnatal d 2 until weaning displayed decreased tumor latency and increased tumor multiplicity after treatment with DMBA [7,12-dimethylbenz(a)anthracene], a carcinogen (292). This study suggested that BPA exposure led to increased cell proliferation and decreased apoptosis in the gland and shifted the period where the gland is most susceptible to mammary carcinogens, a result that has important implications for human breast cancer. Finally, an additional study examined the effects of adult BPA exposure on mammary cancer; this study demonstrated that low doses of BPA accelerate the appearance of mammary tumors in a tumor-prone mouse strain (293). Interestingly, high doses did not have this effect; thus, this study is also an excellent example of a NMDRC.

Two studies of BPA and the mammary gland seem to contradict this body of literature, but both examined extremely high doses. In the first study, Nikaido *et al.* (294) exposed female mice to 10 mg/kg BPA from postnatal d 15–18. Mammary glands from these animals were examined at 4, 8, and 24 wk of age, and no differences were observed in the exposed animals relative to controls. Although the lack of effects reported in this study could be due to the high dose employed, they could also be related to the relatively short exposure period during the preweaning phase. In the second study, Yin and colleagues (295) examined the effects of BPA during the first few days after birth (0.1 or 10 mg BPA, equivalent to approximately 10 and 1000 mg/kg) on the incidence of mammary tumors after exposure to a mammary carcinogen at puberty. Similar to the study described above, this one also examined the effects of BPA after a relatively short period of exposure (only three injections administered between postnatal d 2 and 6). Although the study showed that BPA affected tissue organization, there was no change in the incidence of tumors in BPA-exposed females. Because both of these studies examined both high doses and relatively short periods of exposure, it is difficult to compare them directly to the studies finding effects of BPA on the mammary gland after longer exposures to lower doses; at the very least, they cannot refute studies suggesting that BPA alters development of this gland.

In summary, the WoE clearly shows that low-dose BPA exposure affects development of the mammary gland, mammary histogenesis, gene and protein expression in the gland, and the development of mammary cancers. In fact, this example of low-dose effects produced remarkably similar effects across more than a dozen studies conducted in several different labs. These results are also consistent with the effects of low-dose BPA exposure on mammary epithelial cells in culture (reviewed in Ref. 30). Although epidemiology studies examining the influence of BPA on breast cancer rates have proven to be inconclusive at best (296), to replicate the animal studies discussed above, epidemiologists must collect information about prenatal and neonatal exposures and relate them to adult breast cancer incidence. These types of studies would take decades to conduct (67) and should take into consideration the effects of other estrogens, because their effects can be additive or even synergistic (143, 144, 297).

Although our analyses of BPA have focused on its effects on the mammary gland and prostate (see *Sections II.C–D*), it is worth noting that several other endpoints have strong data to support the hypothesis that BPA has low-dose effects. In a recent review using similar WoE approaches, Hunt and colleagues (298) focused on those studies that examined the effects of BPA on the oocyte, specifically scrutinizing studies that reported effects, or no effects, on meiotic aneuploidy and other alterations in the intracellular organization and chromosome abnormalities. Similar to what has been observed with the prostate and mammary gland, the effects observed in the oocyte are variable from study to study, but overall consistent, and suggest that BPA exposure produces defects in these cells.

A large number of studies have also focused on the effects of BPA on the brain and behavior, with the most significant effects on sexually dimorphic regions of the brain and behaviors (299–307). Other affected behaviors include social behaviors, learning and anxiety, and maternal-neonate interactions (reviewed in Refs. 29 and 308). The NTP expert panel statement concluded that there were significant trends in these behavioral data and wrote that there was some concern that BPA could have similar effects in humans (273). Low-dose effects have also been reported for BPA in the female reproductive tract (309, 310), immune system (311, 312), maintenance of body weight and metabolism (313, 314), fertility (315–317), and the male reproductive tract (259, 318) (see Refs. 29 and 319 for comprehensive reviews).

E. Another controversial low-dose example: atrazine and amphibian sexual development

Atrazine is an herbicide that is applied in large volumes to crops, and there is concern that agricultural runoff of this chemical can affect nontarget animal species, especially amphibians that live and reproduce in small ponds and streams where significant amounts of atrazine have been regularly measured (320–322). It is the most commonly detected pesticide in ground and drinking water. Atrazine induces aromatase expression in cells and animals after exposure (323); this ultimately causes an increase in the conversion of testosterone to estrogen (324, 325). This effect has been reported in all vertebrate classes examined: fish, amphibians, reptiles, birds, and mammals, including human cell lines (see Ref. 326 for review). Another well-documented effect of atrazine is that it decreases androgen synthesis and activity, again, in every vertebrate class examined (326). In addition, endocrine-disrupting effects of atrazine occur through a number of other mechanisms, including antiestrogenic activity (327), altered prolactin release (328), and increased glucocorticoid release from the adrenal glands (329, 330), among others (327).

Because of atrazine's indirect effect on estrogen levels, one relevant endpoint that has been given attention is the effect of this chemical on gonad differentiation in various amphibian species. The early gonad is bipotential, and in mammals, the expression of genes on the Y-chromosome is needed to masculinize the undifferentiated gonad; when this does not occur, the gonad develops into ovarian tissue. In *Xenopus laevis* frogs (and some other animals like birds), the opposite is true: females are heterogametic (*i.e.* ZW-chromosomes) and males have two of the same chromosomes (*i.e.* ZZ). In *X. laevis*, the W-chromosome is the dominant one, containing a gene, DM-W, which induces aromatase expression (331). Thus, having a W-chromosome is needed to produce estrogen; without the conversion of testosterone to estrogen, the frog develops as a male (332). Changes in sex ratio and gonadal morphology are therefore good indicators that an estrogen, or a chemical that up-regulates aromatase and indirectly increases estrogen levels, is present (76).

Determining a low-dose cutoff for atrazine is not a simple task. Although the safe limit of 3 μg/liter in drinking water was set by the EPA, actual levels in the environment often exceed this concentration (333), and levels in ponds and streams can reach 100 μg/liter (322) or more. In traditional toxicology studies examining several amphibian species, the LOAEL was set at 1.1 mg/liter, and the no observed effect level (NOEL) was 200 μg/liter (334, 335). Thus, using the definitions of low dose established by the NTP (2), we consider any treatment at or below 200 μg/liter to be a low dose.

In 2002, one of the first published studies to connect atrazine exposures to altered gonadal morphology examined *X. laevis* frogs exposed to 0.01–200 μg/liter throughout larval development (336). All doses from 0.1–200 μg/liter produced gonadal malformations including the presence of multiple gonads and hermaphroditism. Several other reports showed similar effects of low doses on gonadal phenotypes including studies that report the production of hermaphrodites and intersex frogs, males with ovotestes, and males with testicular oocytes (337–343). Additional studies showed that low-dose atrazine exposure (0.1–200 μg/liter in the water) during sexual differentiation caused testicular dysgenesis, testicular resorption, and testicular aplasia in male frogs (343, 344), and others indicated effects on sex ratios (339, 342, 345, 346). Importantly, these effects were not all observed at the same atrazine concentration, and the studies were conducted in several different species, with some reporting effects at low doses but no effects at higher doses (341) and others reporting effects in some but not all species (339). Examining these studies as a whole, there is clearly a pattern of effects that are reproducible from study to study, and they collectively support the hypothesis that atrazine disrupts sex hormone concentrations.

To date, five peer-reviewed studies have reported no effects of atrazine on sex ratios, gonadal morphology, the incidence of testicular abnormalities or testicular oocytes, gonad size, or the incidence of intersex phenotypes (347–351). Little can be ascertained from these negative studies, however, because four did not include any positive control, suggesting that the frogs used in those studies may have been incapable of responding to atrazine or any other hormonal treatment (347–350). Additionally, one of those studies reported testicular oocytes in the control frogs, suggesting either that the negative control population was contaminated with atrazine (or another EDC or hormone), or that an inappropriate strain of *X. laevis* was selected for the experiments (347). Only one study remains that did not find any effects of atrazine; this study used an appropriate positive control (17β-estradiol) and found effects of that hormone on sex ratios and the incidence of intersex gonads (351). An EPA expert panel noted, however, that this study used a strain of *X. laevis* that was obtained from a new, unexamined population of frogs from Chile and suggested that this strain may be insensitive to environmental chemicals. Furthermore, the panel called for additional analysis of the data in this study, including the statistical approaches; they suggested that an independent laboratory should evaluate the histopathological results; and they requested that atrazine metabolites be measured (352). The panel also proposed that these experiments should be repeated with an established *X. laevis* strain. Taking together the results of those studies that found effects of atrazine on sexual differentiation, and this one negative study, the WoE for the case of low-dose atrazine on sexual differentiation is clearly in support of adverse effects of this chemical.

Just as epidemiological studies have found links between EDCs and human diseases, ecological field studies have examined whether exposure to atrazine in natural environments affects the development of wild amphibians (343, 353–358). These studies have many of the same constraints as those observed in epidemiology: a paucity of data on early life exposures (including exposure levels of controls), limitations on the total number of EDCs that can be measured in environmental and biological samples, and a lack of causative relationships that can be established between exposures and effects. For these reasons, studies that found relationships between atrazine exposure (or concentrations in environmental samples) and effects on one or more aspect of sexual differentiation (343, 353–355) are considered weak, but significant, evidence for low-dose effects. The presence of several studies suggesting a relationship between low-dose exposure to atrazine in the wild and altered sexual differentiation indicates a plausible causal relationship. Because the ecological and laboratory data show similar effects of atrazine on gonadal development, this strengthens the conclusions of our WoE that low doses of atrazine cause harm to amphibians.

Feminization of males after atrazine exposure is not restricted to amphibians; exposure of zebrafish to low doses increased the ratio of female to male fish and increased expression of aromatase (359). Close to a dozen additional studies also report that environmentally relevant doses of atrazine can up-regulate aromatase, decrease testosterone, and/or increase estrogen levels in a large number of species (reviewed in Ref. 119), suggesting that low-dose effects of atrazine may be more widespread than their effects on the gonads of amphibians. Other studies indicate that low-dose atrazine affects the immune system and stress responses of salamanders (360–362), survivorship patterns of several frog species (363), and thyroid hormone and plasma ion concentrations in salmon (364).

An important factor to consider when examining the effects of atrazine on different animal models is the difficulty in identifying an appropriate low, environmentally relevant dose for all species. Aquatic animals can be housed in water containing levels of atrazine found in wild habitats, yet no toxicokinetic studies are available to determine what administered dose produces the levels of atrazine metabolites, typically in the parts-per-million or ppb range (365, 366), measured in human samples. There are also no blood or urine measurements in exposed rodents to compare with human levels; thus, extrapolations across species are estimates at best.

Keeping this qualification in mind, exposures in the range of 25–100 mg/kg · d during development have been shown to alter mammary gland development (367, 368), estrous cyclicity (369), serum and intratesticular testosterone concentrations (370), timing of puberty in males and prostate weight (371), and immune function (372) in rodents. Lower doses of atrazine metabolites (0.09–8.73 mg/kg · d) altered development of the mammary gland (373), male pubertal timing and prostate development (374). Identifying the range of doses administered to animals that produce the levels of atrazine and its metabolites measured in human blood and urine is an essential research need to pursue low-dose studies in rodents and other mammals.

F. Dioxin and spermatogenesis: low-dose effects from the most potent endocrine disruptor?

Dioxin, or TCDD, is formed as a byproduct of industrial processes as well as during waste incineration. Because TCDD is extremely toxic to some animals, with 1 μg/kg capable of killing 50% of guinea pigs, it has been labeled the most toxic chemical on earth (375). But interestingly, other animals are less sensitive to lethal effects of TCDD, with an LD_{50} of approximately 1000 μg/kg in hamsters, and studies also suggest that humans are not a hypersensitive species for lethality (376). Additionally, there are differences in the half-life of TCDD in different animals; in rodents, the half-life is 2–4 wks, but in humans, the half-life is approximately 10 yrs, and additional factors influence TCDD pharmacokinetics including the exposure level and the amount of body fat present (377–379). In cell cultures, doses as low as 10^{-11} M are toxic, with decreased viability observed even in cells maintained in nonproliferative states (380).

TCDD binds to the aryl hydrocarbon receptor (AhR), and differences in the affinity for the receptor may be responsible for differences in sensitivity between species (381). The K_d (dissociation constant for receptor-ligand binding kinetics) in human samples typically ranges from 3–15 nM, but in samples from rodents, the K_d is less than 1 nM (382). Importantly, there are also nongenomic pathways affected by TCDD that are mediated by AhR that are typically altered within minutes of TCDD exposure and therefore without changes in transcription (383). Yet many studies suggest that important differences exist between species regarding binding affinity of TCDD for AhR and the toxicity of this chemical, but that other adverse effects, including those related to the endocrine-disrupting activities of TCDD, occur at similar doses (or body burdens) across animal species (384, 385). Thus, it is plausible that AhR affinity alone can predict some, but not all, effects of TCDD and related chemicals.

The mechanisms responsible for many of the endocrine-disrupting activities of TCDD are currently not well understood. Knocking out AhR disrupts morphogenesis of several organ systems even in the absence of a ligand like TCDD, suggesting that this receptor plays important roles in early development (386). AhR is translocated to the nucleus after loss of cell-cell contacts and is often localized to the nucleus in embryonic cells, suggesting that it could have ligand-independent effects on development and/or that endogenous ligands could be present during early development (387). When TCDD is present, AhR translocates to the nucleus and dimerizes with ARNT, the aromatic hydrocarbon receptor nuclear translocator (388). Although the (currently unidentified) physiological activators of AhR are likely to induce rapid on/off signaling via AhR, TCDD and related compounds appear to maintain activation of AhR, and the presence of TCDD prevents the normal action of the AhR signaling pathway in the maintenance of homeostasis (389). This induces changes in the expression of genes and promotes the production of toxic metabolites. These effects may be responsible for some of the endocrine-related endpoints affected by TCDD exposure. Additionally, recent studies have shown complex and intricate interactions between the

AhR and ER signaling pathways (390), suggesting that dioxin may also have indirect effects on some ER-mediated endpoints via AhR signaling.

Teratogenic effects of TCDD have been well documented after high-dose (391, 392) and low-dose exposures (393). These studies show that almost every organ and system in the body is affected by this chemical. High doses that did not produce lethality caused severe weight loss, intestinal hemorrhaging, alopecia, chloracne, edemas, and severe liver damage. Sadly, there are now several examples in humans of accidental exposures after the industrial release of TCDD where a number of individuals have been exposed to large doses (389, 394) as well as a few documented intentional poisonings (395). The tolerated daily intake level was set at 1–4 pg/kg · d, although the doses consumed by nursing infants are likely to exceed these levels by a factor of 10 (375). Adult exposures usually result from the consumption of contaminated foods, and because TCDD is lipophilic, it is concentrated in the fat component of breast milk and therefore passed in large quantities from a nursing mother to her infant.

Using classical toxicology methods, the effects of single TCDD doses were examined in adult male rats, specifically focusing on the effects of this chemical on the number of spermatids per testis and the integrity of the testicular germinal epithelium (396). In one of the earliest studies, Chahoud and colleagues (397) determined a LOAEL of 3 μg/kg · d and set the NOAEL at 1 μg/kg · d for effects on the testes. Because there are significant differences in the toxicity of TCDD between animal models, and different endpoints have different identified NOAELs, we have selected the 1 μg/kg · d identified by Chahoud *et al.* as the cutoff for low-dose studies of this compound. This cutoff is based on the NTP's definition of low dose as occurring at doses lower than those tested in traditional toxicology assessments (2). However, it is important to acknowledge that body burdens that mimic those observed in human populations are likely the best indicators of low doses for TCDD (384), and thus we recommend that future studies determine body burdens after administration of TCDD for the specific strain, origin, and species of animal being tested to ensure that truly low doses, relevant to human populations, are being tested.

Several recent epidemiological studies have indicated that relatively high exposures to TCDD during early life (due to industrial release of high amounts of the chemical) can permanently affect semen quality and sperm count in men (398). Yet epidemiology studies also clearly show that the timing of TCDD exposure can vastly influence the effect of this chemical on spermatogenesis; exposures during perinatal life significantly reduced sperm parameters, but exposures during puberty increased sperm counts; exposures in adulthood had no effect on sperm parameters (399). Thus, it is also important for animal studies to focus on exposures during critical periods for development of the male reproductive tract and spermatogenesis in particular.

We are aware of 18 studies that have examined the effects of low doses ($\leq$1 μg/kg · d) of TCDD during perinatal development on male fertility endpoints in adulthood. The endpoints assessed vary, including epididymal sperm counts, ejaculated sperm number, daily sperm production, sperm transit rate, and percent abnormal sperm, and the sensitivity of these endpoints appears to impact the ability to detect low-dose effects in different studies (400, 401) (Table 5). In total, 16 rodent studies examined the effect of low-dose TCDD on epididymal sperm count; 12 showed significant effects on this endpoint (402–413), whereas the other four did not (414–417). Of the five studies that examined ejaculated sperm counts, four studies (404, 405, 408), including one examining rhesus monkeys (418), showed effects of low-dose TCDD, *i.e.* a significant decrease in sperm counts; one study found no effect (417). Daily sperm production was a less-sensitive endpoint, with four studies showing significant decreases after prenatal exposure to low doses (402, 403, 407, 409) and four studies showing no effects (406, 412, 413, 416); sperm transit rate was examined in only two studies, although both showed significant decreases in sperm tranfer rates (403, 410); and finally, three studies determined that low-dose TCDD produced abnormalities in sperm appearance or motility (414, 415, 419), but one study was not able to replicate these findings (417).

When examining the TCDD literature as a whole, the WoE strongly suggests that prenatal exposure to low doses of TCDD affects sperm-related endpoints in adulthood (Table 5). In all, only two studies were unable to detect any effect of TCDD on the sperm endpoints assessed, although both studies found effects of TCDD on other endpoints including the weight of the adult prostate (416) and the timing of puberty (417). No study on TCDD used a positive control, likely due to a paucity of information on the mechanisms of dioxin action, but this raises obvious questions about the ability of these experimental systems to detect effects on spermatogenesis. Finally, some of the inability to detect effects of TCDD could be due to the use of insensitive strains, because 1000-fold differences in sensitivity have been reported for different rodent strains (420).

Even though we have focused the majority of our attention on the effects of low-dose TCDD exposure on spermatogenesis, it should be noted that low doses of this chemical affect a multitude of endpoints in animals, altering immune function (421, 422), indicators of oxidative

TABLE 5. Summary of low-dose animal studies examining the effects of TCDD on spermatogenesis endpoints

Study	Administered dose (time of administration)	Animal	Epididymal sperm count	Ejaculated sperm no.	Daily sperm production	Sperm transit rate	% abnormal sperm
Mably *et al.* (409)	0.064–1 μg/kg (gestational d 15)	Rat	Decreased	NA	Decreased	NA	NA
Bjerke and Peterson (402)	1 μg/kg (gestational d 15)	Rat	Decreased	NA	Decreased	NA	NA
Gray *et al.* (404)	1 μg/kg (gestational d 8)	Rat	Not significant	Decreased	NA	NA	NA
	1 μg/kg (gestational d 15)	Rat	Decreased	Decreased	NA	NA	NA
	1 μg/kg (gestational d 11)	Hamster	Decreased	Decreased	NA	NA	NA
Sommer *et al.* (408)	1 μg/kg (gestational d 15)	Rat	Decreased	Decreased	Decreased	Not significant	Not significant
Wilker *et al.* (410)	0.5, 1 or 2 μg/kg (gestational d 15)	Rat	Decreased	NA	Unaffected	Increased	NA
Gray *et al.* (405)	0.05–1 μg/kg (gestational d 15)	Rat	Decreased	Decreased	Decreased	NA	NA
Faqi *et al.* (403)	0.025–0.3 μg/kg (before mating, then 0.005–0.06 μg/kg weekly [to dams])	Rat	Decreased	NA	Decreased	Increased	Increased
Loeffler and Peterson (412)	0.25 μg/kg (gestational d 15)	Rat	Decreased	NA	Unaffected	NA	NA
Ohsako *et al.* (416)	0.0125–0.8 μg/kg (gestational d 15)	Rat	Not significant	NA	Unaffected	NA	NA
Ohsako *et al.* (406)	1 μg/kg (gestational d 15)	Rat	Decreased	NA	Unaffected	NA	NA
	1 μg/kg/gestational d 18	Rat	Unaffected	NA	Unaffected	NA	NA
	1 μg/kg/postnatal d 2 (to pups)	Rat	Unaffected	NA	Unaffected	NA	NA
Simanainen *et al.* (407)	0.03–1 μg/kg (gestational d 15)	Rat	Decreased	NA	Decreased	NA	NA
Yonemoto *et al.* (417)	0.0125–0.8 μg/kg (gestational d 15)	Rat	Unaffected	Unaffected	NA	NA	Unaffected
Yamano *et al.* (714)	0.3 or 1 μg/kg (postnatal d 1 and then every week [to dams])	Rat	Not significant	NA	NA	NA	NA
Ikeda *et al.* (715)	0.4 μg/kg (before mating, then 0.08 μg/kg weekly [to dams])	Rat	Unaffected	NA	NA	NA	NA
Bell *et al.* (414)	0.05–1 μg/kg (gestational d 15)	Rat	Increased (at certain ages)	NA	NA	NA	Increased
Bell *et al.* (415)	0.0024–0.046 μg/kg (d 12 weeks before pregnancy through parturition)	Rat	Unaffected	NA	NA	NA	Increased
Arima *et al.* (418)	0.03 or 0.3 μg/kg (gestational d 20, then 5% of dose monthly [to dams])	Rhesus monkey	Decreased	Not significant	NA	NA	Not significant
Yamano *et al.* (419)	0.3 or 1 μg/kg (weekly to dams then pups [all postnatal])	Rat	NA	NA	NA	NA	Increased
Jin *et al.* (411)	1 μg/kg · d (postnatal days 1–4 [to dams])	Mouse	Decreased	NA	NA	NA	NA
Rebourcet *et al.* (413)	0.01–0.2 μg/kg (gestational d 15)	Rat	Decreased (at some ages)	NA	Not significant	NA	NA

Not significant indicates trend for effect but did not reach statistical significance. Unaffected means assessed, but no differences were observed relative to controls. Here, low doses were considered any at or below 1 μg/kg · d (see text for discussion of how this cutoff was established for rodent studies). NA, Not assessed.

stress (423–425), bone and tooth development (426, 427), female reproduction and timing of puberty (428–430), mammary gland development and suceptibility to cancers (431), behaviors (432, 433), and others. In several cases, lower doses were more effective at altering these endpoints than higher ones (423, 424, 426, 433). Epidemiology studies of nonoccupationally exposed individuals also indicate that serum TCDD levels may be linked to diseases in humans as well (434). Mean serum TCDD levels have decreased by a factor of 7 over a 25-yr period (1972–97) in several industrial nations (435), but results from both animal and epidemiological studies suggest that even the low levels detected now could have adverse effects on health-related endpoints.

G. Perchlorate and thyroid: low-dose effects in humans?

A significant challenge with observing low-dose effects of EDCs in the human population is that human chemical exposures are multivariate along the vectors of time, space, and sensitivities. In addition, chemicals can exert effects on several systems simultaneously. Therefore, associations in human studies between exposures and disease are difficult to reconcile with experimental studies in animal model systems. For this reason, the literature describing the potential impacts of perchlorate contamination on the human population is potentially clarifying because to the best of our knowledge, perchlorate exerts only a single effect, and the pharmacology of perchlorate exposures has been studied in human volunteers (436). This literature offers a unique perspective into the issue of low-dose effects, perhaps providing important hypotheses to explain mechanistically why high-dose, short-term experiments can fail to predict the outcome of low-dose, lifetime exposures.

In the 2001–2002 NHANES dataset, perchlorate was detected in the urine of each of the 2820 samples tested (437). This widespread exposure means that the human population is being continuously exposed because perchlorate has a half-life in the human body of about 8 h (438). Human exposures to perchlorate are likely attributed to both contaminated drinking water and food (439); in fact, a recent analysis concludes that the majority of human exposure to perchlorate comes from food (440).

The predominant theory proposed to explain the source of perchlorate contamination in the United States is that it has been employed for many decades as the principal oxidant in explosives and solid rocket fuels (441). Perchlorate is chemically stable when wet and persists for long periods in geological systems and in ground water. Because of disposal practices during the 1960s through 1990s, perchlorate became a common contaminant of ground water in the United States (441, 442). Perchlorate is also formed under certain kinds of natural conditions (443), although the relative contributions to human exposure of these different sources is not completely understood. As a result of perchlorate contamination of natural waters, the food supply has become contaminated through irrigation in part because both aquatic and terrestrial plants can concentrate perchlorate more than 100-fold over water levels (444).

This exposure profile in the human population is important because high doses of perchlorate are known to reduce functioning of the thyroid gland, and poor thyroid function is an important cause of developmental deficits and adult disease (445). The primary question is: at what dose does perchlorate inhibit thyroid function sufficiently to cause disease? The current literature, reviewed below, supports the view that background exposure may affect thyroid function in adult women. These exposure levels, however, are considerably lower than predicted by early toxicology experiments in humans.

Perchlorate reduces thyroid function by inhibiting iodide uptake by the sodium/iodide symporter (NIS) (446), which is the only known effect of perchlorate on human physiology (438). NIS is responsible for transporting iodide into the thyroid gland, which is required for the production of thyroid hormone (447). However, NIS is also expressed in the gut (448, 449), in lactating breast (448, 450, 451), and in placenta (452), presumably all as a delivery mechanism for iodide to the developing and adult thyroid gland. Because the NIS transports perchlorate (450), the pathway by which humans take up and concentrate perchlorate is the same as the pathway by which humans take up and concentrate iodide. Interestingly, NIS expression in the human fetal thyroid gland is the rate-limiting step in production of thyroid hormone (453). Moreover, NIS transport of perchlorate explains why high levels of perchlorate are found in human amniotic fluid (454, 455) and breast milk (456–459).

This effect of perchlorate on thyroid function is important because thyroid hormone is essential for normal brain development, body growth as well as for adult physiology (445, 460). Moreover, it has become clear that even small deficits in circulating thyroid hormone in pregnant women (461, 462) or neonates (463) have permanent adverse outcomes. In fact, recent work indicates that very subtle thyroid hormone insufficiency in pregnant women is associated with cognitive deficits in their children (461). Because of the importance of thyroid hormone in development and adult physiology, and because perchlorate is a potent inhibitor of iodide uptake and thyroid hormone synthesis, identifying the dose at which these events occur is critical.

Perchlorate was used medically to reduce circulating levels of thyroid hormone in patients with an overactive thyroid gland in the 1950s and 1960s (reviewed in Ref. 446); therefore, it was reasonable to examine the dose-response characteristics of perchlorate on the human thyroid gland. Because perchlorate inhibits iodide uptake, several studies were performed to evaluate the effect of perchlorate exposure on iodide uptake inhibition in human volunteers (438, 464–466). In one study, 0.5 or 3 mg/d (approximately 0.007 and 0.04 mg/kg · d) perchlorate was administered to healthy volunteers (n = 9 females and 5 males, age 25–65 yr), and no effects were observed (466). Of course, it is important to note that the 2 wk of administration tested in this study is not sufficient to see any effect on serum concentrations of T_4 or TSH; the healthy thyroid can store several months' worth of thyroid hormone in the gland (467). Another small study also found no effects of administering 3 mg/d (approximately 0.04 mg/kg · d) on any thyroid endpoint assessed (n = 8 adult males) (464).

In contrast, two studies examining adult volunteers administered perchlorate found effects of this chemical on at least one endpoint. The first found that radioactive iodide uptake was affected by 2 wk of exposure to 10 mg/d (0.13 mg/kg · d), but other measures of thyroid function were not altered (n = 10 males) (465). The second examined adults (n = 37) given doses ranging from 0.007–0.5 mg/kg · d; all but the lowest dose altered radioactive iodide uptake, and only the highest dose altered TSH levels (438). These studies were interpreted to suggest that adults would have to consume 2 liters of drinking water daily that was contaminated with at least 200 ppb (200 μg/liter) perchlorate to reach a level in which iodide uptake would begin to be inhibited. Yet, these administered doses are high and relatively acute, so the derivation of a safe dose from these studies, applied to vulnerable populations such as those with low iodide intake, has been strongly disputed (471).

Studies of occupational exposures have also been used to examine the effects of exposure to relatively high levels of perchlorate. In the first such study, more than 130 employees were separated into eight groups based on exposure estimates from airborne perchlorate in the workplace (472). The authors found that individuals with longer daily exposures to perchlorate, due to longer work shifts, had significant decreases in TSH levels compared with individuals with shorter exposures. But this study was hampered because actual exposure levels were not measured via urine or blood samples. A second study examined 37 employees exposed to perchlorate and 21 control employees from an azide factory; actual exposure measures were not conducted, but estimates were calculated based on exposures to perchlorate dust and air samples (473). This study found no effects of perchlorate exposures on any thyroid endpoint, although the sample size examined was small. In the final occupational exposure study, serum perchlorate levels were measured and compared with several measures of thyroid function in workers (n = 29) who had spent several years as employees in a perchlorate production plant (474). In this study, the most complete because of the biomonitoring aspect of the exposure measures, higher perchlorate levels were associated with lower radioactive iodide uptake, higher urinary iodide excretion, and higher thyroid hormone concentrations.

Although iodide uptake was often inhibited in these studies, serum thyroid hormones were typically not altered, perhaps because of sufficient stored hormone. Based on these observations, the National Academy Committee to Assess the Health Implications of Perchlorate Ingestion (467) estimated that perchlorate would have to inhibit thyroid iodide uptake by about 75% for several months to cause a reduction in serum thyroid hormones. Moreover, the drinking water concentration of perchlorate required for this kind of inhibition was estimated to be over 1,000 ppb (438). Therefore, the National Academy of Sciences committee recommended a reference dose of 0.0007 mg/kg · d (467), based on the dose at which perchlorate could inhibit iodide uptake, and the EPA used this value to set a provisional drinking water standard of 15 ppb.

Considering these data and general knowledge about the thyroid system, it was unexpected that Blount *et al.* (475) would identify a positive association between urinary iodide and serum TSH in adult women in the NHANES 2001–2002 dataset. Yet several features of this dataset were consistent with a causal action of perchlorate on thyroid function. First, in the general population of adult women, urinary perchlorate was positively associated with serum TSH. In the population of adult women who also had low urinary iodide, however, urinary perchlorate was more strongly associated with serum TSH and was negatively associated with serum T_4. The strength of this association was such that the authors calculated that women at the 50th percentile of perchlorate exposure experienced a 1 μg/dl T_4 reduction (reference range = 5–12 μg/dl). Should this magnitude of reduction in serum T_4 occur in a neonate, measurable cognitive deficits would also be present (476). Finally, Steinmaus *et al.* (477), using the same NHANES dataset, showed that women with low urinary iodide who smoke had an even stronger association between urinary perchlorate and measures of thyroid function. Tobacco smoke delivers thiocyanates, which also inhibit NIS-mediated iodide uptake (446).

The NHANES dataset suggests that perchlorate exposures of 0.2–0.4 μg/kg · d (440) are associated with depressed thyroid function, even when urinary iodide is not reduced. This is a considerably lower dose than the 7 μg/kg · d dose required to suppress iodide uptake in the Greer *et al.* (438) study or the 500 μg/kg · d the NAS estimated would be required for several months to actually cause a decline in serum T_4. Therefore, it is reasonable to question whether these associations represent a causative relationship between perchlorate and thyroid function.

A number of epidemiological studies have been published to test for a relationship between perchlorate exposure and thyroid function. Early work used neonatal screening data for T_4 as a measure of thyroid function, and the city of birth (Las Vegas, NV, compared with Reno, NV) as a proxy measure of exposure (478, 479). The reported findings were negative, but we now know that all Americans are exposed to perchlorate, so there was considerable misclassification of exposure, and no relationship should have been observed. Several additional studies using similar flawed designs also found no relationship between proxy measures of perchlorate exposures and clinical outcomes (480–484).

A recent study of the neonatal screening data from 1998 in California identified a strong association between neonatal TSH and whether or not the mother resided in a contaminated area (485). This study included over 497,000 TSH measurements and 800 perchlorate measurements. In addition, they used as a cutoff a variety of TSH levels (as opposed to the 99.9th percentile used for the diagnosis of congenital hypothyroidism), indicating that perchlorate exposure is not associated with congenital hypothyroidism. Two additional studies have shown similar relationships between perchlorate and TSH levels, particularly in families with a history of thyroid disease (486, 487).

Several studies in pregnant women have failed to identify a relationship between perchlorate exposure and measures of thyroid function (488–490). Although these are important studies that need to be carefully scrutinized, they do not replicate or refute the NHANES dataset. It thus remains important to conduct additional studies exploring the relationship between background exposure to perchlorate and thyroid function in adults, pregnant women, neonates, and infants. This effort will be challenging because of the different characteristics of thyroid function and hormone action at different life stages (460). In addition, it will be important to obtain individual measurements of exposures to perchlorate and other NIS inhibitors (thiocyanate and nitrate), and iodide itself as well as individual measures of thyroid function (free and total T_4 and TSH).

If background levels of perchlorate affect thyroid function in any segment of the population, it will be challenging to explain how the high-dose, short-term experiments of Greer *et al.* (438) completely underestimated the sensitivity of the human thyroid gland to perchlorate exposure. One possibility is that physiological systems respond to short durations of robust stress with compensatory mechanisms that reset during periods of long-term stress.

When these data are examined together, several important issues are raised. First, this example illustrates the difficulties inherent in studying human populations; epidemiology yields associations, not cause-effect relationships, in many cases using surrogate markers for perchlorate, and is not able to distinguish short- *vs.* long-term exposure duration. Second, our WoE analysis suggests that there is weak evidence for low-dose effects of perchlorate; further research is needed. The relationship between low-dose perchlorate exposures and thyroid endpoints would be strengthened by the addition of studies that measure biological concentrations of perchlorate and compare them with thyroid endpoints in neonates and other vulnerable populations. Third, the published studies that reported low-dose effects of perchlorate typically examined very specific populations, with several focusing on women with low iodine intake. This observation suggests that some groups may be more vulnerable to low doses of perchlorate than others (491).

H. Low-dose summary

These examples, and the examples of low-dose effects in less well-studied chemicals (Table 3), provide evidence that low-dose effects are common in EDC research and may be the default expectation for all chemicals with endocrine activity. Many known EDCs have not been examined for low-dose effects, but we predict that these chemicals will have effects at low doses if studied appropriately. Although studies unable to detect effects at low doses have received attention, including some studies designed to replicate others that reported low-dose effects, the majority of these studies contain at least one major design flaw. Thus, a WoE approach clearly indicates that low-dose effects are present across a wide span of chemical classes and activities.

III. Nonmonotonicity in EDC Studies

A concept related to low dose is that of nonmonotonicity. As noted in *Section I.B*, in a monotonic response, the observed effects may be linear or nonlinear, but the slope does not change sign (Fig. 3, A and B). In contrast, a dose-response curve is nonmonotonic when the slope of the curve changes sign somewhere within the range of doses examined (Fig. 3C). NMDRCs are often U-shaped (with maximal responses of the measured endpoint observed at low and high doses) or inverted U-shaped (with maximal responses observed at intermediate doses) (Fig. 3C, *top panels*). Some cases are more complicated, with multiple points along the curve at which the slope of the curve reverses sign (Fig. 3C, *bottom left*). Nonmonotonicity is not synomymous with low dose, because there are low-dose effects that follow monotonic dose-response curves. Thus, it is not required that a study include doses that span from the true low-dose range to the high toxicological range to detect nonmonotonicity. The consequence of NMDRCs for toxicity testing is that a safe dose determined from high doses does not guarantee safety at lower, untested doses that may be closer to current human exposures.

Examples of NMDRCs from the cell culture, animal, and epidemiological literature will be discussed in detail in *Section III.C*. Importantly, our review of the literature finds that NMDRCs are common in the endocrine and EDC literature. In fact, it is plausible that, considering the mechanisms discussed below, NMDRCs are not the exception but should be expected and perhaps even common.

A. Why is nonmonotonicity important?

NMDRCs in toxicology and in the regulatory process for EDCs are considered controversial. In addition to discussions of whether NMDRCs exist, there is also discussion of whether those that do exist have relevance to

Figure 3.

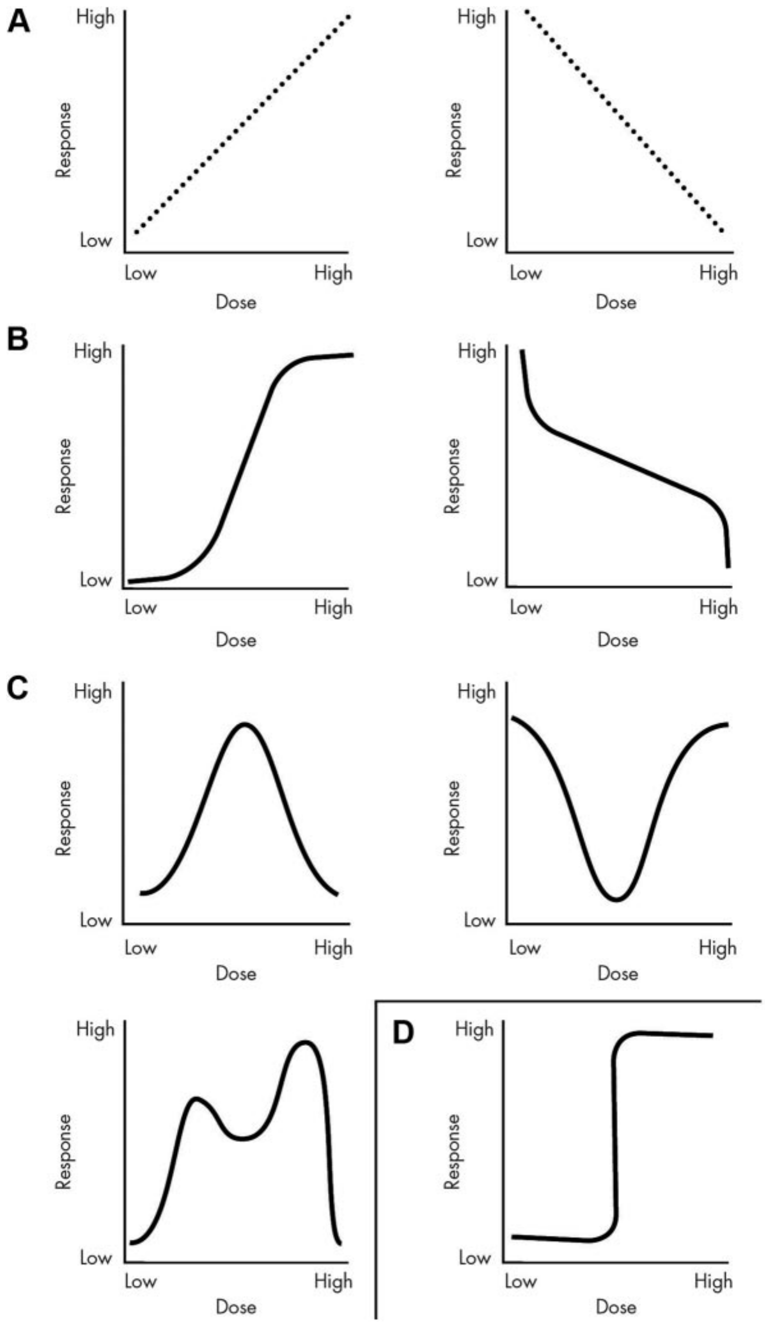

Figure 3. Examples of dose-response curves. A, Linear responses, whether there are positive or inverse associations between dose and effect, allow for extrapolations from one dose to another. Therefore, knowing the effects of a high dose permits accurate predictions of the effects at low doses. B, Examples of monotonic, nonlinear responses. In these examples, the slope of the curve never changes sign, but it does change in value. Thus, knowing what happens at very high or very low doses is not helpful to predict the effect of exposures at moderate doses. These types of responses often have a linear component within them, and predictions can be made within the linear range, as with other linear responses. C, Displayed are three different types of NMDRCs including an inverted U-shaped curve, a U-shaped curve, and a multiphasic curve. All of these are considered NMDRCs because the slope of the curve changes sign one or more times. It is clear from these curves that knowing the effect of a dose, or multiple doses, does not allow for assumptions to be made about the effects of other doses. D, A binary response is shown, where one range of doses has no effect, and then a threshold is met, and all higher doses have the same effect.

toxicological determination of putative safe exposures. In the standard practice of regulatory toxicology, the calculated safe dose, also called a reference dose, is rarely tested. In a system that is responding nonmonotonically, it is not appropriate to use a high-dose test to predict low-dose effects. Unfortunately, all regulatory testing for the effects of chemical exposures assume that this is possible. All current exposure standards employed by government agencies around the world, including the FDA and EPA, have been developed using an assumption of monotonicity (492, 493). The low-dose range, which presumably is what the general public normally experiences, is rarely, if ever, tested directly.

The standard procedure for regulatory testing typically involves a series of tests to establish the lowest dose at which an effect is observable (the LOAEL), then a dose beneath that at which no effect is observable (the NOAEL). Then a series of calculations are used to acknowledge uncertainty in the data, species differences, age differences, *etc.*, and those calculations, beginning with the LOAEL or the NOAEL, produce a reference dose that is presumed to be a safe exposure for humans (Fig. 4). Typically, the reference dose is 3- to 1000-fold lower than the NOAEL. That reference dose then becomes the allowable exposure and is deemed safe, even when it is never examined directly. For chemicals with monotonic linear dose-response curves (Fig. 3A), this may be appropriate. But for any chemicals that display nonmonotonic patterns, it is likely to lead to false negatives, *i.e.* concluding that exposure to the reference dose is safe when in fact it is not.

As described above, there are other nonlinear dose-response curves that are monotonic (Fig. 3B). These curves may also present problems for extrapolating from high doses to low doses because there is no linear relationship that can be used to predict the effects of low doses. Equally troubling for regulatory purposes are responses that have a binary response rather than a classical dose-response curve (Fig. 3D). In these types of responses, one range of doses has no effect on an endpoint, and then a threshold is met, and all higher doses have the same effect. An example is seen in the atrazine literature, where doses below 1 ppb had no effect on the size of the male larynx but doses at or above 1 ppb produced a significant decrease in size of approximately 10–15% (336). Even doses of 200 ppb, the toxicological NOEL, produce the same effect. Thus, this all-or-none effect is observed because atrazine does not shrink the larynx; instead, it removes the stimulatory agent (*i.e.* androgens). In the absence of some threshold dose of androgen, the larynx simply remains at the unstimulated (female) size. The EPA's assessment of this study and others was that the lack of a dose-dependent response negates the importance of this effect (352). The lack of a dose response for a threshold effect like larynx size does not mean that the effects are not dose dependent; thus, understanding these types of effects and their implications for risk assessments is essential for determining the safe levels of chemicals.

It is important to mention here that the appropriateness of determining NOAEL concentrations, and therefore calculating reference doses, from exposures to endogenous hormones or EDCs has been challenged by several studies (Fig. 4A) (494–496). These studies show that hormonally active agents may still induce significant biological effects even at extremely low concentrations and that presently available analytical methods or technologies might be unable to detect relatively small magnitudes of effects. Previous discussions of this topic have shown that as the dose gets lower (and approaches zero) and the effect size decreases, the number of animals needed to achieve the power to detect a significant effect would have to increase substantially (497). Even more importantly, the assumption of a threshold does not take into account situations where an endogenous hormone is already above the dose that causes detectable effects and that an exogenous chemical (whether an agonist or antagonist) will modulate the effect of the endogenous hormone at any dose above zero (Fig. 4B). There can thus be no threshold or safe dose for an exogenous chemical in this situation. Forced identification of NOAEL or threshold doses based on the assumption that dose-response curves are always monotonic without considering the background activity of endogenous hormones and the limitations of analytical techniques supports the misconception that hormonally active agents do not have any significant biological effects at low doses. Thus, the concept that a toxic agent has a safe dose that can be readily estimated from the NOAEL derived from testing high, acutely toxic doses is overly simplistic and contradicted by data when applied to EDC (5, 497, 498).

B. Mechanisms for NMDRCs

Previously, the lack of mechanisms to explain the appearance of NMDRCs was used as a rationale for ignoring these phenomena (492, 493). This is no longer acceptable because there are several mechanisms that have been identified and studied that demonstrate how hormones and EDCs produce nonmonotonic responses in cells, tissues, and animals. These mechanisms include cytotoxicity, cell- and tissue-specific receptors and cofactors, receptor selectivity, receptor down-regulation and desensitization, receptor competition, and endocrine negative FEEDBACK loops. These mechanisms are well understood, and by providing detailed biological insights at the molecular level into the etiology of NMDRCs, they strongly negate the presumption that has been central to regulatory toxicology that dose-response curves are by default monotonic.

1.Cytotoxicity

The simplest mechanism for NMDRCs derives from the observation that hormones can be acutely toxic at high doses yet alter biological endpoints at low, physiologically relevant doses. Experiments working at concentrations that are cytotoxic are incapable of detecting responses that are mediated by ligand-binding interactions. For example, the MCF7 breast cancer cell line proliferates in response to estradiol in the low-dose range (10^{-12} to 10^{-11} M) and in the pharmacological and toxicological range (10^{-11} to 10^{-6} M), but toxic responses are observed at higher doses (38). Thus, when total cell number is graphed, it displays an inverted U-shaped response to estrogen. But cells that do not contain ER, and therefore cannot be affected by the hormonal action of estradiol, also display cytotoxic responses when treated with high doses of hormone. These results clearly indicate that the effects of estradiol at high doses are toxic via non-ER-mediated mechanisms.

2. Cell- and tissue-specific receptors and cofactors

Some NMDRCs are generated by the combination of two or more monotonic responses that overlap, affecting a common endpoint in opposite ways via different pathways. For example, *in vitro* cultured prostate cell lines demonstrate a nonmonotonic response to increasing doses of androgen where low doses increase cell number and higher doses decrease cell number, thus producing an inverted U-shaped curve (499, 500). Although the parental cell expressed an inverted U-shaped dose-response curve, after a long period of inhibition, the effects on cell number could be segregated by selecting two populations of cells: one that proliferated in the absence of androgens and other cells that proliferated in the presence of high androgen levels (501). Thus, the observed inverted U-shaped response is due to actions via two independent pathways that can be separated from each other in an experimental setting (502). Similarly, estrogens have been shown to induce cell proliferation and inhibit apoptosis in several cell populations, but inhibit proliferation and induce apopto-

Figure 4.

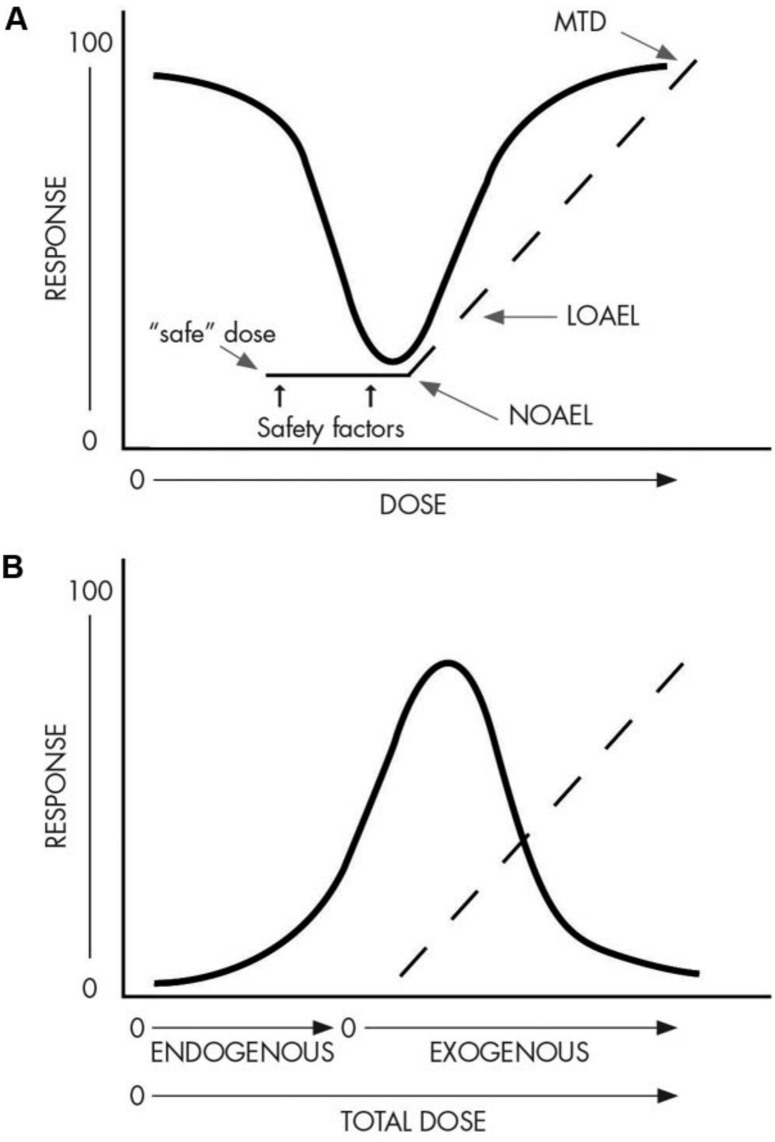

Figure 4. NOAEL, LOAEL, and calculation of a safe reference dose. A, In traditional toxicology testing, high doses are tested to obtain the maximum tolerated dose (MTD), the LOAEL, and the NOAEL. Several safety factors are then applied to derive the reference dose, *i.e.* the dose at which exposures are presumed safe. This reference dose is rarely tested directly. Yet when chemicals or hormones produce NMDRCs, adverse effects may be observed at or below the reference dose. Here, the doses that would be tested are shown by a *dotted line*, and the calculated safe dose is indicated by a *thick solid line*. The actual response, an inverted U-shaped NMDRC, is shown by a *thin solid line*. B, Experimental data indicate that EDCs and hormones do not have NOAELs or threshold doses, and therefore no dose can ever be considered safe. This is because an exogenous hormone (or EDC) could have a linear response in the tested range (*dotted line*), but because endogenous hormones are present (*thin solid line*), the effects of the exogenous hormone are always observed in the context of a hormone-containing system.

sis in others (503, 504), with the combined effect being an inverted U-shaped curve for cell number (505).

Why does one single cell type have different responses to different doses of the same hormone? The case of the prostate cell line described above is reminiscent of the results described from the transcriptome of MCF7 cells, whereby a discrete global response like cell proliferation manifests at significantly lower estrogen doses than the induction of a single marker gene (135). That a response like cell proliferation requires a significantly lower dose of hormone than the dose needed to induce a given target gene is counterintuitive but factual; it may be interpreted as consistent with the notion that metazoan cells, like cells in unicellular organisms, are intrinsically poised to divide (503, 506, 507) and that quiescence is an induced state (508, 509). The biochemical details underlying these different responses are largely unknown; however, recent studies showed that steroid receptors control only a portion of their target genes directly via promoter binding. The majority of the changes are indirect, through chromatin rearrangements (510, 511).

Why do different cell types (*in vitro* and *in vivo*) have different responses to the same hormone? One answer is that they may express different receptors, and these receptors have different responses to the same hormone. For example, some tissues express only one of the two major ER (ERα and ERβ), and actions via these receptors are important not just for responsiveness to hormone but also for cellular differentiation and cross talk between tissue compartments (512). Yet other tissues express both ERα and ERβ, and the effects of signaling via these two receptors often oppose each other; *i.e.* estrogen action via ERα induces proliferation in the uterus, but ERβ induces apoptosis (154). Complicating the situation further, different responses to a hormone can also be obtained due to the presence of different cofactors in different cell and tissue types (513, 514); these coregulators influence which genes are transcriptionally activated or repressed in response to the presence of hormone. They can also influence ligand selectivity of the receptor and DNA-binding capacity, having tremendous impact on the ability of a hormone to have effects in different cell types (105, 515, 516).

Although much of these activities occur on a biochemical level, *i.e.* at the receptor, there is also evidence that nonmonotonicity can originate at the level of tissue organization. The mammary gland has been used as a model to study inter- and intracompartmental effects of hormone treatment: within the ductal epithelium, estrogen has distinct effects during puberty, both inducing proliferation, which causes growth of the ductal tree, and inducing apoptosis, which is required for lumen formation (517, 518); in cell culture, the presence of stromal cells can also enhance the effects of estrogen on epithelial cells (519, 520), suggesting that stromal-epithelial compartmental interactions can mediate the effects of estrogen.

3. Receptor selectivity

NMDRCs can occur because of differences in receptor affinity, and thus the selectivity of the response, at low *vs.* high doses. For example, at low doses, BPA almost exclusively binds to the ER (including mER), but at high doses it can also bind weakly to other hormone receptors, like androgen receptor and thyroid hormone receptor (249, 521). This type of receptor nonselectivity is quite common for EDCs, and it has been proposed that binding to different receptors may be an explanation for the diverse patterns of disease observed after EDC exposures (522). In fact, several of the chemicals shown to have low-dose effects are known to act via multiple receptors and pathways (Table 3). Thus, the effects seen at high doses can be due to action via the binding of multiple receptors, compared with the effects of low doses, which may be caused by action via only a single receptor or receptor family.

4. Receptor down-regulation and desensitization

When hormones bind to nuclear receptors, the ultimate outcome is a change in the transcription of target genes. When the receptor is bound by ligand, an increase in response is observed; as discussed previously in this review, the relationship between hormone concentration and the number of bound receptors, as well as the relationship between the number of bound receptors and the biological effect, is nonlinear (38). After the nuclear receptor is bound by hormone and transcription of target genes has occurred (either due to binding of the receptor at a DNA response element or the relief of a repressive event on the DNA), the reaction eventually must cease; *i.e.* the bound receptor must eventually be inactivated in some way. Thus, nuclear hormone receptors are ubiquitinated and degraded, usually via the proteasome (523). Importantly, the role of the hormone in receptor degradation differs depending on the hormone; binding of estrogen, progesterone, and glucocorticoid mediates the degradation of their receptors (524–526), whereas the presence of hormone may actually stabilize some receptors and prevent degradation (527), and other receptors are degraded without ligand (528). As hormone levels rise, the number of receptors being inactivated and degraded also rises, and eventually the number of receptors being produced cannot maintain the pace of this degradation pathway (523). Furthermore, the internalization and degradation of receptors can also influence receptor production, leading to an even stronger down-regulation of receptor (529). In the animal, the role of receptor down-regulation is actually quite complex, because signaling from one hormone receptor can influence protein levels of another receptor; *i.e.* ER signaling can promote degradation of the glucocorticoid receptor by increasing the expression of enzymes in the proteasome pathway that degrade it (530).

There is also the issue of receptor desensitization, a process whereby a decrease in response to a hormone is not due to a decrease in the number of available receptors but instead due to the biochemical inactivation of a receptor (531). Desensitization typically occurs when repeated or continuous exposure to ligand occurs. Normally seen with membrane-bound G protein-coupled receptors, the activation of a receptor due to ligand binding is quickly followed by the uncoupling of the activated receptor from its G proteins due to phosphorylation of these binding partners (532). Receptor desensitization has been observed for a range of hormones including glucagon, FSH, human chorionic gonadotropin, and prostaglandins (533). Importantly, desensitization and down-regulation can occur in the same cells for the same receptor (534), and therefore, both can play a role in the production of NMDRCs.

5. Receptor competition

Mathematical modeling studies suggest that the mixture of endogenous hormones and EDCs establishes a natural environment to foster NMDRCs. Using mathematical models, Kohn and Melnick (42) proposed that when EDC exposures occur in the presence of endogenous hormone and unoccupied hormone receptors, some unoccupied receptors become bound with the EDC, leading to an increase in biological response (*i.e.* increased expression of a responsive gene, increased weight of an organ, *etc.*). At low concentrations, both the endogenous hormone and the EDC bind to receptors and activate this response, but at high doses, the EDC can outcompete the natural ligand. The model predicts that inverted U-shaped curves would occur regardless of the binding affinity of the EDC for the receptor and would be abolished only if the concentration of natural hormone were raised such that all receptors were bound.

6. Endocrine negative FEEDBACK loops

In several cases, the control of hormone synthesis is regulated by a series of positive- and negative feedback loops. Several hormones are known to control or influence their own secretion using these feedback systems. In one example, levels of insulin are known to regulate glucose uptake by cells. Blood glucose levels stimulate insulin production, and as insulin removes glucose from circulation, insulin levels decline. Thus, NMDRCs can occur as the free/available ligand and receptor concentrations are influenced by one another. In another example, thyroid hormone secretion is stimulated by TSH, and thyroid hormone suppresses TSH; thus, feedback between these two hormones allows thyroid hormone to be maintained in a narrow dose range.

Several studies indicate that these negative feedback loops could produce NMDRCs when the duration of hormone administration is changed (535). For example, short exposures of estrogen induce proliferation in the uterus and pituitary, but longer hormone regimens inhibit cell proliferation (236, 536). Thus, the outcome is one where exposure to a single hormone concentration stimulates an endpoint until negative feedback loops are induced and stimulation ends (537).

7. Other downstream mechanisms

Removing the variability that can come from examining different cell types, or even single cell types in the context of a tissue, studies of cultured cells indicate that different gene profiles are affected by low doses of hormone compared with higher doses. In a study of the genes affected by low *vs.* higher doses of estrogen, researchers found that there were a small number of genes in MCF7 breast cancer cells with very high sensitivity to low doses of estradiol (10 pM) compared with the total number of genes that were affected by higher (30 or 100 pM) exposures (538). But the surprising finding was the pattern of estradiol-induced *vs.* estradiol-suppressed gene expression at high and low doses; when 10 pM was administered, the number of estradiol-suppressible genes was approximately three times higher than the number of estradiol-inducible genes. However, the overall profile of the number of estradiol-suppressible genes was approximately half the total number of estradiol-inducible genes. This observation suggests that low doses of estrogen selectively target a small subset of the total number of estrogen-sensitive genes and that the genes affected by low doses are most likely to be suppressed by that treatment. The mechanisms describing how low doses of estrogen differently affect the expression of genes compared with higher doses have yet to be elucidated, but low doses of estradiol inhibit expression of apoptotic genes (539), indicating that which genes are affected by hormone exposure is relevant to understand how low doses influence cellular activities.

C. Examples of nonmonotonicity

1. Examples of NMDRCs from cell culture

A tremendous amount of theoretical and mathematical modeling has been conducted to understand the production of nonlinear and nonmonotonic responses (42, 540). These studies and others suggest that the total number of theoretical response curves is infinite. Yet this does not mean that the occurrence of NMDRCs is speculative; these types of responses are reported for a wide variety of chemicals. Cell culture experiments alone provide hundreds of examples of nonmonotonic responses (see Table 6 for examples). In the natural hormone category, many different hormones produce NMDRCs; this is clearly not a phenomenon that is solely attributable to estrogen and androgen, the hormones that have been afforded the most attention in the dose-response literature. Instead, NMDRCs are observed after cells are treated with a range of hormones, suggesting that this is a fundamental and general feature of hormones.

Chemicals from a large number of categories with variable effects on the endocrine system also produce NMDRCs in cultured cells. These chemicals range from components of plastics to pesticides to industrial chemicals and even heavy metals. The mechanisms for nonmonotonicity discussed in *Section III.B* are likely explanations for the NMDRCs reported in a range of cell types after exposure to hormones and EDCs. Table 6 provides only a small number of examples from the literature, and it should be noted that because these are studies of cells in culture, most of these studies typically examined only a few types of outcomes: cell number (which could capture the effects of a chemical on cell proliferation, apoptosis, or both), stimulation or release of another hormone, and regulation of target protein function, often examined by measuring the phosphorylation status of a target.

2. Examples of NMDRCs in animal studies

Some scientists suggest that nonmonotonicity is an artifact of cell culture, however, a large number of NMDRCs have been observed in animals after administration of natural hormones and EDCs, refuting the hypothesis that this is a cell-based phenomenon only. Similar to what has been observed in cultured cells, the NMDRCs observed in animals also span a large range of chemicals, model organisms, and affected endpoints (Table 7). These results underscore the biological importance of the mechanisms of nonmonotonicity that have been largely worked out *in vitro*.

Although NMDRCs attributable to estrogen treatment are well documented, the induction of NMDRCs is again observed to be a general feature of hormone treatment; a wide range of hormones produce these types of responses in exposed animals. Importantly, a number of pharmaceutical compounds with hormone-mimicking or endocrine-disrupting activities also produce NMDRCs. Finally, as expected from the results of cell culture

TABLE 6. Examples of NMDRCs in cell culture experiments

Chemicals by chemical class	Nonmonotonic effect	Cell type	Refs.
Natural hormones			
17β-Estradiol	Cell number	MCF7 breast cancer cells	135, 716
	Dopamine uptake	Fetal hypothalamic cells (primary)	717
	pERK levels, prolactin release	GH3/B6/F10 pituitary cells	41, 718, 719
	β-Hexosaminidase release	HMC-1 mast cells	720
	Cell number	Vascular smooth muscle cells	721
	Production of L-PGDS, a sleep-promoting substance	U251 glioma cells	722
5α-Dihydrotestosterone	Cell number	LNCaP-FGC prostate cancer cells	499
	Cell number, kinase activity	Vascular smooth muscle cells	721
5α-Androstenedione	Cell number	LNCaP-FGC prostate cancer cells	499
Corticosterone	Mitochrondrial oxidation, calcium flux	Cortical neurons (primary)	723
Insulin	Markers of apoptosis (in absence of glucose)	Pancreatic β-cells (primary)	724
Progesterone	Cell number	LNCaP-FGC prostate cancer cells	499
Prolactin	Testosterone release	Adult rat testicular cells (primary)	725
hCG	Testosterone release	Adult rat testicular cells (primary)	725
T_3	Rate of protein phosphorylation	Cerebral cortex cells (primary, synaptosomes)	726
	LPL mRNA expression	White adipocytes (rat primary)	727
GH	*IGF-I* expression	Hepatocytes (primary cultures from silver sea bream)	728
Pharmaceutical hormones			
DES	Cell number	MCF7 breast cancer cells	716
	Prolactin release	GH3/B6/F10 pituitary cells	41
Ethinyl estradiol	CXCL12 secretion	MCF7 breast cancer cells, T47D breast cancer cells	729
R1881 (synthetic androgen)	Cell number	LNCaP-FGC cells	499
Trenbolone	Induction of micronuclei	RTL-W1 fish liver cells	730
Plastics			
BPA	Cell number	MCF7 breast cancer cells	135, 716
	Dopamine efflux	PC12 rat tumor cells	40
	pERK levels, intracellular Ca^{2+} changes, prolactin release	GH3/B6/F10 pituitary cells	41, 718
	Cell number	LNCaP prostate cancer cells	731
DEHP	Number of colonies	*Escherichia coli* and *B. subtilis* bacteria	732
Di-*n*-octyl phthalate	Number of colonies	*E. coli* and *B. subtilis* bacteria	732
Detergents, surfactants			
Octylphenol	Cell number	MCF7 breast cancer cells	716
	Dopamine uptake	Fetal hypothalamic cells (primary)	717
	pERK levels	GH3/B6/F10 pituitary cells	718
	hCG-stimulated testosterone levels	Leydig cells (primary)	733
Propylphenol	pERK levels	GH3/B6/F10 pituitary cells	718
Nonylphenol	pERK levels, prolactin release	GH3/B6/F10 pituitary cells	41, 718
	β-Hexosaminidase release	HMC-1 mast cells	720
	Cell number	MCF7 breast cancer cells	135
PAH			
Phenanthrene	All-trans retinoic acid activity	P19 embryonic carcinoma cells	734, 735
Benz(a)acridine	All-trans retinoic acid activity	P19 embryonic carcinoma cells	734
Naphthalene	hCG-stimulated testosterone	Pieces of goldfish testes	736
Β-naphthoflavone	hCG-stimulated testosterone	Pieces of goldfish testes	736
Retene	hCG-stimulated testosterone	Pieces of goldfish testes	736
Heavy metals			
Lead	Estrogen, testosterone, and cortisol levels	Postvitellogenic follicles (isolated from catfish)	737
Cadmium	Expression of angiogenesis genes	Human endometrial endothelial cells	738

(*Continued*)

TABLE 6. Continued

Chemicals by chemical class	Nonmonotonic effect	Cell type	Refs.
Phytoestrogens and natural antioxidants			
Genistein	Cell number	Caco-2BBe colon adenocarcinoma cells	739
	CXCL12 secretion, cell number	T47D breast cancer cells	729
	Cell number, cell invasion, MMP-9 activity	PC3 prostate cancer cells	740
	pJNK levels, Ca^{2+} flux	GH3/B6/F10 pituitary cells	719
Coumesterol	Prolactin release, pERK levels	GH3/B6/F10 pituitary cells	719
Daidezin	Prolactin release, pERK levels	GH3/B6/F10 pituitary cells	719
	Cell number	MCF7 breast cancer cells	135
	Cell number	LoVo colon cancer cells	741
Resveratrol	Expression of angiogenesis genes	Human umbilical vein endothelial cells	742
Trans-resveratrol	pERK levels, Ca^{2+} flux	GH3/B6/F10 pituitary cells	719
Artelastochromene	Cell number	MCF7 breast cancer cells	743
Carpelastofuran	Cell number	MCF7 breast cancer cells	743
Biochanin A	Induction of estrogen-sensitive genes in the presence of testosterone	MCF7 breast cancer cells	744
Licoflavone C	Induction of estrogen-sensitive genes	Yeast bioassay	745
Quercetin	Aromatase activity	H295R adrenocortical carcinoma cells	746
	Cell number	SCC-25 oral squamous carcinoma cells	747
Dioxin			
TCDD	Cell number, gene expression	M13SV1 breast cells	748
PCB			
PCB-74	Cell viability, GnRH peptide levels	GT1-7 hypothalamic cells	749
PCB-118	Cell viability, GnRH peptide levels	GT1-7 hypothalamic cells	749
Aroclor 1242 (PCB mixture)	β-Hexosaminidase release	HMC-1 mast cells	720
POP mixture	Apoptosis of cumulus cells	Oocyte-cumulus complexes (primary, isolated from pigs)	750
Herbicides			
Glyphosphate-based herbicide (Round-Up)	Cell death, aromatase activity, ERβ activity	HepG2 liver cells	751
Atrazine	Cell number	IEC-6 intestinal cells	752
Insecticides			
Endosulfan	Cell number	IEC-6 intestinal cells	752
	β-Hexosaminidase release	HMC-1 mast cells	720
	ATPase activity of P-glycoprotein	CHO cell extracts	753
Diazinon	Cell number	IEC-6 intestinal cells	752
Dieldrin	β-Hexosaminidase release	HMC-1 mast cells	720
DDT	Cell number	MCF7 breast cancer cells	144
DDE	β-Hexosaminidase release	HMC-1 mast cells	720
	Prolactin release	GH3/B6/F10 pituitary cells	41
3-Methylsulfonyl-DDE	Cortisol and aldosterone release, expression of steroidogenic genes	H295R adrenocortical carcinoma cells	754
Fungicides			
Hexachlorobenzene	Transcriptional activity in the presence of DHT	PC3 prostate cancer cells	755
Prochloraz	Aldosterone, progesterone, and corticosterone levels; expression of steroidogenic genes	H295R adrenocortical cells	756
Ketoconazole	Aldosterone secretion	H295R adrenocortical cells	757
Fungicide mixtures	Aldosterone secretion	H295R adrenocortical cells	757
PBDE			
PBDE-49	Activation of ryanodine receptor 1	HEK293 cell (membranes)	758
PBDE-99	Expression of *GAP43*	Cerebral cortex cells (primary)	759

Due to space concerns, we have not elaborated on the shape of the curve (U, inverted U, or other nonmonotonic shape) or the magnitude of observed effects in this table. CXCL12, Chemokine (C-X-C motif) ligand 12; DEHP, bis(2-ethylhexyl) phthalate; DHT, dihydrotestosterone; hCG, human chorionic gonadotropin; MMP, matrix metalloproteinase; PAH, polyaromatic hydrocarbons; PBDE, polybrominated diphenyl ethers; PCB, polychlorinated biphenyl; pERK, phospho-ERK; PGDS, prostaglandin-D synthase; pJNK, phospho-c-Jun N-terminal kinase.

TABLE 7. Examples of NMDRCs in animal studies

Chemicals by chemical class	Nonmonotonic effect	Organ/sex/animal	Refs.
Natural hormones			
17β-Estradiol	Morphological parameters	Mammary gland/female/mice	138, 541
	Accumulation of cAMP	Pineal/female/rats	760
	Prostate weight	male/mice	689
	Uterine weight	female/mice	761
	Antidepressant effects, measured by immobility assay	Behavior/male/mice	762
	Nocturnal activity, gene expression in preoptic area	Brain and behavior/female/mice	763
Corticosterone	Spatial memory errors	Behavior/male/rats	764
	Cholinergic fiber loss in cortex after treatment with neurodegenerative drugs	Brain/male/rats	765
	Mitochondrial metabolism	Muscle/male/rats: strain differences	766
	Contextual fear conditioning	Behavior/male/rats	767
	Locomotor activity	Behavior/male/captive Adelie penguins	768
Glucocorticoid	Na$^+$/K$^+$-ATPase activity	Brain/tilapia (fish)	769
Testosterone	Na$^+$/K$^+$-ATPase activity	Brain/tilapia (fish)	769
	Gonadotropin subunit gene expression	Pituitary/sexually immature goldfish	770
11β-Hydroxyandrosterone	Gonadotropin subunit gene expression	Pituitary/sexually immature goldfish	770
T_4	Bone growth	Tibia/male/rats with induced hypothyroidism	771
Leptin	Insulin production (in the presence of glucose)	Pancreas/male/rats	560
Oxytocin	Infarct size, plasma LDH levels, creatine kinase activity after ischemia/ reperfusion injury	Brain and blood/male/rats	772
	Memory retention	Behavior/male/mice	773
Melatonin	Brain infarction and surviving neuron number after injury	Brain/female/rats	774
Dopamine	Memory	Brain/both/rhesus monkey	775
	Neuronal firing rate	Brain/male/rhesus monkey	776
Pharmaceutical			
DES	Sex ratio, neonatal body weight, other neonatal development	Mice	777
	Adult prostate weight	Male/mice	689
	Uterine weight	Female/mice	761
	Expression of PDGF receptor	Testes/male/rats	778
	Morphological parameters	Mammary gland/male and female/ mice	779
Estradiol benzoate	Dorsal prostate weight, body weight	Male/rats	780
	Sexual behaviors, testes morphology	Male/zebra finches (birds)	781
Ethinyl estradiol	GnRH neurons	Brain/zebrafish	782
Tamoxifen	Uterine weight	Female/mice	761
Fluoxetine (antidepressant)	Embryo number	*Potamopyrgus antipodarum* (snails)	783
Fadrozole (aromatase inhibitor)	Aromatase activity	Ovary/female/fathead minnows	784
Plastics			
BPA	Fertility	Reproductive axis /female/mice	316
	Reproductive behaviors	Behavior/male/rats	785
	Protein expression	Hepatopancreas/male/*Porcellio scaber* (isopod)	786
	Timing of vaginal opening, tissue organization of uterus	Reproductive axis/female/mice	577
	Expression of receptors in embryos	Brain and gonad/both/ mice	787
DEHP	Aromatase activity	Hypothalamus/male/rats	788
	Cholesterol levels	Serum/male/rats	569
	Timing of puberty	Reproductive axis /male/rats	789
	Body weight at birth, vaginal opening, and first estrous	Female/rats	790
	Seminal vesicle weight, epididymal weight, testicular expression of steroidogenesis genes	Male/rats	791
	Responses to allergens, chemokine expression	Skin/male/mice	792

(*Continued*)

TABLE 7. Continued

Chemicals by chemical class	Nonmonotonic effect	Organ/sex/animal	Refs.
Detergents, surfactants			
Nonylphenol ethoxylate	Fecundity	*Biomphalaria tenagophila* (snails)	793
Octylphenol	Embryo production	*P. antipodarum* (snails)	794
	Spawning mass and egg numbers	*Marisa cornuarietis* (snails)	795
Semicarbazide	Timing of preputial separation, serum DHT	Male/rats	796
Antimicrobial			
Triclocarban	Fecundity	*P. antipodarum* (snails)	797
PCB			
Mixture of PCB	Corticosterone levels	Male/kestrels (birds)	798
Environmental PCB mixture	Corticosterone levels	Female/tree swallows (birds)	799
UV filters			
Octyl methoxycinnamate	Activity, memory	Behavior/both/rats	800
Aromatic hydrocarbons			
B-naphthoflavone	Testosterone	Plasma/male/goldfish	736
Toluene	Locomotor activity	Behavior/male/rats	801
Dioxins			
TCDD	Cell-mediated immunity	Immune system/male/ rats	802
	Proliferation after treatment with chemical carcinogen	Liver/female/rats	803
Heavy metals			
Cadmium	Expression of metallothionein, *pS2/TFF1*	Intestine and kidney/ female/rats	804
	Activity of antioxidant enzymes	Earthworms	805
	Size parameters, metamorphic parameters	*Xenopus laevis*	806
Lead	Growth, gene expression	*Vicia faba* seedlings (plant)	807
	Retinal neurogenesis	Eye and brain/female/rats	808
Selenium	DNA damage, apoptotic index	Prostate/male/dogs	809
	Hatching failure	Eggs/red-winged blackbirds (wild population)	810
Phytoestrogens			
Genistein	Aggressive, defensive behaviors	Behavior/male/mice	811
	Retention of cancellous bone after ovariectomy	Tibia bones/female/rat	812
	Expression of *OPN*, activation of Akt	Prostate/male/mice	740
Resveratrol	Angiogenesis	Chorioallantoic membrane/chicken embryos	742
	Ulcer index after chemical treatment, expression of gastroprotective genes	Stomach/male/mice	813
Phytochemicals			
Phlorizin	Memory retention	Behavior/male/mice	814
Herbicides			
Atrazine	Time to metamorphosis	Thyroid axis/*Rhinella arenarum* (South American toad)	815
	Survivorship patterns	Four species of frogs	363
	Growth parameters	*Bufo americanus*	816
Pendimethalin	Expression of *AR*, *IGF-I*	Uterus/female/mice	817
Commercial mixture with mecoprop, 2,4-dichlorophenoxyacetic acid and dicamba	Number of implantation sites, number of live births	Female/mice	818
Simazine	Estrous cyclicity	Reproductive axis/female/rat	819
Insecticides			
Permethrin	Dopamine transport	Brain/male/mice	820
Heptachlor	Dopamine transport	Brain/male/mice	820
DDT	Number of pups, sex ratios, neonatal body weight, male anogenital distance	Mice	777
Methoxychlor	Number of pups, anogenital distance (males and females), neurobehaviors (males and females)	Mice	777
Chlorpyrifos	Body weight	Male/rats	821
	Antioxidant enzyme activity	*Oxya chinensis* (locusts)	822
Malathion	Antioxidant enzyme activity	*O. chinensis* (locusts)	822

(*Continued*)

TABLE 7. Continued

Chemicals by chemical class	Nonmonotonic effect	Organ/sex/animal	Refs.
Fungicides			
Carbendazim	Liver enzymes, hematology parameters	Blood and liver/male/rats	823
Chlorothalonil	Survival, immune response, corticosterone levels	Several amphibian species	686
Vinclozolin	Protein expression	Testes/male/*P. scaber* (isopod)	786

Due to space concerns, we have not elaborated on the shape of the curve (U, inverted U, or other nonmonotonic shape) or the magnitude of observed effects in this table. DEHP, Bis(2-ethylhexyl) phthalate; DHT, dihydrotestosterone; LDH, lactate dehydrogenase; PCB, polychlorinated biphenyl; PDGF, platelet-derived growth factor.

experiments, chemicals with many different modes of action generate NMDRCs in treated animals.

Perhaps most striking is the range of endpoints affected, from higher-order events such as the number of viable offspring (which could be due to alterations in the reproductive tissues themselves or the reproductive axis), to behavioral effects, to altered organ weights, and to lower-order events such as gene expression. The mechanisms responsible for these nonmonotonic phenomena may be similar to those studied in cell culture systems, although additional mechanisms are likely to be operating *in vivo* such as alterations in tissue organization (541) and the interactions of various players in the positive and negative feedback loops of the endocrine system.

3. Examples of NMDRCs in the epidemiology literature

Perhaps not surprisingly, natural hormones produce NMDRCs in human populations as well (Table 8). Although the methods needed to detect NMDRCs in humans are specific to the field of epidemiology, these results sup-

TABLE 8. NMDRCs for natural hormones identified in the epidemiology literature

Hormone	Affected endpoint	NMDRC	Study subjects	Refs.
Testosterone (free)	Incidence of coronary events	Incidence of 25% at extremes of exposure, 16% at moderate exposure	Rancho Bernardo Study participants, women aged 40+ (n = 639)	824
	Depression	Hypo- and hypergonadal had higher depression scores than those with intermediate free testosterone	Androx Vienna Municipality Study participants, manual workers, men aged 43–67 (n = 689)	825
PTH	Mortality	~50% excess risk for individuals with low or high iPTH	Hemodialysis patients (n = 3946)	826
	Risk of vertebral or hip fractures	~33% higher for low or high iPTH compared to normal levels	Elderly dialysis patients (n = 9007)	827
TSH	Incidence of Alzheimer's disease	About double the incidence in lowest and highest tertile in women (no effects observed in men)	Framingham Study participants (elderly) (n = 1864, 59% women)	828
Leptin	Mortality	Mortality ~10% higher for lowest and highest leptin levels	Framingham Heart Study participants (elderly) (n = 818, 62% women)	563
Insulin	Coronary artery calcification	Higher for low and high insulin area under the curve measures.	Nondiabetic patients with suspected coronary heart disease, cross-sectional (n = 582)	829
	Mortality (noncardiovascular only)	Relative risk ~1.5 for highest and lowest fasting insulin levels	Helsinki Policemen Study participants, men aged 34–64 (n = 970)	830
Cortisol	BMI, waist circumference	Low cortisol secretion per hour for individuals with highest and lowest BMI, waist circumference	Whitehall II participants, adults, cross-sectional (n = 2915 men; n = 1041 women)	831
	Major depression (by diagnostic interview)	Slight increases at extremes of cortisol	Longitudinal Aging Study Amsterdam participants, aged 65+, cross-sectional (n = 1185)	832

BMI, Body mass index; iPTH, intact PTH; PTH, parathyroid hormone.

port the idea that NMDRCs are a fundamental feature of hormones. Importantly, it should be noted that most of the individuals surveyed in studies examining the effects of natural hormones have a disease status or are elderly. This of course does not mean that natural hormones induce NMDRCs in only these select populations but may instead be a reflection of the types of individuals available for these studies (for example, there are very few clinical events in younger people).

NMDRCs observed in the epidemiology literature from human populations exposed to EDCs are now starting to receive attention (Table 9). Here, most reports of NMDRCs come from studies of healthy individuals exposed to persistent organic pollutants POPs, chemicals that do not easily degrade and consequently bioaccumulate in human and animal tissues (542). These POPs do encompass a range of chemical classes including components of plastics, pesticides, and industrial pollutants. A large number of these studies have focused on endpoints that are relevant to metabolic disease, and together, these studies show that there is a recurring pattern of NMDRCs related to POPs and disease. Of course, not every study of POPs shows NMDRCs, and this is probably due to the distribution of EDCs in the populations examined.

In addition to the studies that show strong evidence for NMDRCs in human populations, there is also a subset of studies that provide suggestive evidence for nonmonotonic relationships between EDCs and human health endpoints (Table 9). In fact, the authors of many of these papers clearly identify U- or inverted U-shaped dose-response curves. However, when authors do not perform the appropriate statistical tests to verify the presence of a NMDRC, there is some ambiguity in their conclusions. The usual cross-sectional *vs.* prospective design dichotomy in epidemiology also is a factor that can influence the strength of a NMDRC, or prevent the detection of one at all. This disjunction in design is often incongruous with EDC exposure studies because we often know very little about clearance rates of the chemical, interactions with adiposity, and changes to these factors with age and gender. Yet regardless of any possible weaknesses in these studies, they provide supportive evidence that NMDRCs are observed in human populations.

Because these reports of NMDRCs in human populations are relatively new, few mechanisms have been proposed for these phenomena. Why would risk curves be nonmonotonic over the dose distribution observed in human populations? Why would individuals with the highest exposures have less severe health outcomes compared with individuals with more moderate exposures? One plausible explanation is that the same mechanisms for NMDRCs in animals and cell cultures operate in human populations: chronic exposures to high doses can activate negative feedback loops, activate receptors that promote changes in different pathways that diverge on the same endpoint with opposing effects, or produce some measure of toxicity. Accidental exposures of very large doses may not behave the same as background doses for a variety of reasons, including the toxicity of high doses; these large doses tend to occur over a short time (and therefore more faithfully replicate what is observed in animal studies after controlled administration).

Another explanation is that epidemiology studies, unlike controlled animal studies, examine truly complex mixtures of EDCs and other environmental chemicals. Some chemical exposures are likely to be correlated due to their sources and their dynamics in air, water, soil, and living organisms that are subsequently eaten. Therefore, intake of these chemicals may produce unpredicted, likely nonlinear outcomes whether the two chemicals act via similar or different pathways.

The design of observational epidemiological studies is fundamentally different from studies of cells or animals, in that the EDC exposure distributions are given, rather than set by the investigator. In particular, as shown in Fig. 5, different epidemiological populations will have different ranges of exposure, with the schematic example showing increasing risk in a population with the lowest exposures (labeled group A), an inverted U-shaped risk in a moderate dose population (labeled group B), and an inverse risk in a population with the highest exposures (labeled group C). An additional example is provided (labeled group D) in which an industrial spill shows high risk, but the comparison with the entire unaffected population with a wide variety of risk levels due to differential background exposure could lead to a high- or a low-risk reference group and a wide variety of possible findings.

It is reasonable to suggest that even though epidemiological studies are an assessment of exposures at a single time point, many of these pollutants are persistent, and therefore a single measure of their concentration in blood may be a suitable surrogate for long-term exposures. The movement of people from relatively low- to higher-exposure groups over time depend on refreshed exposures, clearance rates, and individual differences in ability to handle exposures (*i.e.* due to genetic susceptibilities, amount of adipose tissue where POPs can be stored, *etc.*).

Figure 5 therefore further illustrates that observational epidemiological studies yield the composite effect of varying mixtures of EDCs at various exposure levels for various durations, combining acute and chronic effects. These studies are important, however, in that they are the only way to study EDC effects in the long term in intact humans, as opposed to studying signaling pathways, cells,

TABLE 9. NMDRCs for EDCs identified in the epidemiology literature

Chemicals by chemical class	Affected endpoint	NMDRC	Study subjects	Refs.
Insecticides				
Trans-nonachlor	Diabetes incidence	Highest risk in groups with intermediate exposures (quartile 2)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
	Telomere length in peripheral leukocytes	Increased length in intermediate exposures (quintile 4)	Adults aged 40+ (Korea, n = 84)	591
p,p′-DDE	BMI, triglyceride levels, HDL cholesterol	Highest risk in groups with intermediate exposures (quartile 3)	CARDIA participants (n = 90 controls from nested case control study)	590
	Risk of rapid infant weight gain	For infants born to women of normal weight prepregnancy, risk is highest with intermediate exposures.	Infants from Childhood and the Environment project, Spain (n = 374 from normal prepregnancy weight mothers; n = 144 from overweight mothers)	834
	Telomere length in peripheral leukocytes	Increased length with intermediate exposures (quintile 4)	Adults aged 40+ (Korea, n = 84)	591
Oxychlordane	Bone mineral density of arm bones	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density.	NHANES 1999–2004 participants, aged 50+ (n = 679 women, n = 612 men)	835
Plastics				
Mono-methyl phthalate (MMP)	Atherosclerotic plaques	Increased risk in intermediate exposure groups (quintiles 2–4)	Adults aged 70, living in Sweden (n = 1016)	836
Perfluorinated compounds				
PFOA	Arthritis (self-reported)	Increased risk in intermediate exposure groups (quartile 2)	NHANES participants, aged 20+ (both sexes, n = 1006)	837
Fire retardants				
PBB-153	Blood triglyceride levels	Increased risk in intermediate exposure groups (quartile 2)	NHANES participants, aged 12+ (n = 637)	604
PBDE-153	Prevalence of diabetes,	Prevalence of diabetes highest in intermediate groups (quartiles 2–3 relative to individuals with undetectable levels)	NHANES participants, aged 12+ (n = 1367)	604
	Prevalence of metabolic syndrome, levels of blood triglycerides	Prevalence of metabolic syndrome highest in intermediate exposure groups (quartile 2 relative to individuals with undetectable levels); blood triglycerides highest in low exposure groups (quartile 1 relative to individuals with undetectable levels)	NHANES participants, aged 12+ (n = 637)	604
PCB				
PCB-74	Triglyceride levels	Lowest levels are observed in intermediate groups (quartile 2)	CARDIA participants (n = 90 controls from nested case-control study)	590
PCB-126	Bone mineral density in right arm	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density	NHANES participants, aged <50 (n = 710 women, n = 768 men)	835
PCB-138	Bone mineral density in right arm	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density	NHANES participants, women aged 50+ (n = 679 women, n = 612 men)	835
PCB-153	Telomere length in peripheral leukocytes	Increased length with intermediate exposure groups (quintile 4)	Adults aged 40+ (Korea, n = 84)	591
PCB-170	Diabetes incidence	Highest risk in groups with intermediate exposures (quartile 2)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
	Endometriosis	Decreased risk in groups with intermediate exposures (quartile 3)	Participants from the Women at Risk of Endometriosis (WREN) study, 18–49 yr old, case-control study (n = 251 cases; n = 538 controls)	838
PCB-172	DNA hypomethylation (by Alu assay)	Highest levels of hypomethylation in groups with lowest and highest exposures	Adults aged 40+ (Korea, n = 86)	839
PCB-180[a]	BMI	Highest BMI with intermediate exposures (quartile 2)	CARDIA participants (n = 90 controls from nested case control study)	590
PCB-187[a]	HDL cholesterol levels	Lowest levels with intermediate exposures (quartile 2)	CARDIA participants (n = 90 controls from nested case control study)	590
PCB 196–203	Diabetes incidence	Highest risk in groups with intermediate exposures (quartile 2)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
PCB-196	Endometriosis	Decreased risk in groups with intermediate exposures (quartile 3)	Participants from the Women at Risk of Endometriosis (WREN) study, 18–49 yr old, case-control study (n = 251 cases; n = 538 controls)	838

(*Continued*)

TABLE 9. Continued

Chemicals by chemical class	Affected endpoint	NMDRC	Study subjects	Refs.
PCB-199[a]	Triglyceride levels	Highest risk in groups with intermediate exposures (quartiles 2–3)	CARDIA participants (n = 90 controls from nested case control study)	590
PCB-201	Endometriosis	Decreased risk in groups with intermediate exposures (quartiles 2–3)	Participants from the Women at Risk of Endometriosis (WREN) study, 18–49 yr old, case-control study (n = 251 cases, n = 538 controls)	838
Heavy metals				
Selenium	Fasting glucose levels (by modeled exposure)	Intermediate exposures have highest fasting glucose levels	NHANES 2003- 2004 participants, aged 40+ (n = 917)	840
	Glycosylated hemoglobin (by modeled exposure)	Intermediate exposures have highest % glycosylated hemoglobin	NHANES 2003- 2004 participants, aged 40+ (n = 917)	840
	Diabetes incidence (by modeled exposure)	Intermediate exposures have highest risk for diabetes	NHANES 2003- 2004 participants, aged 40+ (n = 917)	840
	Blood triglyceride levels	Intermediate exposures have highest triglyceride levels	NHANES participants, aged 40+ (n = 1159)	841
Arsenic	Cytokines in umbilical cord blood	Lower inflammatory markers at intermediate exposures (quartile 2)	Pregnant women in Bangladesh (n = 130)	842
Manganese	Mental development scores in infants and toddlers	Intermediate exposures had highest mental development scores at 12 months of age; association lost in older toddlers	12-month-old infants, Mexico (n = 301)	843
	Sperm count, motility and morphology	Intermediate doses had lowest sperm counts and motility; intermediate doses also had the worst sperm morphologies	Men aged 18–55 (infertility clinic patients, n = 200)	844
Mixtures				
31 POP	Diabetes incidence	Highest incidence in intermediate groups (sextiles 2–3)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
16 POP	Diabetes incidence	Highest incidence in intermediate groups (sextiles 2–3)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
Non-dioxin-like PCB (mix)	Metabolic syndrome	Highest incidence in intermediate groups (quartile 3)	NHANES 1999–2002 participants, aged 20+ (n = 721)	845
Dioxin-like PCB (mix)	Triacylglycerol levels by quartile of exposure	Highest levels in intermediate groups (quartile 3)	NHANES 1999–2002 participants, aged 20+ (n = 721)	845
Additional supportive evidence for NMDRC in the epidemiology literature				
Insecticides				
Heptachlor epoxide	Prevalence of newly diagnosed hypertension	Highest risk in intermediate groups (quartile 2); other endpoints do not have NMDRC	NHANES participants, women aged 40+, cross-sectional (n = 51 cases, n = 278 total)	826
β-Hexachloro-cyclohexane	Triacylglycerol levels by quartile of exposure	Highest risk in intermediate group (quartile 2)	NHANES participants, aged 20+ (n = 896 men, 175 with metabolic syndrome)	845
Plastics				
Mono-*N*-butyl phthalate (MBP)	BMI, age-specific effects	Effects seen only in elderly participants (age 60–80); risk is lowest in quartile 3	NHANES male participants (n = 365; age 60–80)	470
Mono-benzyl phthalate (MBzP)	BMI, age-specific effects	Effects seen only in young participants (age 6–11); risk is highest in quartiles 2–3	NHANES participants (both sexes, n = 329 males; n = 327 females)	470
Flame retardants				
PFOA	Thyroid disease (self-reported)	Lowest risk in intermediate groups (quartile 3)	NHANES 1999–2000, 2003–2006 participants, males aged 20+ (n = 3974)	837
Dioxin and related compounds				
TCDD	Age at natural menopause	Highest for intermediate exposure group (quintile 4)	Highly exposed women; Seveso Women's Health Study participants (n = 616)	468
HCDD	Bone mineral density in right arm by quintile of fat mass	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density	NHANES participants, women aged 50+ (n = 679 women, n = 612 men)	835
Heavy metals				
Selenium	Prevalence of peripheral artery disease	Disease prevalence decreased in intermediate doses, then increased gradually with higher doses	NHANES participants, aged 40+ (n = 2062)	469

BMI, Body mass index; HCDD, hexachloro-dibenzo-p-dioxin; HDL, high-density lipoprotein. PCB, polychlorinated biphenyls; PFOA, perfluorooctanoic acid; PBB, polybrominated biphenyl; PBDE, polybrominated diphenyl ethers; POP, persistent organic pollutants

[a] In many cases, multiple chemicals in the same class had similar effects. A few chemicals were selected to illustrate the observed effect. This list is not comprehensive.

organs, or animal models over limited periods of time. Causal inference is not done directly from the epidemiological study results; instead, it is done via combining information from the epidemiological observations with findings from the detailed studies of pathways and animals.

We have suggested that NMDRCs are a fundamental and general feature of hormone action in cells and animals.

Figure 5.

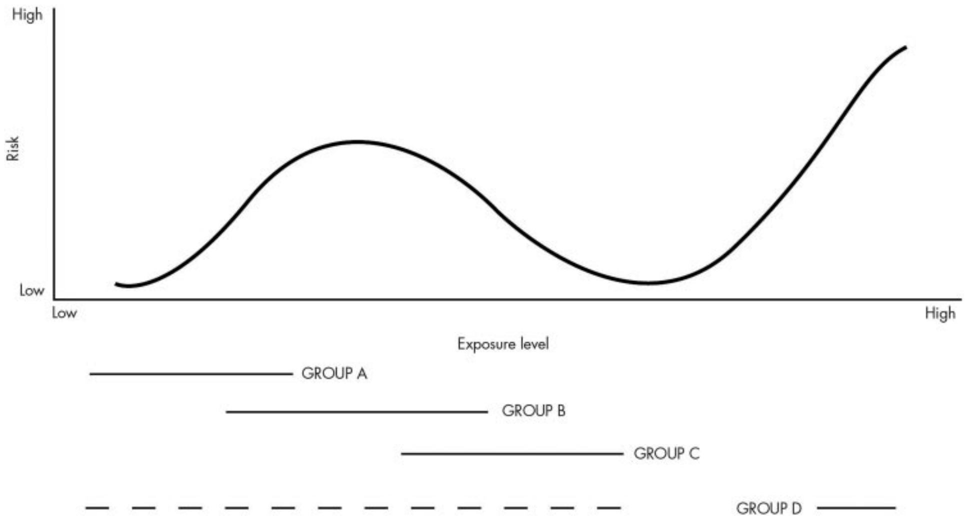

Figure 5. Example of a NMDRC in humans and the sampling populations that could be examined in epidemiology studies. This schematic illustrates a theoretical NMDRC in a human population. If a study were to sample only group A, the conclusion would be that with increasing exposures, risk increases monotonically. Sampling group B would allow researchers to conclude that there is a nonmonotonic relationship between exposure level and risk. If a study included only group C, the conclusion would be that with increasing exposures, there is decreased risk of disease. Group D represents a population that was highly exposed, *i.e.* due to an industrial accident. This group has the highest risk, and there is a monotonic relationship between exposures and risk, although risk is high for all individuals. In the group D situation, there is generally a background population with which high-dose exposure is compared (*dotted line*); relative risk for group D would depend on whether that background population resembles group A, B, or C. From this example, it is clear that the population sampled could strongly influence the shape of the dose-response curve produced as well as the conclusions reached by the study.

It is therefore worth asking whether NMDRCs are expected in the epidemiology literature. The endpoints assessed in epidemiology studies are typically integrated effects, rather than short-term effects; therefore, the various cell- or organ-specific effects may cancel each other, particularly if they are NMDRCs (because they are unlikely to all have nonmonotonicity at the same dose and direction). Thus, NMDRCs are likely to be rarer in the epidemiology literature compared with studies examining the effects of a wide range of doses of an EDC on animals and cultured cells. Yet it is also important to ask what can be concluded if a NMDRC is detected in one epidemiology study but not in others examining the same chemical and outcome. There are several factors that must be considered. The first is that differences in the populations examined between the two studies could explain why a monotonic relationship is observed in one group and a nonmonotonic relationship in another (see Fig. 5). The second is that one or more studies may not be statistically designed to detect NMDRCs. Finally, it is plausible that the NMDRC is an artifact due to residual confounding or some other factor that was not considered in the experimental design. As more becomes known about the mechanisms operating in cells, tissues, and organs to generate NMDRCs, our ability to apply this information to epidemiology studies will increase as well.

4. Tamoxifen flare, a NMDRC observed in cells, animals, and human patients

Although there is controversy in toxicology and risk assessment for endocrine disruptors, NMDRCs are recognized and used in current human clinical practice, although under a different specific term, flare. Flare is often reported in the therapy of hormone-dependent cancers such as breast and prostate cancer. Clinically, failure to recognize the NMDRC that is termed a flare would be considered malpractice in human medicine.

Tamoxifen flare was described and named as a transient worsening of the symptoms of advanced breast cancer, particularly metastases to bone associated with increased pain, seen shortly after the initiation of therapy in some patients (543). If the therapy could be continued, the patients showing tamoxifen flare demonstrated a very high likelihood of subsequent response to tamoxifen, including arrest of tumor growth and progression of symptoms for some time.

The subsequent mechanism of the flare was described in basic lab studies in athymic mouse models of human hormone-dependent breast cancer xenografts (544) and in tissue culture of hormone-dependent human breast cancer cells (545–547). In these models, it was observed that although high, therapeutic concentrations of tamoxifen inhibited estrogen-stimulated proliferation of breast cancer cells, lower concentrations of tamoxifen actually stimulated breast can-

Figure 6.

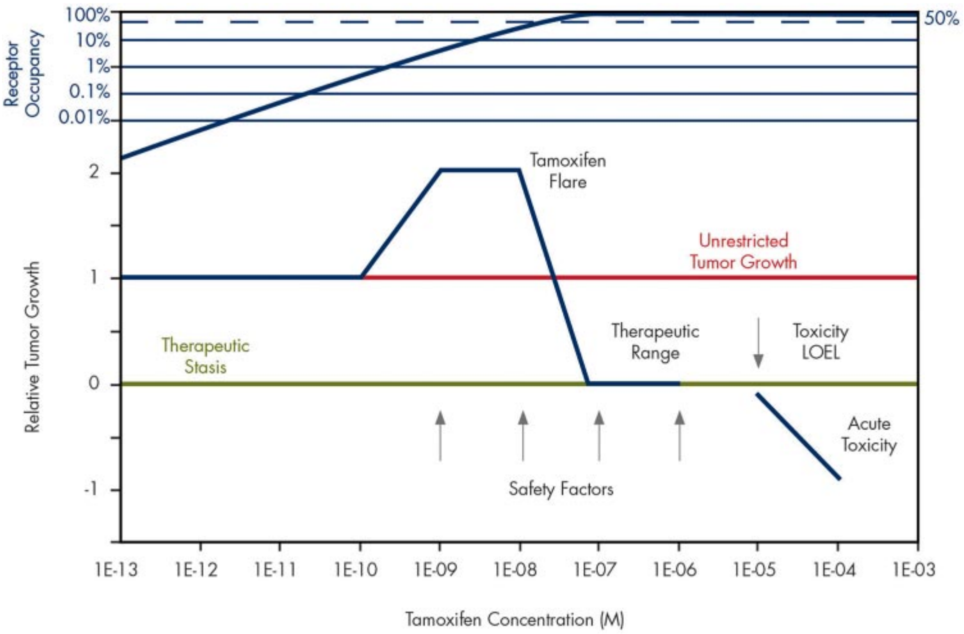

Figure 6. Dose-response ranges for tamoxifen in breast cancer therapy. This figure demonstrates the NMDRC, also called flare, in tamoxifen treatments. As the circulating dose of tamoxifen increases when treatment starts, patients initially experience flare, *i.e.* growth of the tumor (546), followed by a decrease in tumor size as the circulating levels of tamoxifen rise into the therapeutic range (676, 677). High doses of tamoxifen are acutely toxic (546). Starting from the highest concentrations, where acute toxicity is observed, and going to lower concentrations on the X-axis, the acute toxicity diminishes towards zero growth, *i.e.* therapeutic stasis (*green* baseline). This occurs at approximately 1E-05 m, the lowest observed effect level (LOEL) for toxicity. The vertical arrows show the results of applying three or four 10-fold safety factors to the LOEL for the high-dose toxicity of tamoxifen, and would calculate a safe or reference dose for tamoxifen in the region of flare, the least safe region of exposure in actual practice. Above the diagram of dose response ranges is estimated ER occupancy by tamoxifen. This was calculated from the affinity constant of tamoxifen for ERs determined in human breast cancer cells (Ki = 29.1 nM; Ref 678); flare appears to correspond to low receptor occupancy (*blue axis*), therapeutic range with mid and upper-range receptor occupancy, and acute toxicity well above 99% receptor occupancy. (678).

cer cell growth as long as the cells were estrogen dependent (548). Tamoxifen was also shown to disrupt tissue organization of the mammary gland, with specific effects on the stroma that may contribute to the observed effects on proliferation of epithelial cells (549, 550).

Tamoxifen therapy is administered as 10 mg twice per day (20 mg/d; approx 0.3 mg/kg body weight per day), but the target circulating levels are in the near submicromolar range (0.2–0.6 μM); these levels are reached slowly, after approximately 2 wks of therapy (551). In the initial period, where tamoxifen flare is observed, the circulating concentrations are ascending through lower concentrations, in the range below therapeutic suppression of growth, where breast cancer cell proliferation is actually stimulated by the drug, both in tissue culture, in animal xenograft studies, and in human patients (reviewed in Ref. 548). The recognition of this dual dose-response range for tamoxifen (low-dose, low-concentration estrogenic growth-stimulatory and higher-dose, higher-concentration estrogenic growth-inhibitory responses) led to the definition of the term selective estrogen response modulator, or SERM, activity (552–554). This SERM activity has since been observed for many or even most estrogenic EDCs, including BPA (3, 555–557).

These observations defined three separate dose-response ranges for the SERM tamoxifen in human clinical use. The lowest dose-response range, the range of flare, stimulated breast cancer growth and symptoms in some patients with hormone-dependent cancer. The next higher dose-response range is the therapeutic range where tamoxifen inhibits estrogen-dependent tumor growth. The highest dose range causes acute toxicity by the SERM (see Fig. 6).

Tamoxifen provides an excellent example for how high-dose testing cannot be used to predict the effects of low doses. For tamoxifen (as for other drugs), the range of acute human toxicity for tamoxifen was determined in phase I clinical trials. Phase I trials also defined an initial therapeutic range, the second dose-response range, as a dose below which acute toxicity was not observed. The therapeutic dose range was tested and further defined in phase II and later clinical trials to determine efficacy (see for example Ref. 558). Standard toxicological testing from

Figure 7.

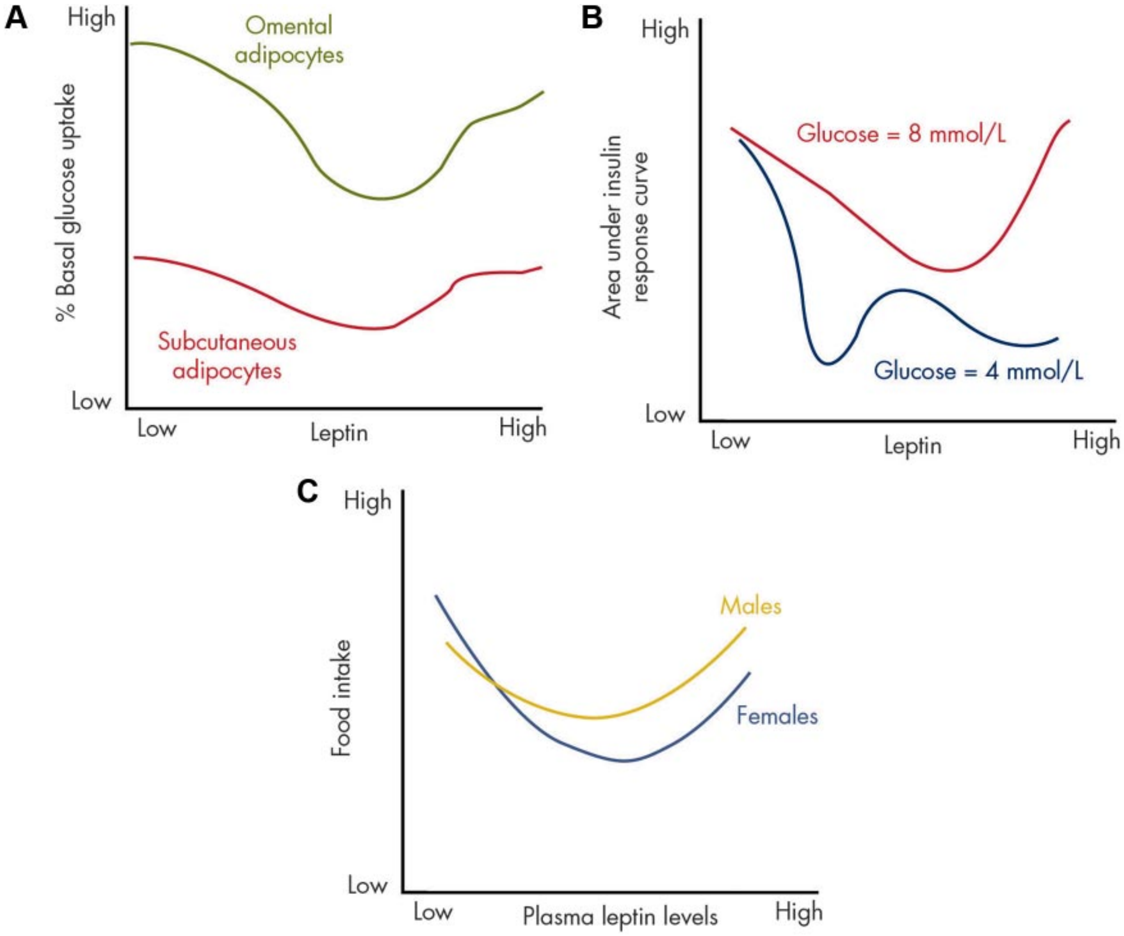

Figure 7. Leptin as an example of a NMDRC. Several studies report NMDRCs in response to leptin treatments. A, NMDRCs are observed in cultured primary adipocytes after leptin exposure. This graph illustrates the relationship between administered leptin dose and glucose uptake in two types of adipocytes, those isolated from omental tissue (*green*) and others from sc fat (*purple*) (schematic was made from data in Ref. 559). These data are on a log-linear plot. B, *Ex vivo* rat pancreas was treated with leptin and various doses of glucose, and the insulin response curves were examined. Area under the curve is a measure of the ability of the pancreas to bring glucose levels under control. Different dose-response curves were observed depending on the amount of glucose administered: a U-shaped curve when 8 mmol/liter was included (*pink*) or a multiphasic curve with 4 mmol/liter (*blue*) (schematic made from data in Ref. 560). These data are on a linear-linear plot. C, U-shaped NMDRCs were also observed when food intake was compared with leptin levels in the blood of rats administered the hormone. This response was similar in males (*orange*) and females (*cyan*) (schematic made from data in Ref. 562). These data are on a linear-linear plot.

high doses to define a LOAEL or NOAEL are equivalent to the phase I clinical testing, and in risk assessment, a safe dose or reference dose is calculated from these tests. However, the lowest dose range, with the highly adverse effects termed flare, was not detected in the phase I trials and was determined only for tamoxifen in breast cancer therapy at the therapeutic doses (543). The implication for risk assessment is that NMDRCs for EDCs, particularly those already identified as SERMs, would likely not be detected by standard toxicological testing at high doses. That is, the consequence of high-dose testing is the calculation of a defined but otherwise untested safe dose that is well within the range equivalent to flare, *i.e.* a manifestly unsafe dose of the EDC (Fig. 6).

5. Similarities in endpoints across cell culture, animal, and epidemiology studies: evidence for common mechanisms?

There are common trends in some findings of NMDRCs in cell, animal, and human studies and therefore evidence for related mechanisms for NMDRCs at various levels of biological complexity. Tamoxifen flare, discussed in *Section III.C.4*, is an informative example. Another illustrative example is that of the effect of the hormone leptin (Fig. 7). In cultured primary adipocytes, NMDRCs are observed after leptin exposure; moderate doses of leptin significantly reduce insulin-mediated glucose intake, whereas low and high doses maintain higher glucose intake in response to insulin (559). The rat pancreas shows a similar response to leptin; the amount of secreted insulin has an inverted U-shaped response to leptin (560, 561). Even more striking is the relationship between leptin and food intake. Rats administered moderate doses of leptin consume less food compared to rats dosed with low or high levels of leptin (562); mechanistically, this lower food intake could be due to higher circulating glucose levels in these animals due to ineffective insulin action. And finally, in a human study, leptin levels were found to correlate with body mass index but have a U-shaped relationship with mortality (563). These results suggest that hormones can produce similar responses at several levels of biological complexity (cell, organ, animal, and population).

A large number of epidemiology studies with NMDRCs have found relationships between EDC exposures like POPs and metabolic diseases including obesity and diabetes (Table 9) (see also Ref. 564 for a review), and the mechanisms for these relationships have begun to be explored. Human and animal cells treated with EDCs in culture display NMDRCs that are relevant to these diseases: BPA has nonmonotonic effects on the expression of adipocyte proteins in preadipocytes and the release of adiponectin from mature adipocytes (565–567). Similarly, in female rodents, low doses but not high doses of BPA increased adipose tissue weight and serum leptin concentrations (568), and intermediate doses of phthalates decrease serum cholesterol levels (569). Thus, although understanding the mechanisms operating at the cellular level of organization has not yet led to definitive knowledge of the mechanisms producing NMDRCs in human populations, there appear to be strong similarities in cells, animals, and humans that support a call for continued work focusing on metabolic disease endpoints at each level of biological organization.

D. NMDRC summary

We have demonstrated that nonmonotonicity is a common occurrence after exposures to hormones and EDCs in cell culture and animals and across human populations. Because of the abundance of examples of NMDRCs, we expect that if adequate dose ranges are included in animal and cell culture studies, including the use of negative and well-chosen positive controls, NMDRCs may be observed more often than not. Here, we have focused mainly on studies that examined a wide range of doses, including many that examined the effects of doses that span the low-dose and toxicological ranges. We also discussed several mechanisms that produce NMDRCs. Each of these mechanisms can and does operate at the same time in a biological system, and this cooperative action is ultimately responsible for NMDRCs.

Understanding nonmonotonicity has both theoretical and practical relevance. When a chemical produces monotonic responses, all doses are expected to produce similar effects whose magnitude varies with the dose, but when a chemical produces a NMDRC, dissimilar or even opposite effects will be observed at different doses. Thus, monotonic responses can be modeled using the assumption that each step in a linear pathway behaves according to the law of mass action (43, 570); high doses are always expected to produce higher responses. In contrast, NMDRCs are not easy to model (although they are quite easy to test for), requiring detailed knowledge of the specific mechanisms operating in several biological components. From a regulatory standpoint, information from high doses cannot always be used to assess whether low doses will produce a biological effect (38).

IV. Implications of Low-Dose Effects and Nonmonotonicity

Both low-dose effects and NMDRCs have been observed for a wide variety of EDCs as well as natural hormones. Importantly, these phenomena encompass every level of biological organization, from gene expression, hormone production, and cell number to changes in tissue architecture to behavior and population-based disease risks. One conclusion from this review is that low-dose effects and NMDRCs are often observed after administration of environmentally relevant doses of EDCs. For both hormones and EDCs, NMDRCs should be the default assumption absent sufficient data to indicate otherwise. Furthermore, there are well-understood mechanisms to explain how low-dose effects and NMDRCs manifest *in vitro* and *in vivo*. Accepting these phenomena, therefore, should lead to paradigm shifts in toxicological studies and will likely also have lasting effects on regulatory science. Some of these aspects are discussed below. Additionally, we have briefly explored how this knowledge should influence future approaches in human and environmental health.

At a very practical level, we recommend that researchers publishing data with low-dose and nonmonotonic effects include key words in the abstract/article that identify them as such specifically. This review was unquestionably impeded because this has not been standard practice. We also strongly recommend that data showing nonmonotonic and binary response patterns not be rejected or criticized because there is no dose response.

A. Experimental design

1. Dose ranges must be chosen carefully

To detect low-dose effects or NMDRCs, the doses included for testing are of utmost importance. Most of the studies we examined here for nonmonotonicity tested doses over severalfold concentrations. Unfortunately, regulatory guidelines only require that three doses be tested. Both low-dose effects and NMDRCs can be observed when examining only a few doses, but some studies may detect significant results purely by luck, because a small shift in dose can have a large impact on the ability to observe differences relative to untreated controls.

In the multitude of chemicals that have never been tested at low doses, or in the development of new chemicals, to determine whether a chemical has low-dose effects in laboratory animals, we suggest setting the NOAEL or LOAEL from traditional toxicological studies as the highest dose in experiments specifically designed to test endocrine-sensitive endpoints. We suggest setting the lowest dose in the experiment below the range of human exposures, if such a dose is known. Several intermediate doses overlapping the range of typical human exposures should be included also, bringing the total number in the range of five to eight total doses tested. Importantly, although the levels of many environmental chemicals in human blood and/or urine have been reported by the CDC and other groups responsible for population-scale biomonitoring, it is often not known what administered doses are needed to achieve these internal exposure levels in animals (4, 253); thus, toxicokinetic studies are often needed before the onset of low-dose testing. This is important because the critical issue is to determine what effects are observed in animals when circulating levels of an EDC match what is measured in the typical human. Due to differences in metabolism, route of exposure, and other factors, a relatively high dose may need to be administered to a rodent to produce blood concentrations in the range of human levels; however, this should not be considered a high-dose study.

It has also been suggested that animal studies that are used to understand the potential effects of a chemical on humans should use a relevant route of administration to recapitulate human exposures (571, 572) because there may be differences in metabolism after oral and nonoral administration. Many chemicals that enter the body orally undergo first-pass metabolism and are then inactivated via liver enzymes, whereas other routes (*i.e.* sc) can bypass these mechanisms and lead to a higher concentration of the active compound in circulation (573). Studies indicate, however, that inactivation of chemicals via first-pass metabolism is not complete and also that deconjugation of metabolites can occur in some tissues allowing the re-release of the active form (574, 575). Additionally, for some chemicals, it is clear that route of administration has little or no impact on the availability of the active compound in the body (241, 384), and other studies show that route of administration has no impact on the biological effects of these chemicals; *i.e.* regardless of how it enters the body, dioxin has similar effects on exposed individuals (384), and comparable results have been observed for BPA (141). Although understanding the typical route of human exposure to each environmental chemical is an important task, it has been argued that any method that leads to blood concentrations of a test chemical in the range they are observed in humans is an acceptable exposure protocol, and this is especially true with gestational exposures, because fetuses are exposed to chemicals only via their mothers' blood (31, 576).

2. Timing of exposures is important

Rodent studies indicate that EDC exposures during development have organizational effects, with permanent effects that can manifest even in late adulthood, whereas exposures after puberty are for the most part activational, with effects that are abrogated when exposures cease. For example, the adult uterus requires relatively large doses of BPA (in the parts-per-million range) to induce changes associated with the uterotrophic assay (555, 577), whereas parts-per-trillion and ppb exposures during the fetal period permanently and effectively alter development of the uterus (279, 310, 578). Thus, the timing of exposures is profoundly important to detect low-dose effects of EDCs.

Human studies also support this conclusion. The 1976 explosion of a chemical plant in Seveso, Italy, which led to widespread human exposure to large amounts of TCDD, a particularly toxic form of dioxin, and the deposition of this chemical on the land surrounding the chemical plant, provided evidence in support of the organizational and activational effects of endocrine-active chemicals in humans (579). Serum TCDD concentrations showed correlations between exposure levels and several disease outcomes including breast cancer risk, abnormal menstrual cycles, and endometriosis (580–582), but individuals who were either infants or teenagers at the time of the explosion were found to be at greatest risk for developing adult diseases (583, 584). Importantly, many scientists have argued that organizational effects can occur during puberty, *i.e.* that the period where hormones have irreversible effects on organ development extends beyond the fetal and neonatal period (585), and for some endpoints this appears to be the case (586, 587).

It has also been proposed that the endocrine system maintains homeostasis in the face of environmental insults (210). The adult endocrine system does appear to provide some ability to maintain a type of homeostasis; when the pharmaceutical estrogen DES is administered to pregnant mice, the circulating estradiol concentrations in the dam respond by decreasing linearly (224). In contrast, fetal concentrations of estradiol respond nonmonotonically in a way that is clearly not correlated with maternal levels. Similarly, there is evidence that BPA can induce aromatase and therefore increase estradiol levels *in situ* in the fetal urogenital sinus (588). This is an example of a feed-forward positive-feedback effect rather than a homeostatic response. The effects of EDCs on adult subjects, both animal and people, suggest that diseases often result from low-dose adult exposures (589–595); this argues against a view of the endocrine system as a means to maintain homeostatic control. Instead, individuals can be permanently changed, in an adverse way, after EDC exposures.

In one example, pregnant mice were exposed to low concentrations of BPA, and their male offspring had altered pancreatic function at 6 months of age (158). Surprisingly, however, the mothers (exposed only during pregnancy) were also affected, with altered metabolic machinery and body weight at 4 months postpartum, long after exposures had ended. The increased incidence of breast cancer in women that took DES during pregnancy also illustrates this point (596, 597). These studies suggest that even the adult endocrine system is not invariably capable of maintaining a so-called homeostatic state when exogenous chemicals affecting the endocrine system are present. Thus, although adult exposures to EDCs have been given some attention by bench scientists (29), more work of this kind is needed to better understand whether and how EDCs can have permanent organizational effects on adult animals.

At the beginning of this review, we justified the need to critically examine the low-dose literature because of recent epidemiological findings linking EDC exposures and diseases. Yet there is inherent difficulty in examining neonatal exposures to EDCs and their connection to diseases due to the length of time needed for these studies; thus, many studies of this type have examined high doses of pharmaceuticals (*i.e.* DES) or accidental exposures to industrial chemicals (*i.e.* dioxin) (66, 398, 399, 581, 597–601).

Only recently, with the availability of biomonitoring samples from large reference populations, have lower doses begun to receive widespread attention from epidemiologists. Many recent studies have examined adult exposures to EDCs and correlated exposures with disease statuses (see for example Refs. 15, 16, and 602–604). Human studies examining fetal/neonatal exposures to low-dose EDCs and early life effects have also begun to be studied (6, 333, 605–607), although studies linking these early life exposures to adult diseases are likely to be decades away. More than anything, these studies support our view that the effects of low-dose exposures should be considered when determining chemical safety.

3. Importance of endpoints being examined

Traditional toxicology testing, and in particular those studies performed for the purposes of risk assessment, typically adhere to guideline studies that have been approved by international committees of experts (608). The endpoints assessed in these guideline-compliant studies are centered around higher-order levels, including death, weight loss, mortality, and changes in organ weight, and a limited number of histopathological analyses (609, 610). When pregnant animals are included in toxicological assessments, the endpoints measured typically include the ability to maintain pregnancies, the number of offspring delivered, sex ratios of surviving pups, and measures regarding maternal weight gain and food/water intake (610).

Yet low-dose EDCs are rarely toxic to the point of killing adult animals or causing spontaneous abortions, and traditional tests such as the uterotrophic assay have been shown to be relatively insensitive (72, 577). It has been argued that this type of testing is insufficient for understanding the effects of EDCs (31, 70, 495, 611). Many EDC studies have instead focused on examining newly developed, highly sensitive endpoints that span multiple levels of biological organization, from gene expression to tissue organization to organ systems to the whole animal (612), which may not be rapidly lethal but which nonetheless have enormous importance for health, including mortality. Thus, for example, studies designed to examine the effects of chemicals on obesity no longer focus on body weight alone but also analyze gene expression; fat content in adipose cells and the process of adipogenesis; inflammation, innervation, and vascularization parameters in specific fat pads; conversion rates of white and brown adipose tissues; systemic hormone levels and response to glucose and insulin challenges; and food intake and energy expenditures, among others (314, 613–615). As our knowledge of EDCs and the endocrine system continue to grow, the most sensitive endpoints should be used to determine whether a chemical is disrupting the development of organisms (70).

In moving beyond traditional, well-characterized health-related endpoints like mortality and weight loss, an important question has been raised: how do we define endpoints as adverse? This is an important point, because it has been suggested that the creative endpoints examined in independent EDC studies are not validated and may not represent adverse effects (609). There is also debate over whether the mechanism (or mode) of action must be explained for each effect to determine whether a relevant pathway is present in humans (616, 617). Yet, when originally assessing the low-dose literature, the NTP expert panel chose to examine all effects of EDC exposure, regardless of whether the endpoint could be deemed adverse (2). From the perspective of developmental biology, any change in development should be seen as adverse, even if the change itself is not associated with a disease or dysfunction. Some of these developmental changes, in fact, may increase sensitivity or susceptibility to disease later on in life but will otherwise appear normal. Furthermore, studies of heavy metals have shown that small shifts in parameters like IQ may not have drastic effects on individuals but can have serious repercussions on the population level (618), and therefore changes in the variance/observable range of a phenotype should also be considered adverse (52).

4. Importance of study size

National Institutes of Health guidelines require that the number of vertebrate animals used in experiments be as small as possible to show statistically significant effects based on power analysis. Yet many traditional toxicology studies have used large numbers of animals to draw conclusions about chemical safety. When the endpoints being assessed have binary outcomes (*i.e.* animal has a tumor *vs.* animal does not have a tumor) and the incidence of the phenotype is not high, a large number of animals is required to reveal statistically significant effects. In contrast, many of the endpoints examined in the field of endocrine disruption are more complex and are not binary; thus, power analysis allows researchers to determine how many animals are needed to observe statistically significant (and biologically relevant) differences between control and exposed populations. For this reason, arbitrary numbers set as cutoffs for determining whether a study is acceptable or unacceptable for risk assessments are not appropriate. Instead, the number of animals required for a study to be complete is dependent on the effect size, precision/variance, minimal meaningful difference to be considered between populations, and the α-value set in statistical tests.

B. Regulatory science

For decades, regulatory agencies have tested, or approved testing, of chemicals by examining high doses and then extrapolating down from the NOAEL, NOEL, and LOAEL to determine safe levels for humans and/or wildlife. As discussed earlier, these extrapolations use safety factors that acknowledge differences between humans and animals, exposures of vulnerable populations, interspecies variability, and other uncertainty factors. These safety factors are informed guesses, not quantitatively based calculations. Using this traditional way of setting safe doses, the levels declared safe are never in fact tested. Doses in the range of human exposures are therefore also unlikely to be tested. This has generated the current state of science, where many chemicals of concern have never been examined at environmentally relevant low doses (see Table 4 for a small number of examples).

Assumptions used in chemical risk assessments to estimate a threshold dose below which daily exposure to a chemical is estimated to be safe are false for EDCs. First, experimental data provide evidence for the lack of a threshold for EDCs (619). More broadly, the data in this review demonstrate that the central assumption underlying the use of high doses to predict low-dose effects will lead to false estimates of safety. The use of only a few high doses is based on the assumption that all dose-response relationships are monotonic and therefore that it is appropriate to apply a log-linear extrapolation from high-dose testing to estimate a safe reference dose (Fig. 4). The Endocrine Society issued a position statement on EDCs (620) and urged the risk assessment community to use the expertise of their members to develop new approaches to chemical risk assessments for EDCs based on principles of endocrinology. Undertaking this mission will represent a true paradigm shift in regulatory toxicology (79). The Endocrine Society statement was then supported in March 2011 by a letter to *Science* from eight societies with relevant expertise representing over 40,000 scientists and medical professionals (621).

Studies conducted for the purposes of risk assessment are expected to include three doses: a dose that has no effects on traditional toxicological endpoints (the NOAEL), a higher dose with effects on traditional endpoints (the LOAEL), and an even higher dose that shows toxicity. Although reducing the number of animals used for these types of studies is an important goal, more than three doses are often needed for a true picture of a chemical's toxicity. The examination of a larger number of doses would allow for 1) the study of chemicals at the reference dose, *i.e.* the dose that is calculated to be safe; 2) examination of doses in the range of actual human exposures, which is likely to be below the reference dose; and 3) the ability to detect NMDRCs, particularly in the low-dose range. The impact of testing more doses on the numbers of animals required can be mitigated by use of power analysis, as suggested above. Because no amount of research will ever match the diversity and reality of actual human experience, there should be ongoing epidemiological study of potential adverse effects of EDCs even after safe levels are published, with periodic reevaluation of those safe levels.

One issue that has been raised by regulatory agencies is whether animal models are appropriate for understanding the effects of EDCs on humans. These arguments largely center around observed differences in hormone levels during different physiological periods in rodents and humans (57), and differences in the metabolic machinery and excretion of chemicals between species (622). To address the first issue, it should be noted that the FDA uses animals to test pharmaceuticals and other chemicals before any safety testing in humans because it is widely recognized that, although animals and humans do not have exactly the same physiologies, there is evolutionary conservation among vertebrates and specifically among mammals (62). Furthermore, animal studies proved to be highly predictive of the effects of DES on women, indicating that rodents are sufficiently similar to humans to reliably forecast affected endpoints in the endocrine system (64, 623). Thus, the default position must be that animal data are indicative of human effects until proven otherwise.

With regard to the second issue, BPA researchers in particular have examined species-specific differences in metabolism of this EDC. Interestingly, the pharmacokinetics of BPA in rodents, monkeys, and humans appear to be very similar (624), and regulatory agencies have subsequently concluded that rodents are appropriate models to assess the effects of this chemical (625, 626). Thus, researchers should select animal models that are sensitive to low doses of hormones and select appropriate species for the endpoints of interest. As the scope of our knowledge has broadened about how chemicals can alter the endocrine system, well beyond estrogens, androgens, and the thyroid, it is imperative that considerable thought be given to how to apply this for regulatory purposes.

C. Human health

As discussed several times throughout this review, there is now substantial evidence that low doses of EDCs have adverse effects on human health. Thus, although many epidemiological studies originally focused on occupationally exposed individuals and individuals affected by accidental exposures to high doses of environmental chemicals, these recent studies have suggested wide-ranging effects of EDCs on the general population.

Importantly, human exposures are examples of true mixtures; dozens if not hundreds of environmental chemicals are regularly detected in human tissues and fluids (91), yet very little is known about how these chemicals act in combination (627). Several studies indicate that EDCs can have additive or even synergistic effects (143, 323, 628–630), and thus these mixtures are likely to have unexpected and unpredictable effects on animals and humans. The study of mixtures is a growing and complex field that will require considerable attention in the years ahead as knowledge of EDCs in the laboratory setting are applied to human populations (631, 632).

How much will human health improve by testing chemicals at low, environmentally relevant doses and using the results to guide safety determinations? Current testing paradigms are missing important, sensitive endpoints; because they are often unable to detect NMDRCs, they cannot make appropriate predictions about what effects are occurring at low doses. At this time, it is not possible to quantify the total costs of low-dose exposures to EDCs. However, current epidemiology studies linking low-dose EDC exposures to a myriad of health problems, diseases, and disorders suggest that the costs of current low-dose exposures are likely to be substantial.

The weight of the available evidence suggests that EDCs affect a wide range of human health endpoints that manifest at different stages of life, from neonatal and infant periods to the aging adult. As the American population ages, healthcare costs continue to rise, and there are societal costs as well, with decreased quality of life concerns, decreases in work productivity due to illness or the need for workers to care for affected family members, and the psychological stresses of dealing with some outcomes like infertility. Thus, it is logical to conclude that low-dose testing, followed by regulatory action to minimize or eliminate human exposures to EDCs, could significantly benefit human health. This proposal effectively calls for greatly expanded research to give human communities feedback about themselves. It emanates from a view that human society benefits greatly from the many chemical compounds it uses but that extensive epidemiological surveillance and other focused research designs are needed to assure that the balance of risk/benefit from those chemicals is acceptable.

How much would human health benefit by a reduction in the use of EDCs? For some chemicals, minor changes in consumer habits or industrial practices can have drastic effects on exposures (633–636). Other chemicals like DDT that have been regulated in the United States for decades continue to be detected in human and environmental samples; the persistent nature of many of these agents suggests they may impact human health for decades to come. Even less-persistent chemicals like BPA are likely to remain in our environment long after a ban is enacted because of the large amounts of plastic waste leaching BPA (and other estrogenic compounds) from landfills into water sources (637) and its presence on thermal receipt paper and from there into recycled paper (638–640). Yet, despite these challenges, reducing human exposure to EDCs should be a priority, and one way to address that priority is to decrease the production and use of these chemicals. The Endocrine Society has called for such a reduction and the use of the precautionary principle, *i.e.* action in the presence of concerning information but in the absence of certainty to eliminate or cut the use of questionable chemicals even when cause-effect relationships are not yet established (620).

D. Wildlife

Much of the recent focus on EDCs has been on the impact of these chemicals on human health. Yet the earliest studies of EDCs that focused on the impact of these chemicals on wildlife should not be forgotten. Rachel Carson's work on DDT and other pesticides provided some of the earliest warning signs that there were unintended consequences of chemical use. Carson's work was ahead of its time; she understood that exceedingly small doses of these chemicals produced adverse effects, that the timing of exposures was critical, and that chemical mixtures produced compounded effects (641). Now, decades after some of the most dangerous EDCs have been regulated, they continue to be measured in environmental samples as well as the bodies of wildlife animals.

Furthermore, it should be pointed out that humans, like wildlife, are not insulated from the environment, and effects in wildlife, including nonmammalian species, are indicative of and mirror effects in humans. For example, BPA has estrogen-like effects in fish (642–644), amphibians (645, 646), and reptiles (647, 648). A recent review showed that demasculinizing and feminizing effects of atrazine have been demonstrated in fish, amphibians, reptiles, birds, and mammals, *i.e.* every vertebrate class examined (326); and in fact, the first report to suggest that atrazine induced aromatase was conducted in reptiles (649). Similarly, perchlorate affects fish (650–653), amphibians (654–658), and birds (659–661) via mechanisms consistent with those described for humans, and some of the earliest reports on perchlorate's effects on thyroid function were conducted in amphibians (661, 662). Finally, ecological studies of dioxin and dioxin-like chemicals reveal effects on a range of exposed wildlife including birds (663, 664), fish (665, 666), and invertebrates (667). Although these studies have highlighted some of the species-specific effects of dioxin (389), and orders of magnitude differences in toxic equivalency factors between species (668), they also indicate the conservation of mechanisms for the effects of dioxin on a range of biological endpoints in wildlife, laboratory animals, and humans (384). In fact, in many cases, nonmammalian species are much more sensitive to EDC effects, and wildlife species serve as sentinels for environmental and public health (669–673). Thus, the effects of these chemicals on wildlife populations are likely to continue; for this reason, the low-dose effects of these chemicals are particularly worth understanding (674, 675).

V. Summary

In conclusion, we have provided hundreds of examples that clearly show that NMDRCs and low-dose effects are common in studies of hormones and EDCs. We have examined each of these issues separately and provided mechanistic explanations and examples of both. These topics are related, but they must be examined individually to be understood. The concept of nonmonotonicity is an essential one for the field of environmental health science because when NMDRCs occur, the effects of low doses cannot be predicted by the effects observed at high doses. In addition, the finding that chemicals have adverse effects on animals and humans in the range of environmental exposures clearly indicates that low doses cannot be ignored.

In closing, we encourage scientists and journal editors to publish data demonstrating NMDRCs and low-dose effects, even if the exact mechanism of action has not yet been elucidated. This is important because the study of EDC is a growing specialty that crosses many scientific fields, and scientists that work on or regulate EDCs should appreciate and acknowledge the existence of NMDRCs and low-dose effects and have access to this important information. We further recommend greatly expanded and generalized safety testing and surveillance to detect potential adverse effects of this broad class of chemicals. Before new chemicals are developed, a wider range of doses, extending into the low-dose range, should be fully tested. And finally, we envision that the concepts and empirical results we have presented in this paper will lead to many more collaborations among research scientists in academic and government laboratories across the globe, that more and more sophisticated study designs will emerge, that what we have produced herein will facilitate those making regulatory decisions, that actions taken in light of this information will begin to abate the use of EDCs, and ultimately that health impacts in people and in wildlife will be averted.

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We dedicate this manuscript to Professor Howard A. Bern. Dr. Bern was an exceptionally brilliant biologist and a generous and inspiring colleague. His work spanning a wide range of organisms addressed multiple aspects of organismal and evolutionary biology. He was one of the founders of the field of comparative endocrinology and a pioneer in the study of endocrine disruption, anticipating the deleterious effects of developmental exposure to estrogens one decade before the discovery of the effects of diethylstilbestrol in women fetally exposed to this chemical. His pioneering work included, among other subjects, neuroendocrinology, reproduction, and mammary cancer. He was also an excellent mentor to many researchers who, in turn, advanced these endeavors. He left an indelible mark on all of us that had the privilege of meeting him.

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Air

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

HYDROGEN SULFIDE REPORT TO CONGRESS -- EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Findings and Recommendations

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

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

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CHAPTER I
INTRODUCTION

STATUTORY REQUIREMENTS

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

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

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

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

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

SCOPE OF REPORT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ORGANIZATION OF REPORT

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

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

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

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

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

OVERVIEW

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

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

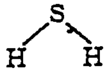
H_2S is generated under reducing conditions from high-sulfur kerogens or oils and is most commonly formed in sedimentary rock formations such as limestone (calcite or calcium carbonate). H_2S can also be generated from hydrocarbon reactions with sulfates in carbonate rock formations containing anhydrites.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

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

Table II-1. Physical/Chemical Properties of H_2S

Chemical Formula: H_2S

Molecular Structure:



Molecular Weight: 34.08

Boiling Point: -60.33 °C (-76.59 °F)

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

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

Melting Point: -85.49 °C (-121.9 °F)

Vapor Density (AIR=1): 1.19

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

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

Odor Threshold: 20 ppb[a]

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

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

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

Source: U.S. EPA, 1993.
[a] NIOSH, 1977.

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

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

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

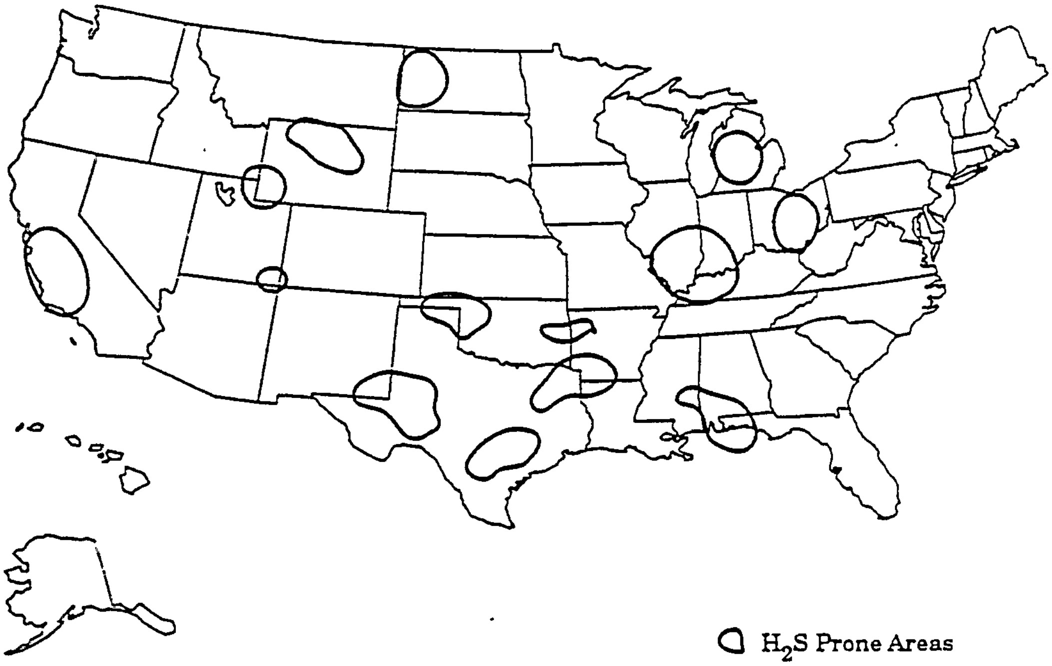
HYDROGEN SULFIDE IN INDUSTRY

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

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

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

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



Source: Gas Research Institute. 1990.

Figure II-1. Major H_2S prone areas.

Table II-2. Occupations with Potential H_2S Exposure

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

Source: NIOSH. 1977.

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

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

Routine emission sources may include—

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

Potential accidental release sources include —

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

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

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

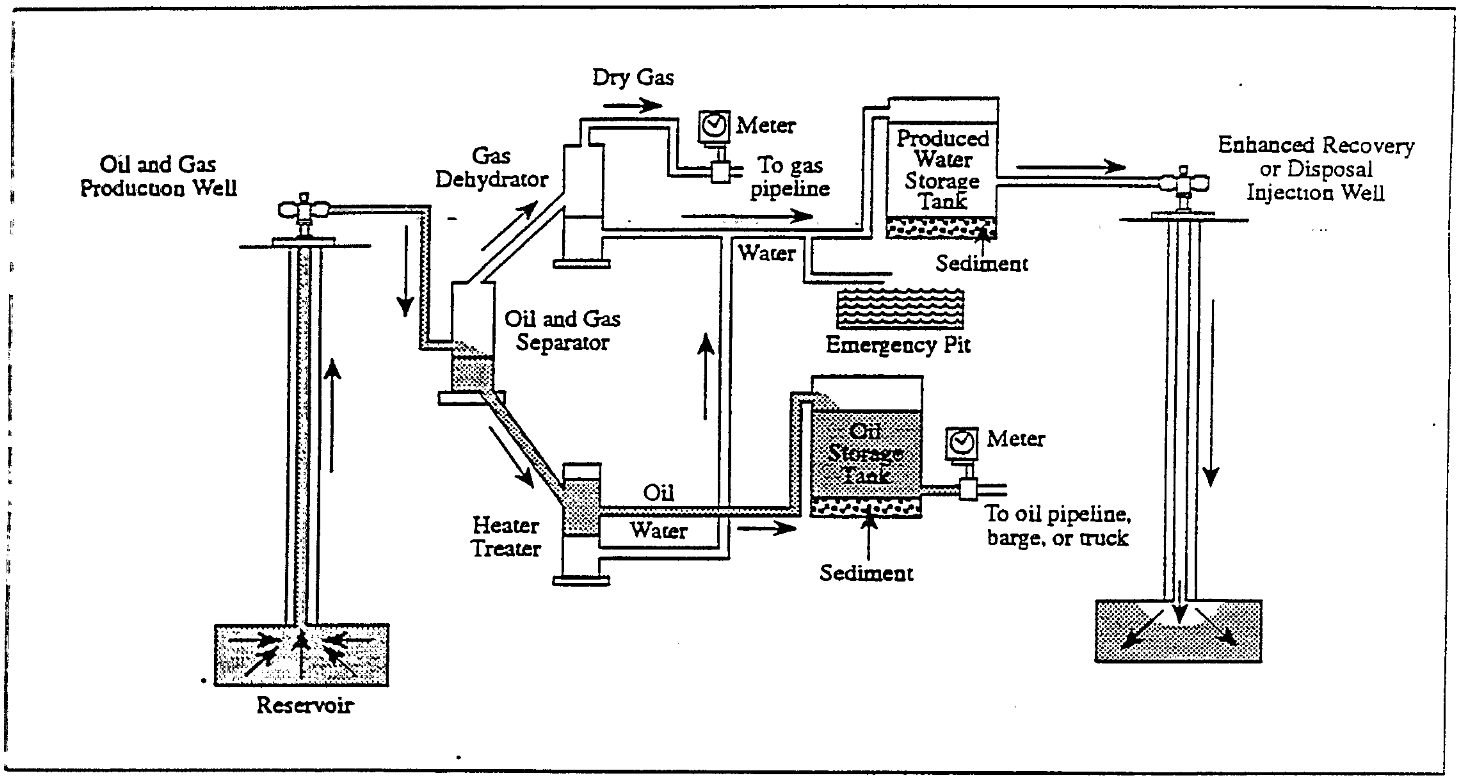
Oil and Gas Production Operations

Crude Oil

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

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

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



Source: U.S. EPA, 1987.

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

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

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

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

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

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

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

Natural Gas

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

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

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

Stripper Wells

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

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CHAPTER III
HAZARD ASSESSMENT OF OIL AND GAS WELLS

INTRODUCTION

Objective

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

Focus of Assessment

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

Scope and Limitations

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

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

Hazard Assessment Steps

This hazard assessment was divided into three major parts:

- Hazard Identification
- Exposure Analysis
- Consequence Analysis

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

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

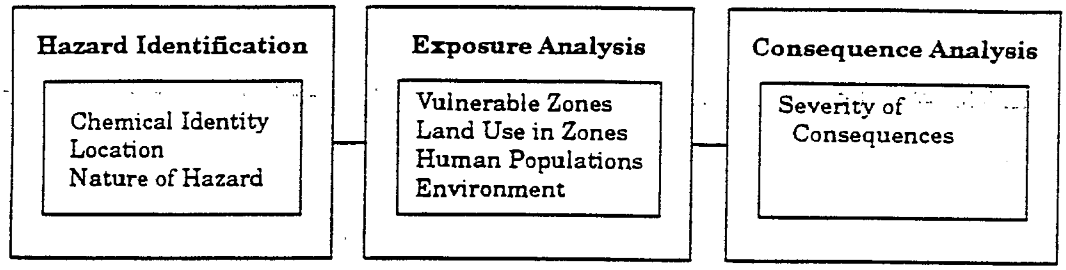
The second step, exposure analysis, included identification of the H_2S prone areas for H_2S exposure in the United States and the human and ecological populations expected to be in these zones. The final part of the assessment, consequence analysis, was an examination of H_2S routine emissions and accidental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

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

HAZARD IDENTIFICATION

Chemical Identity

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



Adapted from: U.S. EPA, 1987.

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

Location

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

Nature of Hazard

Exposure Routes, Absorption, Metabolism, and Elimination

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

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

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

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

Acute Human Toxicity

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

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

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

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

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

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

Source: U.S. EPA, 1993.

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

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

Chronic Human Toxicity

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

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

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

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

Ecological Effects

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

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

Flammability, Explosivity, and Corrosivity

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

Table III-2. Effects of Ecological Exposure to H_2S

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

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

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

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

ACGIH Threshold Limits

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

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

LC_{01}

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

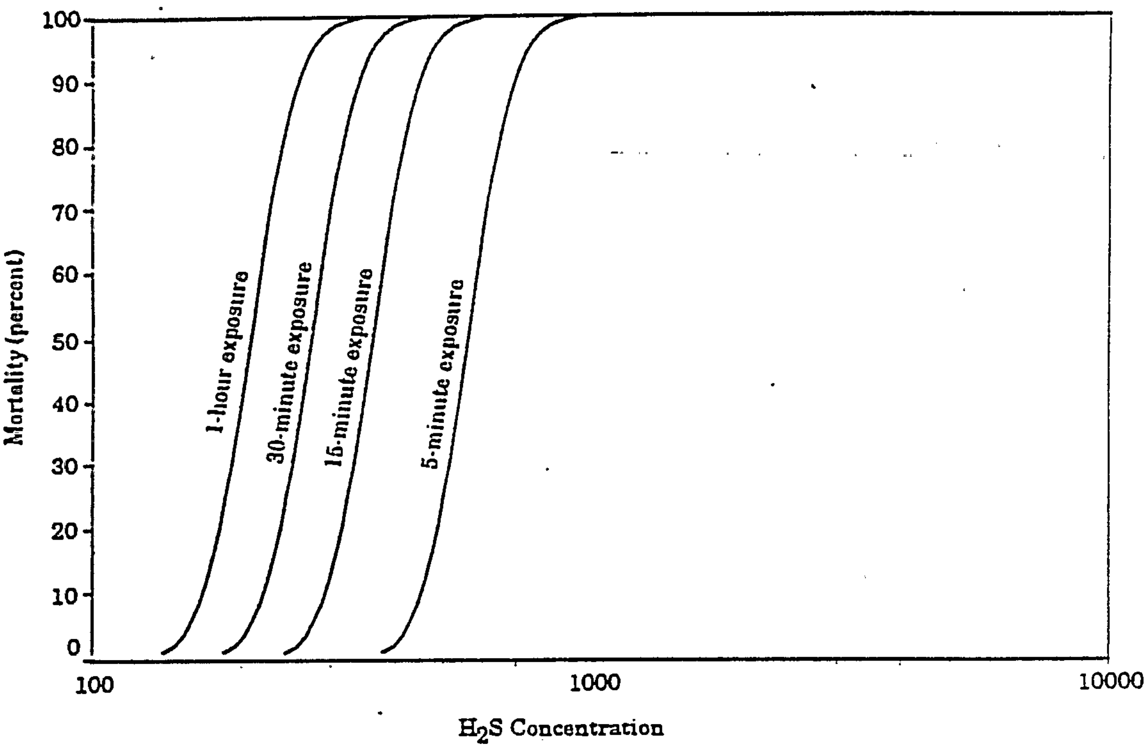
For H_2S, the Center for Chemical Process Safety of the American Institute of Chemical Engineers (AIChE) has a probit equation which gives k = 83,500 and n = 1.43, with C in ppb and t in minutes (AIChE, 1989). Thus, for a five minute exposure, $LC_{01} = 8.95 \times 10^5$ ppb and, for a one hour exposure,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

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

AIHA Guidelines

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

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



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

Figure III-2. ERCB H_2S probit relations.

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

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

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

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

NAS/NRC Guidelines

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

EXPOSURE AND CONSEQUENCE ANALYSES

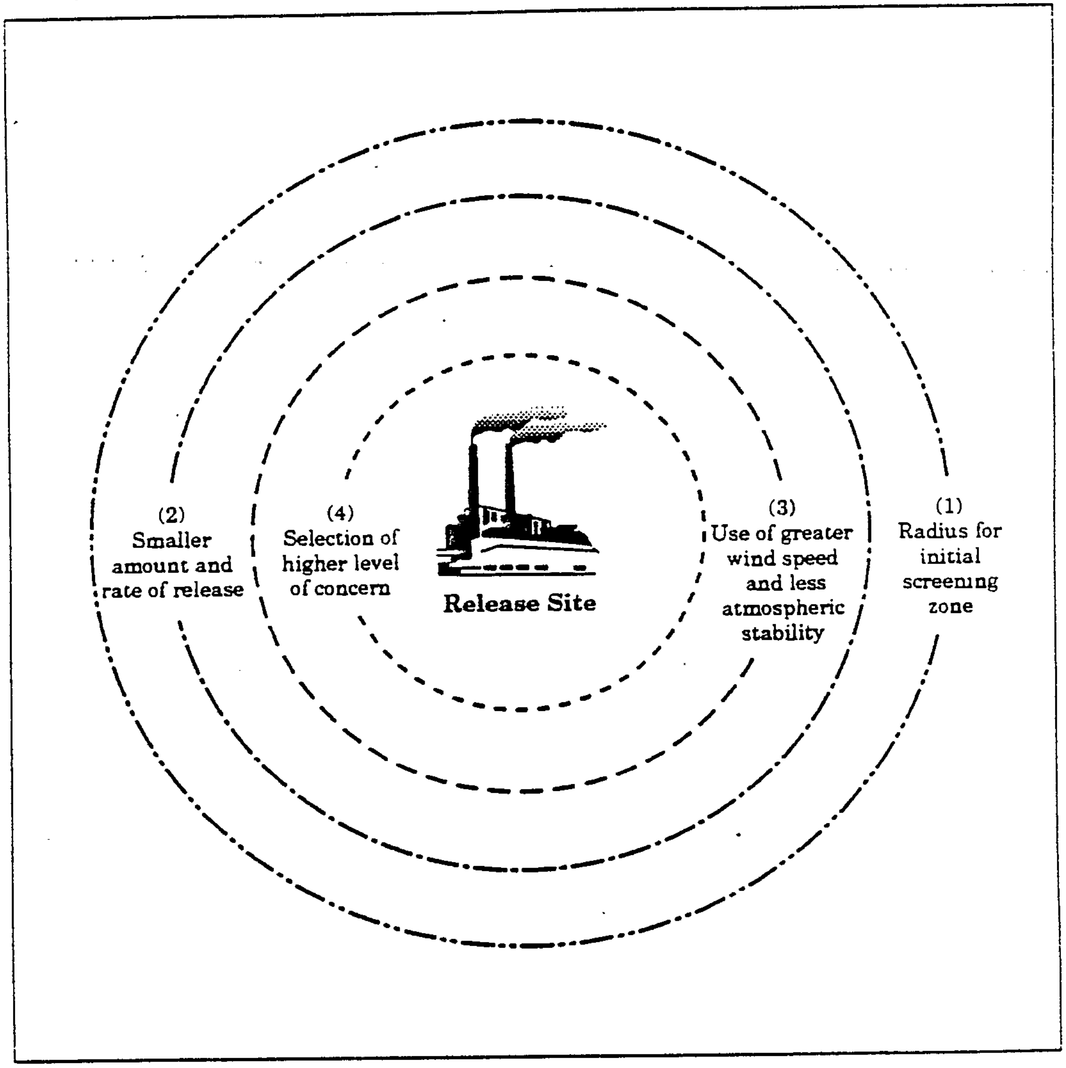
In this section, potential exposures to and consequences of exposure to H_2S from oil and gas wells are analyzed. The zones of the United States most likely to contain H_2S are identified and the potentially exposed human and ecological populations are discussed. Routine emissions and accidental releases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

Vulnerability Zones

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

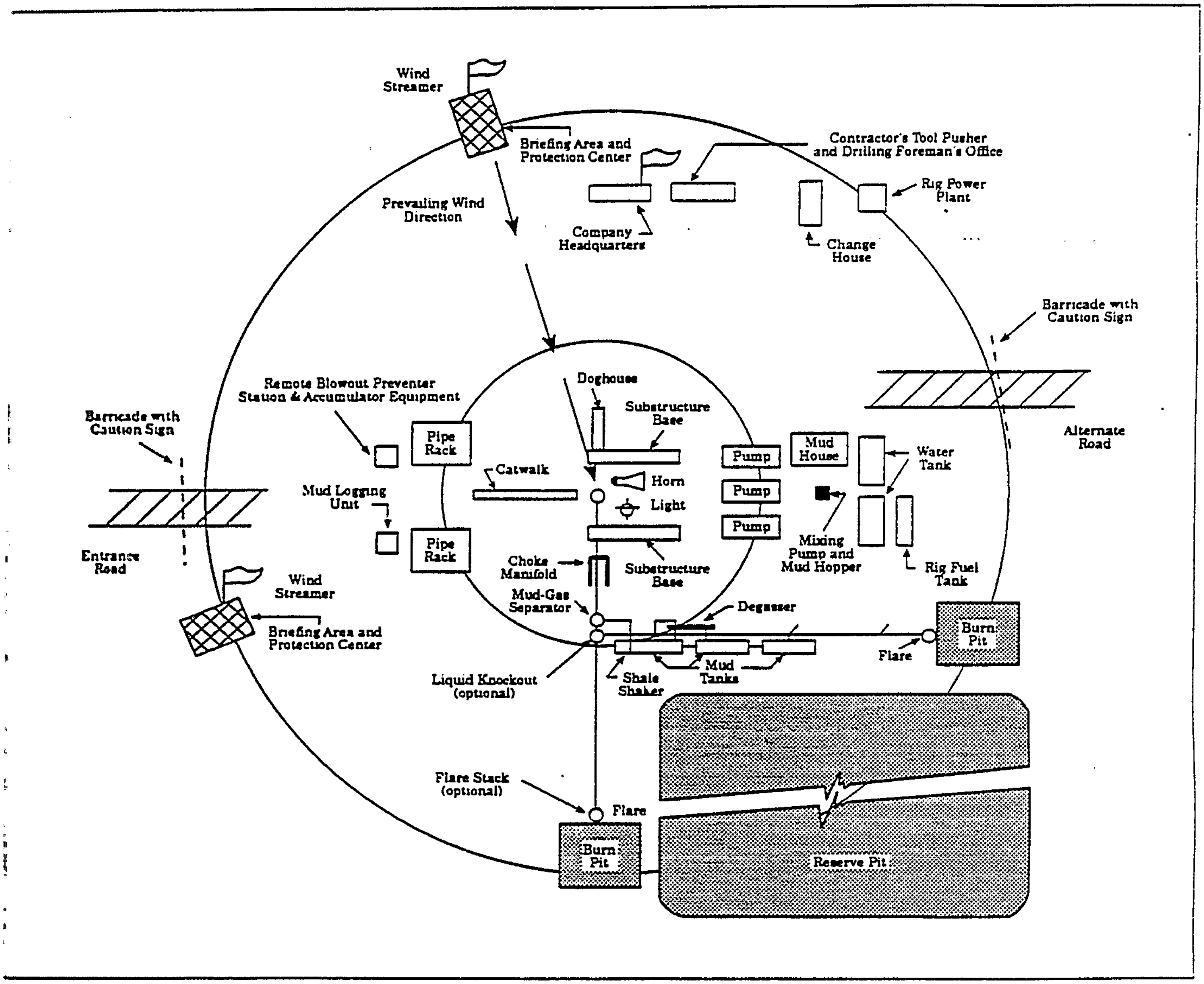
Estimated vulnerability zones are shown in Figure III-3 as circles with different radii to illustrate how changing conditions or assumptions can influence the vulnerablity zone estimate. With most atmospheric releases, the actual concentration of the airborne chemical tends to decrease as it moves further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

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



Source: U.S. EPA. 1987.

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



Source: API, 1987.

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

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

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

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

Exposure Analysis — Routine Emissions

Monitoring Records

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

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

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

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

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

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

Table III-3. North Dakota H_2S Monitoring Studies

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

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

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

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

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

violation occurs the second time the standard is exceeded.

Monitor out of service much of the time period.

Exceedance defined as 2 times the standard.

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

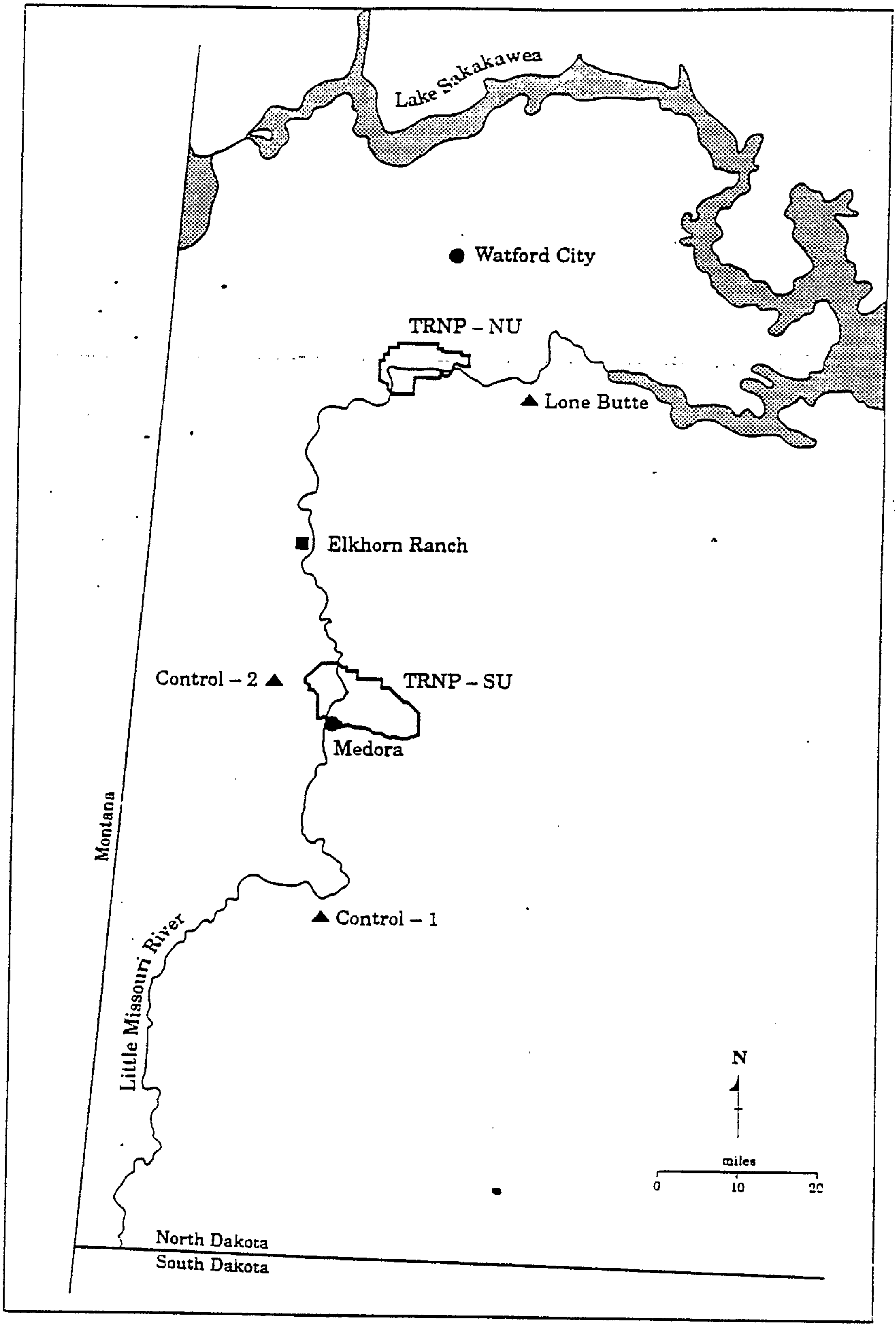
- 1 x 10^4 ppb or 14 mg/m^3) maximum instantaneous concentration not to be exceeded;
- 200 ppb or 280 $\mu g/m^3$) maximum 1-hour average concentration not to be exceeded more than once per month;
- 100 ppb or 140 $\mu g/m^3$) maximum 24-hour average concentration not to be exceeded more than once per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

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

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

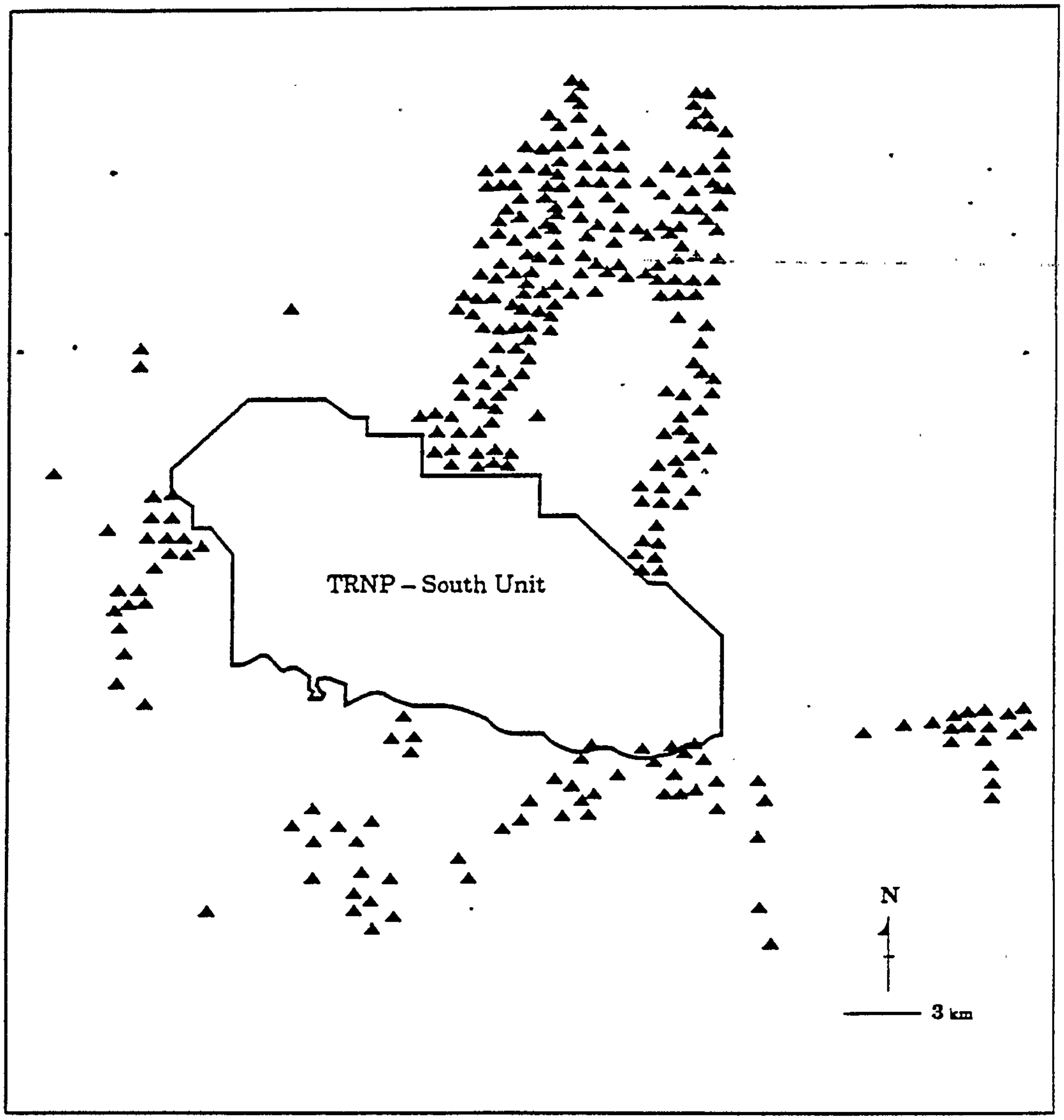
At the Lostwood Wildlife Refuge, data were obtained for the period from December 26, 1985, until January 14, 1991. Throughout the time period the maximum average concentration was 88 ppb, recorded as a 1-hour average in 1990. Overall, this was a site with acceptable air quality with respect to hydrogen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

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



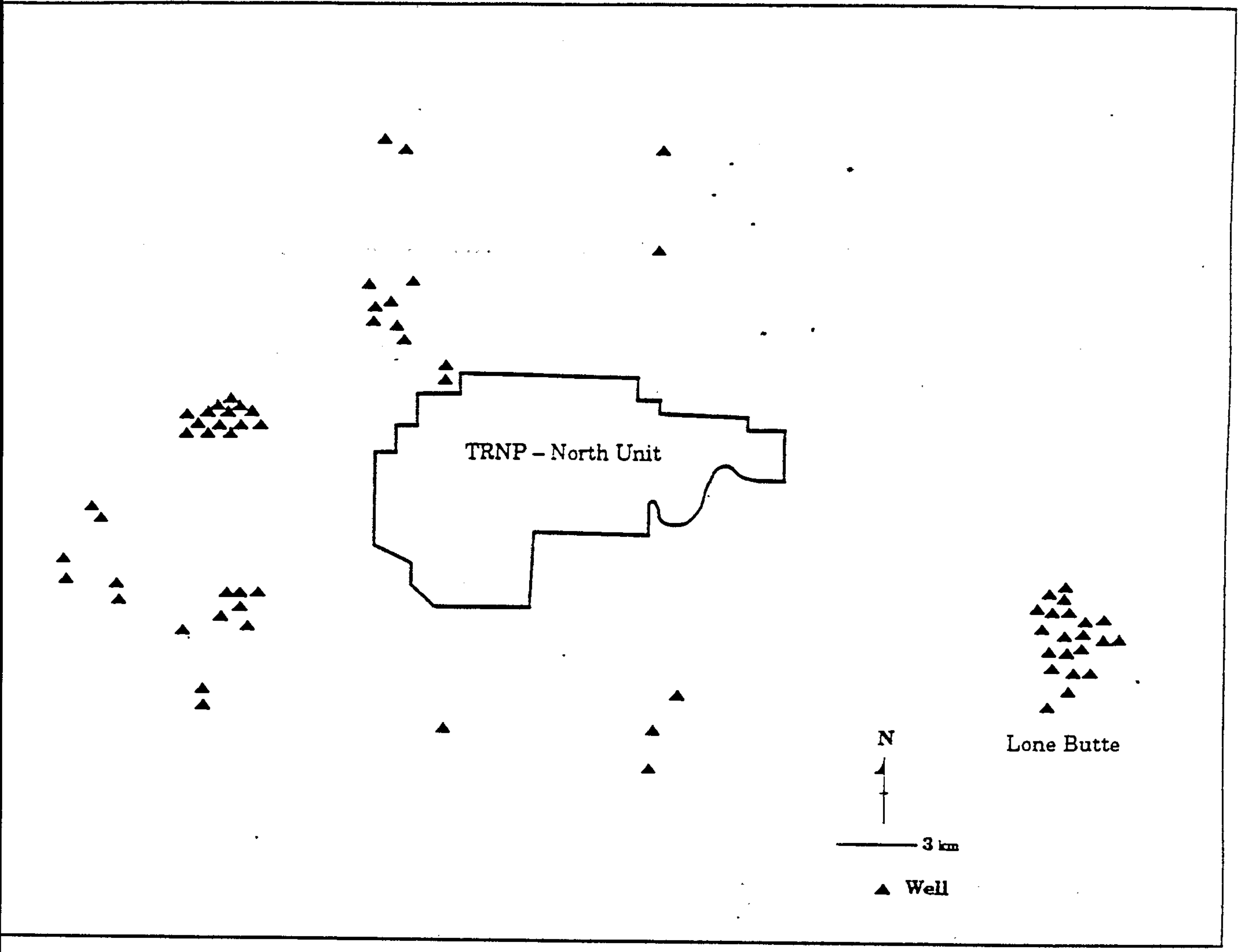
Source: Bilderbeck, 1988.

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



Source: Bilderbeck, 1988.

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



urce: Bilderbeck, 1988.

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

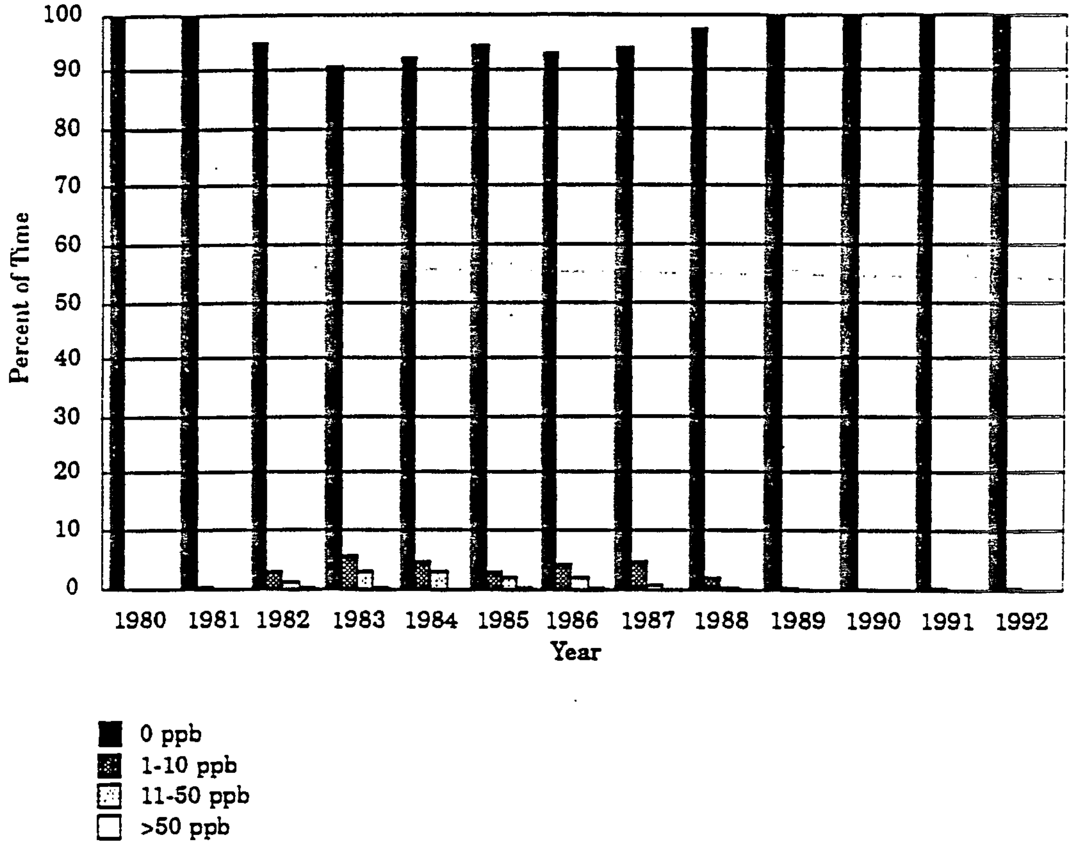
concentration of 18 ppb. The longest period of monitoring data received was from the north unit (recorded in the Little Missouri River Valley), covering the period from April 24, 1980, to August 2, 1992 (1990 data were not received by NDSDH&CL). In the early years, numerous violations of the 1/2-hour,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

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

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

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

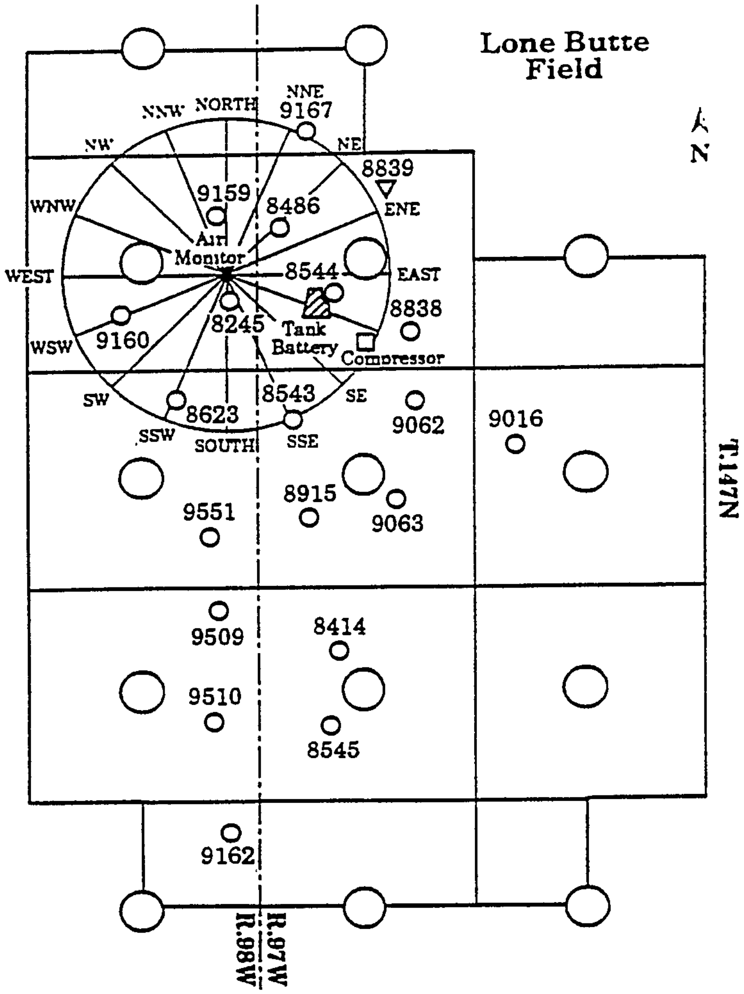
Other Monitoring Sites. Data from thirteen months of monitoring during 1989-1990 were recorded at the Olson farmyard, 1.5 miles from several wells in North Dakota. A maximum 1-hour average concentration of 88 ppb was recorded. Data were also obtained from September 4, 1990, to August 3, 1992, from a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



H_2S monitor detection limit = 1ppb

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

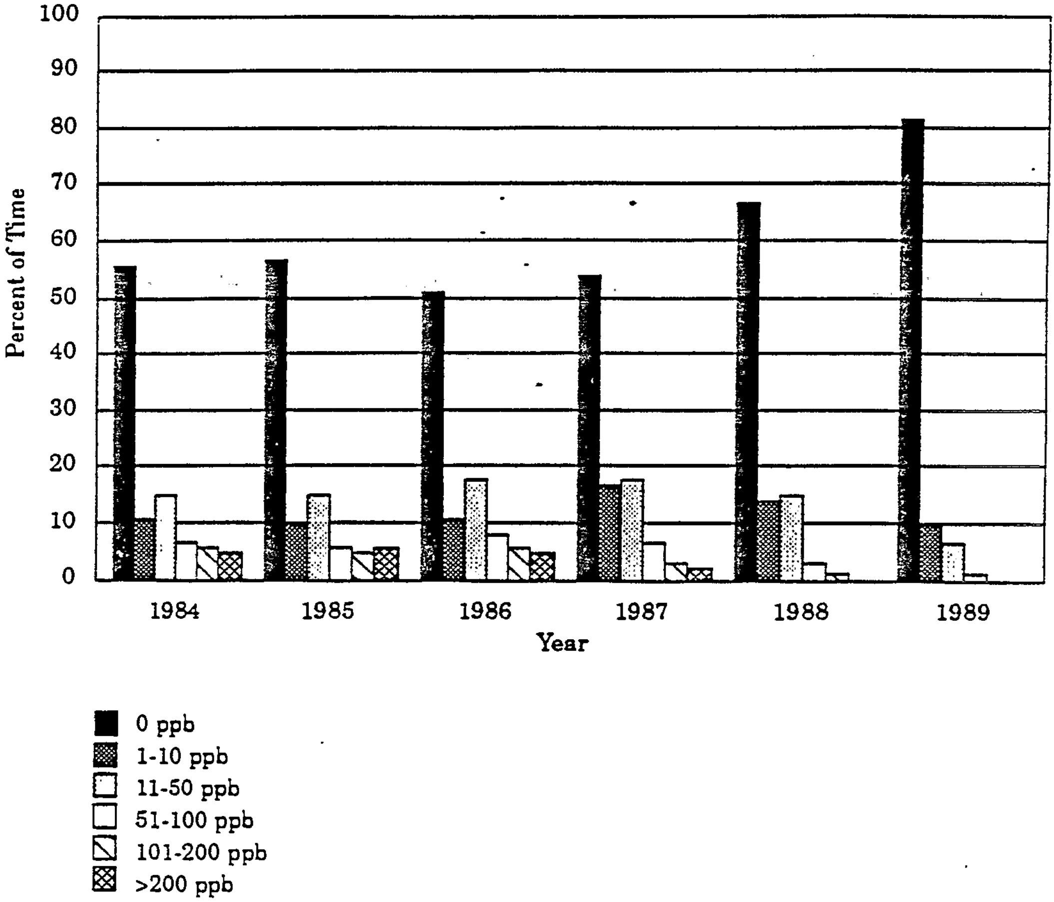
Figure III-8. Percentage of times designated H_2S concentrations were measured at the Theodore Roosevelt National Park - North Unit monitoring site.



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

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

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



H_2S monitor detection limit = 1ppb

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

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

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

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

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

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

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

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

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

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

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

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

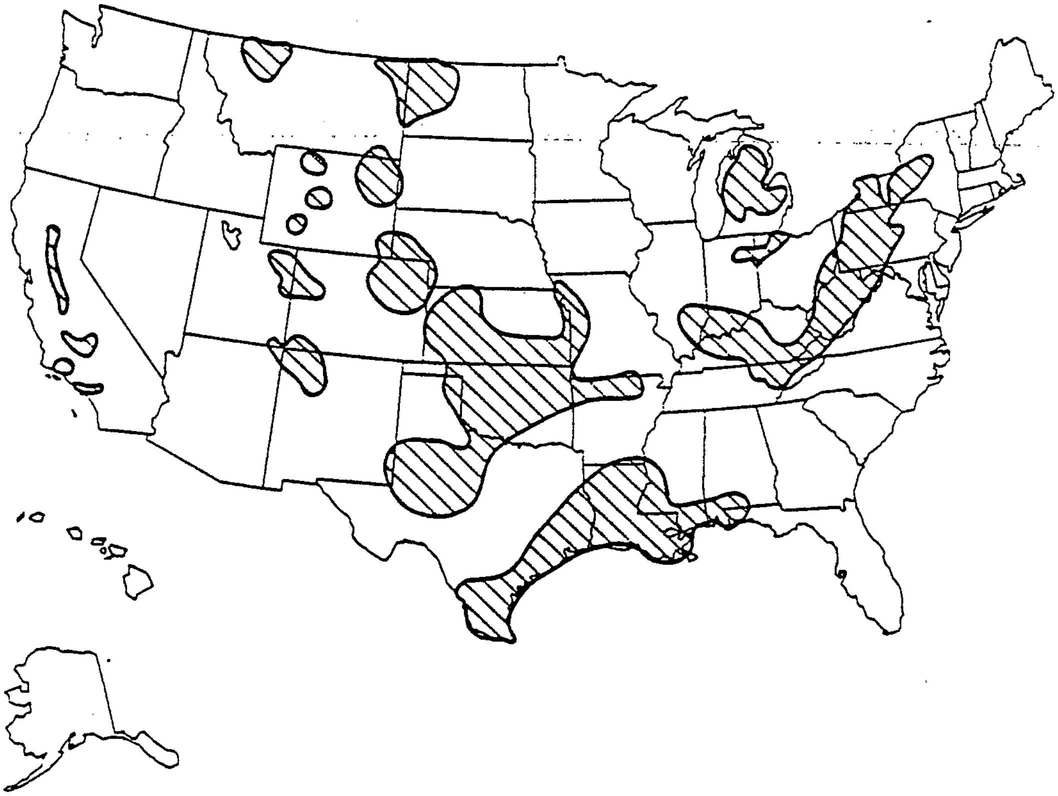
At low concentrations, odor nuisance and eye and respiratory tract irritation are the consequences of exposure rather than the toxic properties of the gas. An explanation for an increased perception of ill health could be related to low level exposure to hydrogen sulfide and pulmonary infections. A study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

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

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

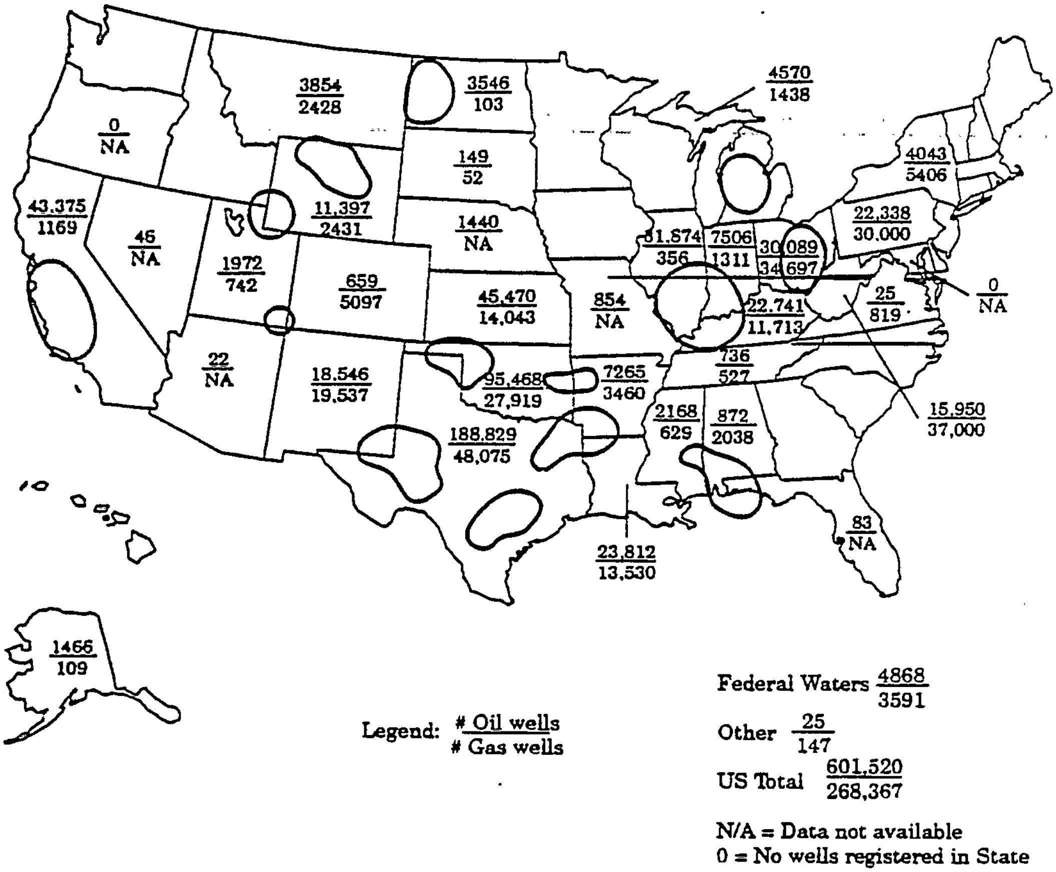
Consequence Analysis — Routine Emissions

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



Source: IOGCC, 1990.

Figure III-11. Oil and gas fields.



Source: Gas Research Institute, 1990.

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

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

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

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

Exposure Analysis—Accidental Releases

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

Accidental Release Records

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

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

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

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

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

Atmospheric Dispersion Analysis

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

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

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

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

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

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

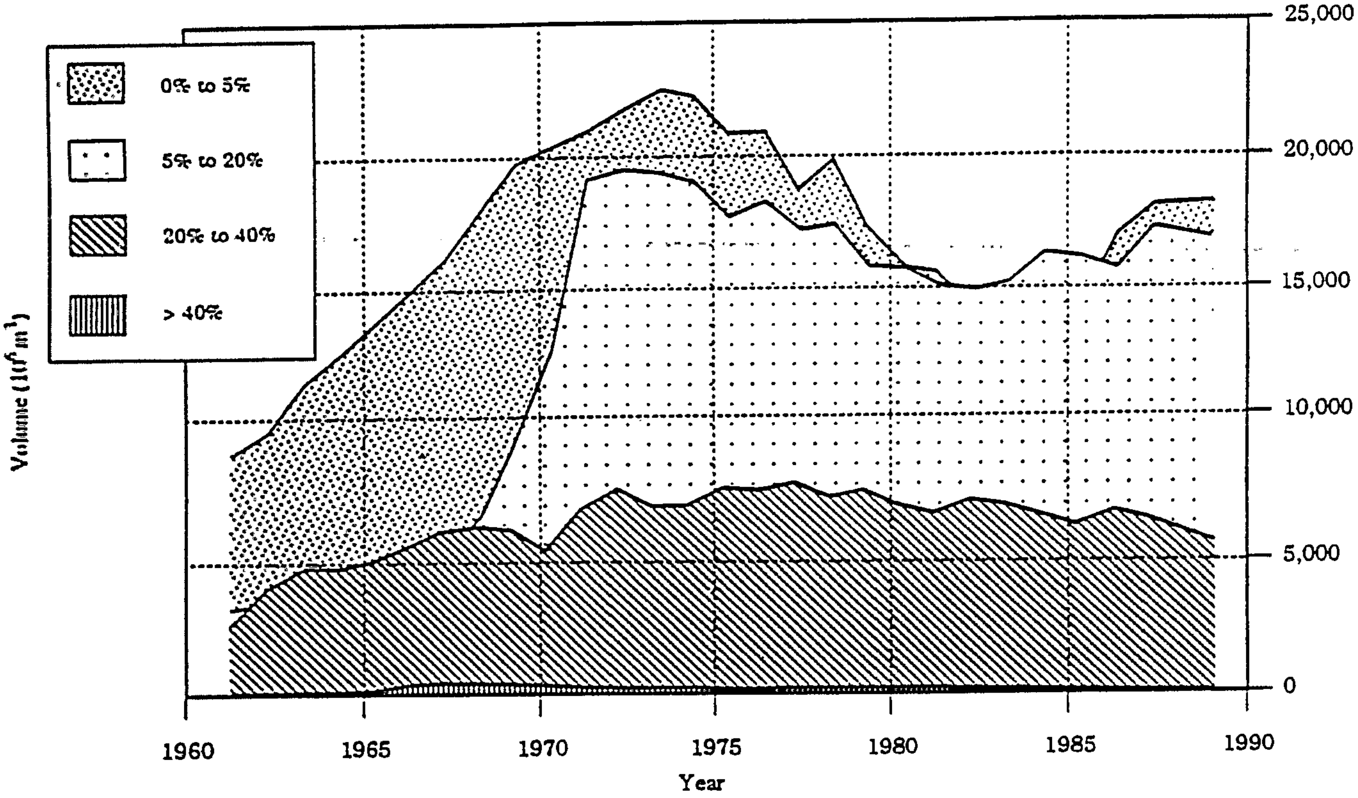
There is a wide variety of potential compositions of sour gas mixtures, depending on the reservoir. The density of these mixtures depends on their composition. In addition to hydrogen sulfide, natural gas can also contain some or all of the following: hydrogen, helium, carbon dioxide, nitrogen, methane,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

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

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

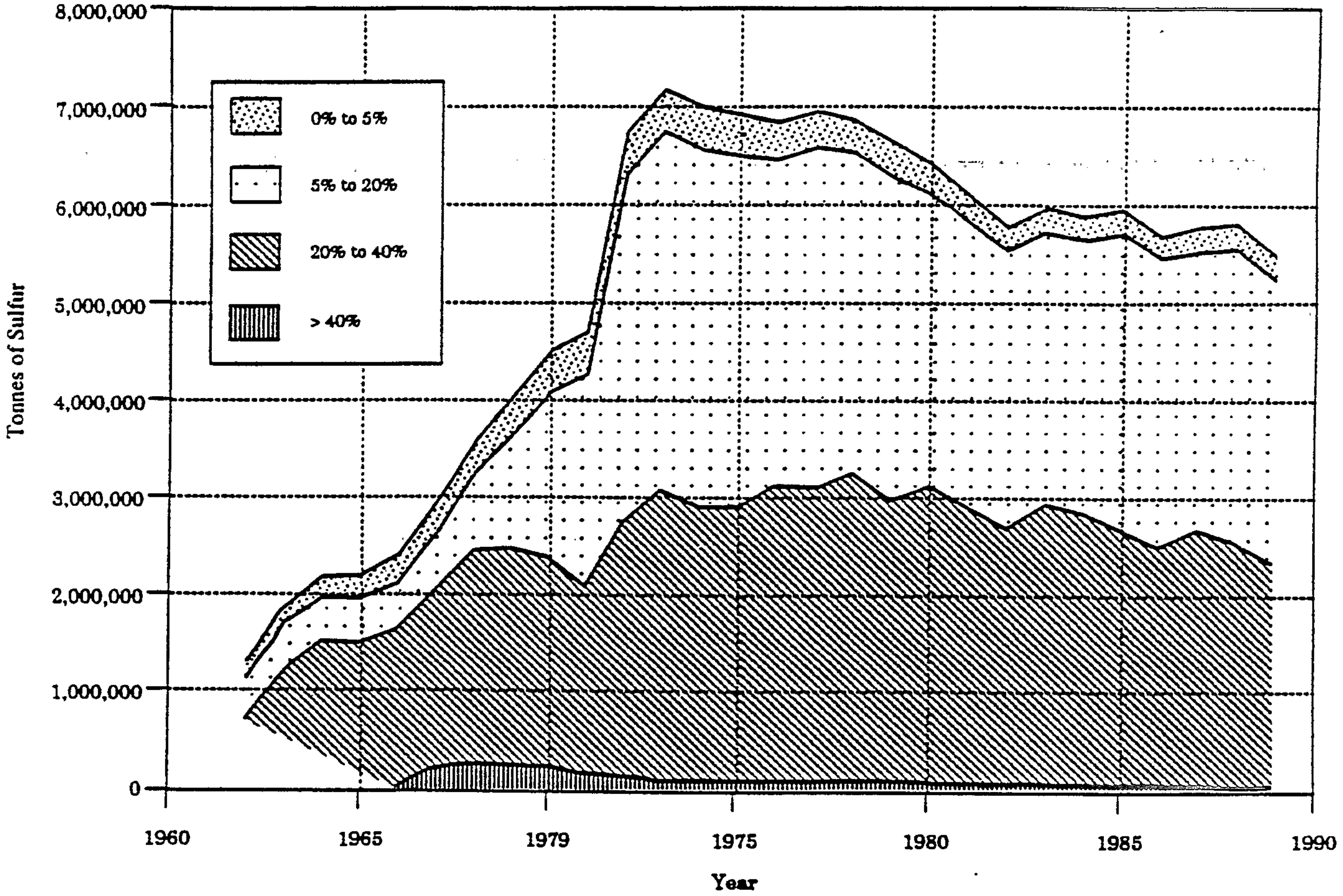
Some example sour gas compositions are presented in Table III-5.. Composition D is the single composition considered representative of all the data on producing gas wells in Alberta, Canada. Composition C is a representative gas composition produced by wells in a southwestern Wyoming sour gas field (Quest,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

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



Source: Alp et al., 1990.

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



Source: Alp et al., 1990.

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

ble III-5. Example Gas Stream Compositions

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

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

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

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

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

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

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

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

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

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

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

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

Consequence Analysis — Accidental Releases

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

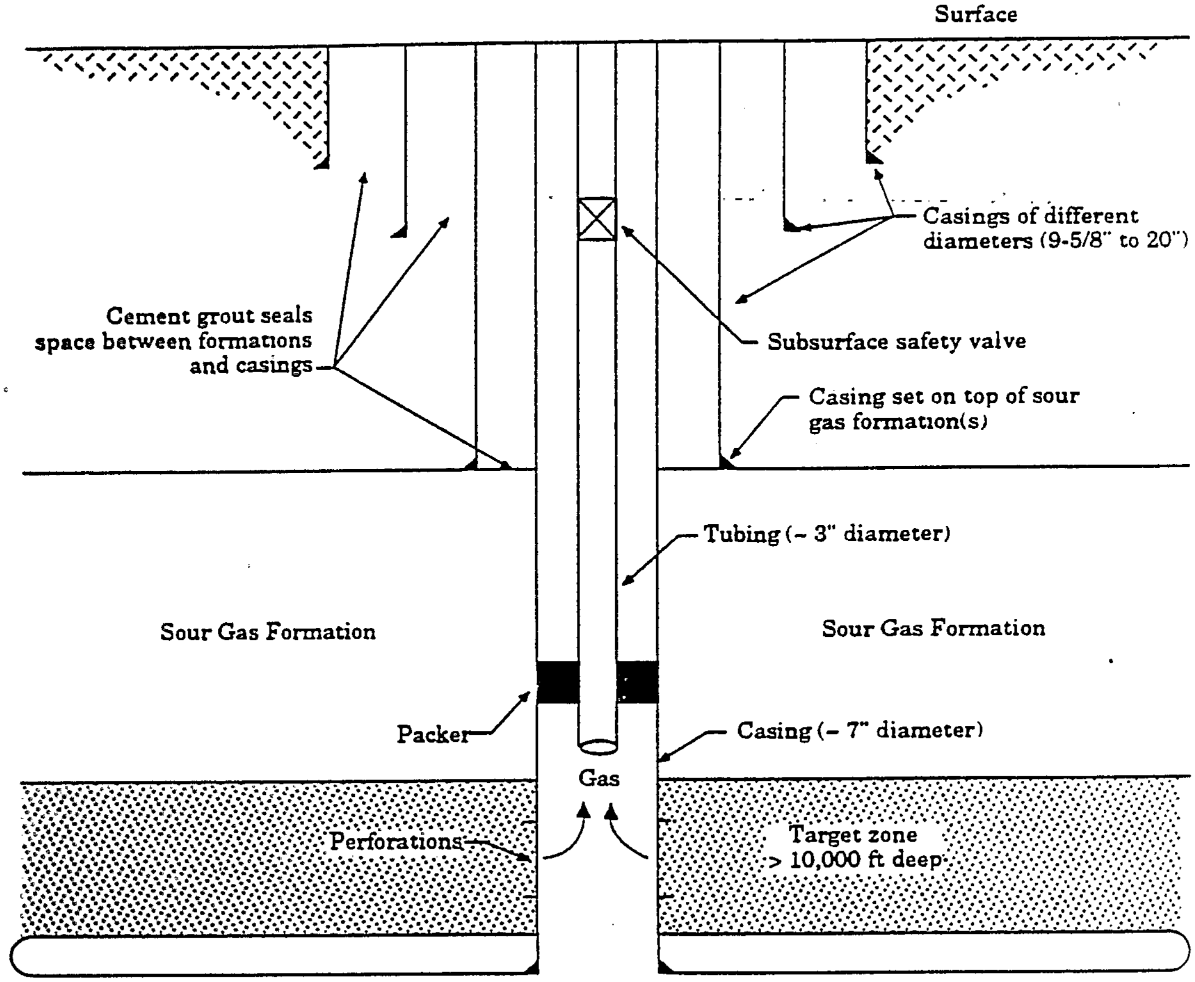
It should be noted that the calculated consequences of some of the modeled scenarios are based on very conservative assumptions in order to examine the worst case. The worst-case scenario is designed to generate the maximum impact off-site. It is considered to be extremely unlikely and does not take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

Consequence Analysis of Jets from Well Blowouts

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

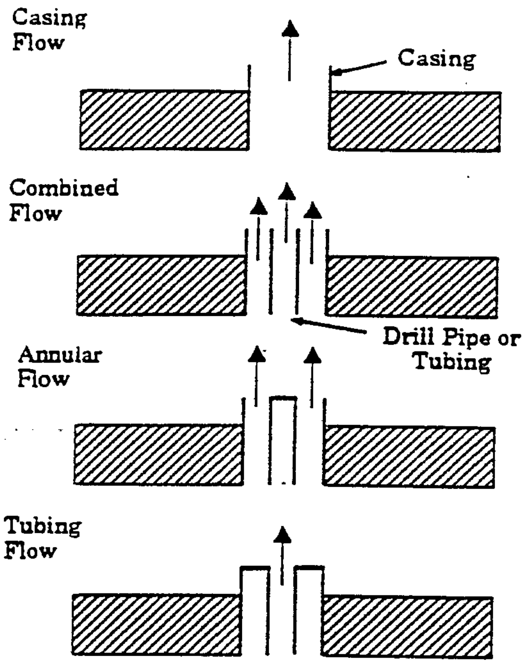
Flow rates for the scenarios identified in Figure III-16 are functions of such items as rock permeabilities, gas properties, depth, and tubing and casing diameters. Overall, there are large variabilities in these parameters. One measure of the potential rate of flow from a well is the Calculated Absolute Open Flow Rate (CAOF), which is the rate of flow of gas into the well bore when the pressure is atmospheric. This measure represents a maximum possible flow rate. The actual flow rates out of a ruptured well will be less than the CAOF because of frictional effects in the pipework. Thus, the use of CAOF for a release rate is conservative. Table III-6 gives some representative examples of how the CAOF is reduced for a specific set of well parameters. A flow rate of $2x10^7$ standard cubic feet per day (scf/d) was chosen for representative calculations, with a flow rate of 10^8 scf/d being taken as an example of a very high flow rate. The bases for these assumptions are presented in Appendix C.

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



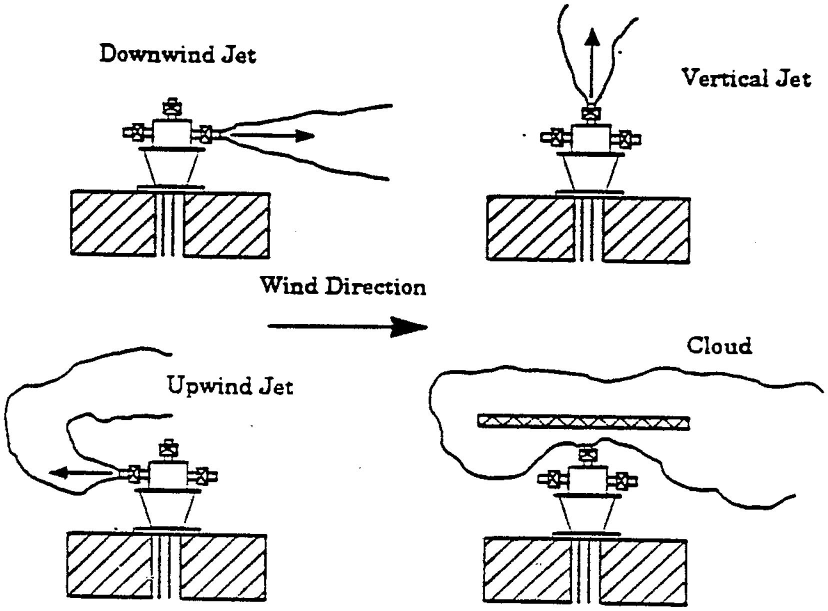
Source: Layton et al., 1983.

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



Source: Alp et al., 1990.

Figure III-16. Possible well flow scenarios.



Source: Alp et al., 1990.

Figure III-17. Possible well accidental release geometries.

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

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

Source: Alp et al., 1990.

* At 15°C and 101.3kPa.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

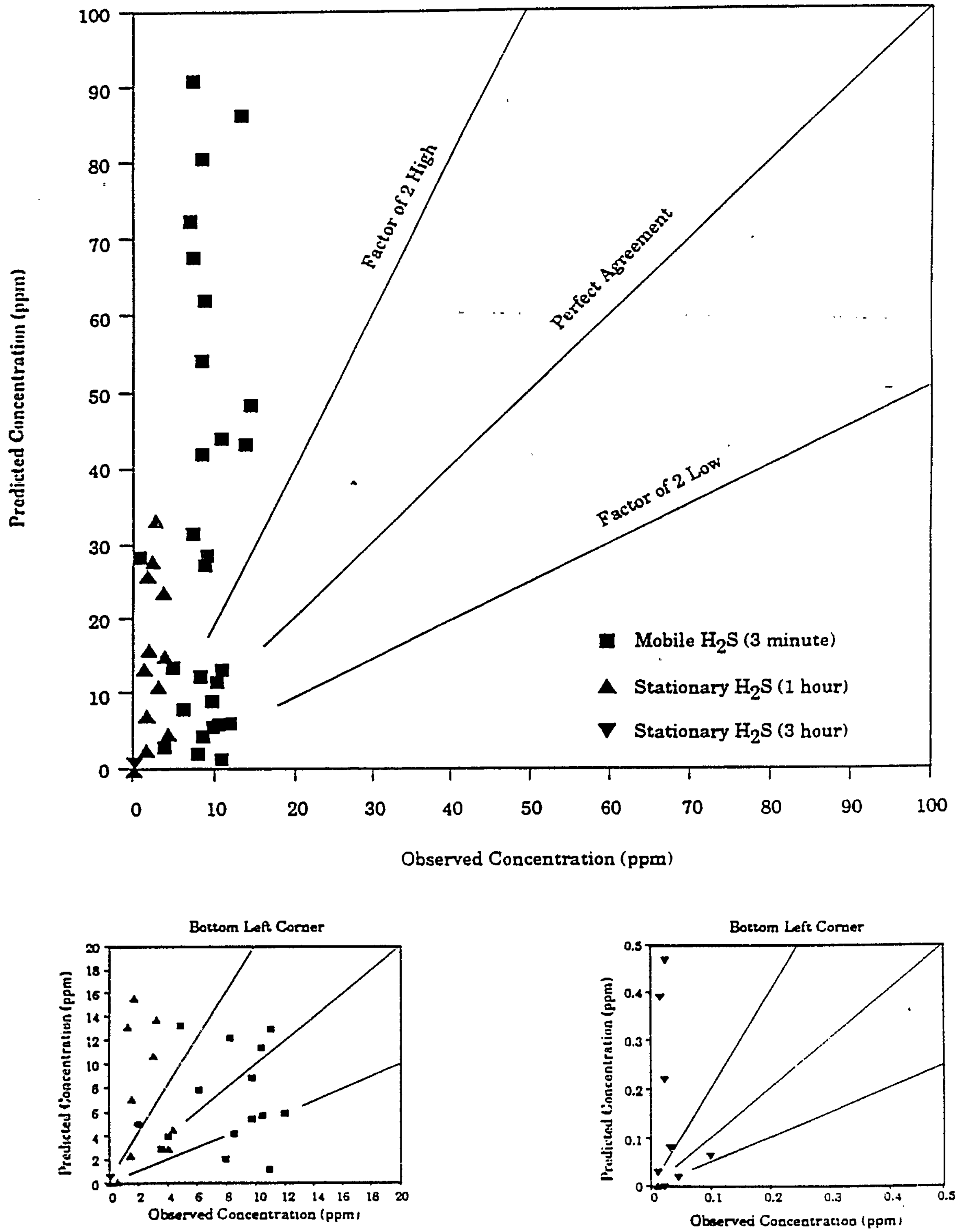


Figure III-18. Predicted H_2S and SO_2 concentrations for selected well blowout observations.

Consequence Analysis of Line Ruptures

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

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

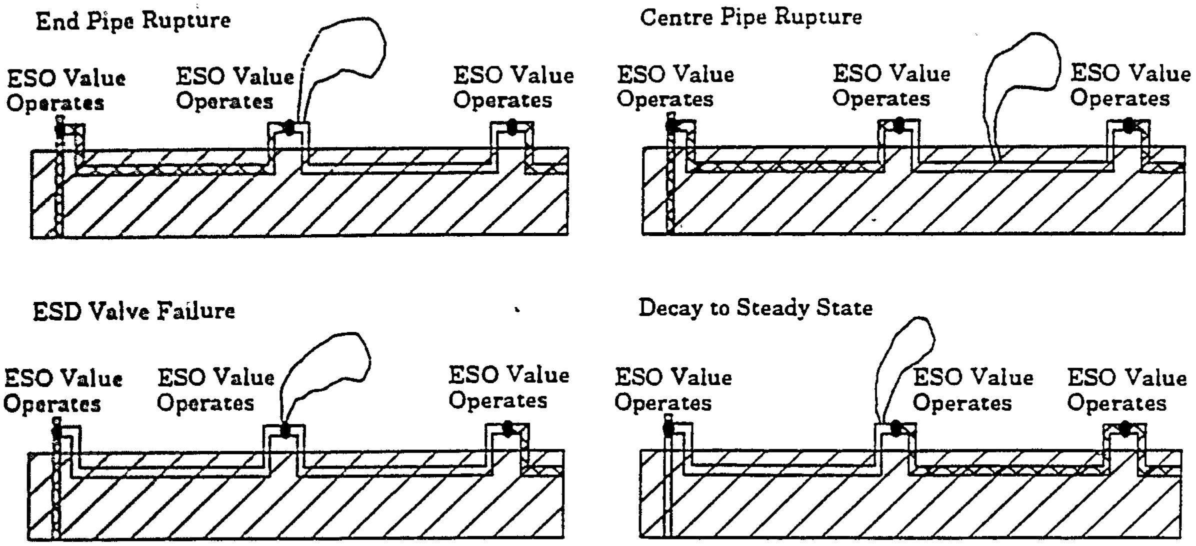
Figure III-22 shows mass release rates as a function of time for various pipe diameters and various ESD separations with an assumed line pressure of approximately 50 atmospheres (735 psi). The variable, t_d, listed on Figure III-22 is the time in seconds taken for 99 percent of the line contents to be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

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

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

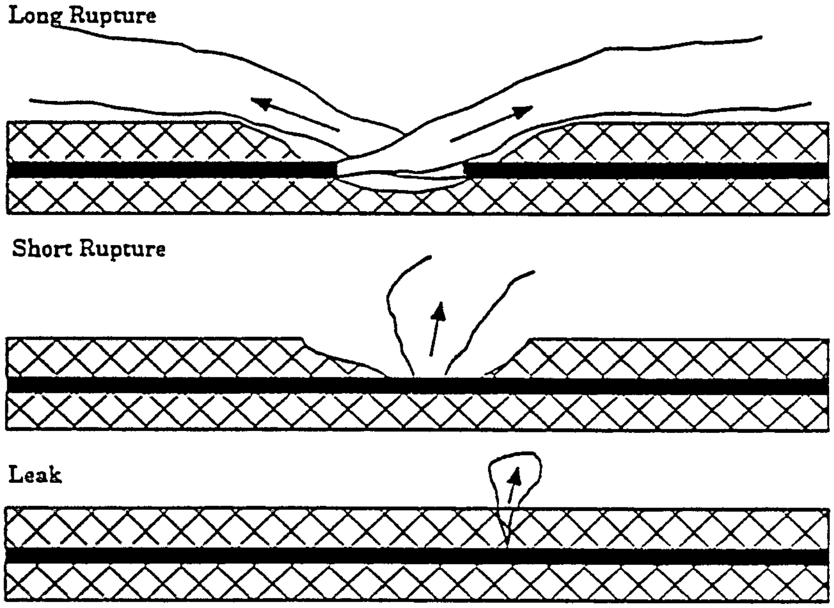
Consequence Analysis of Line Release Seepage

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



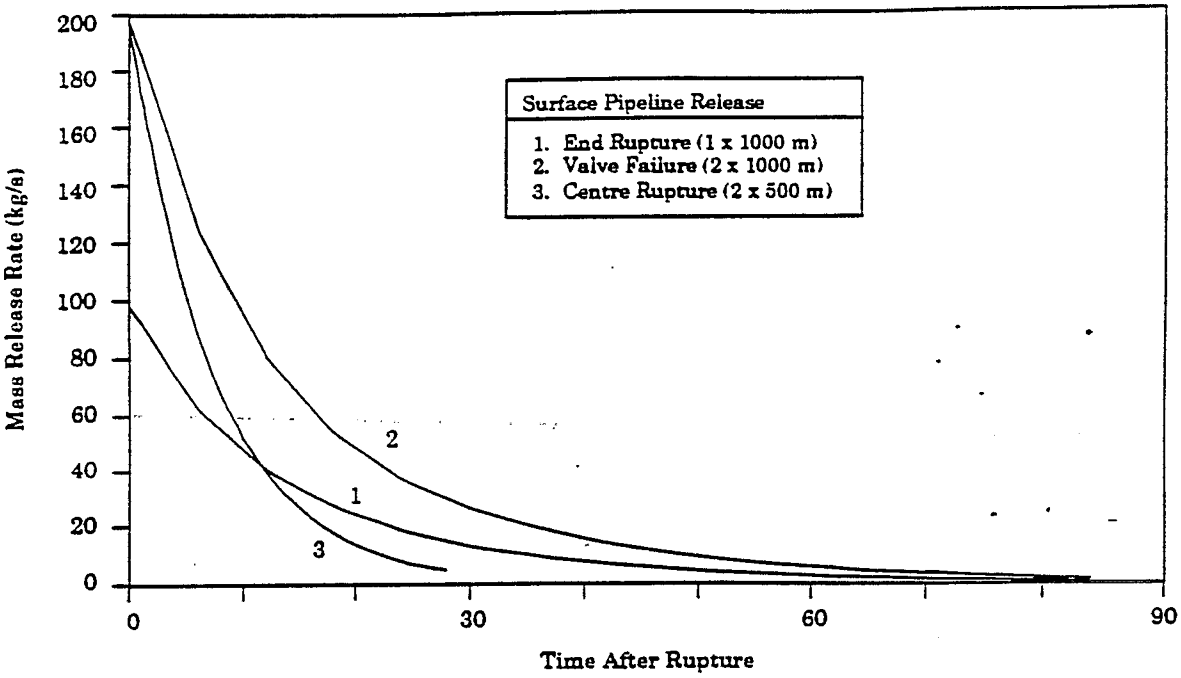
Source: Alp et al., 1990.

Figure III-19. Possible pipeline rupture scenarios.



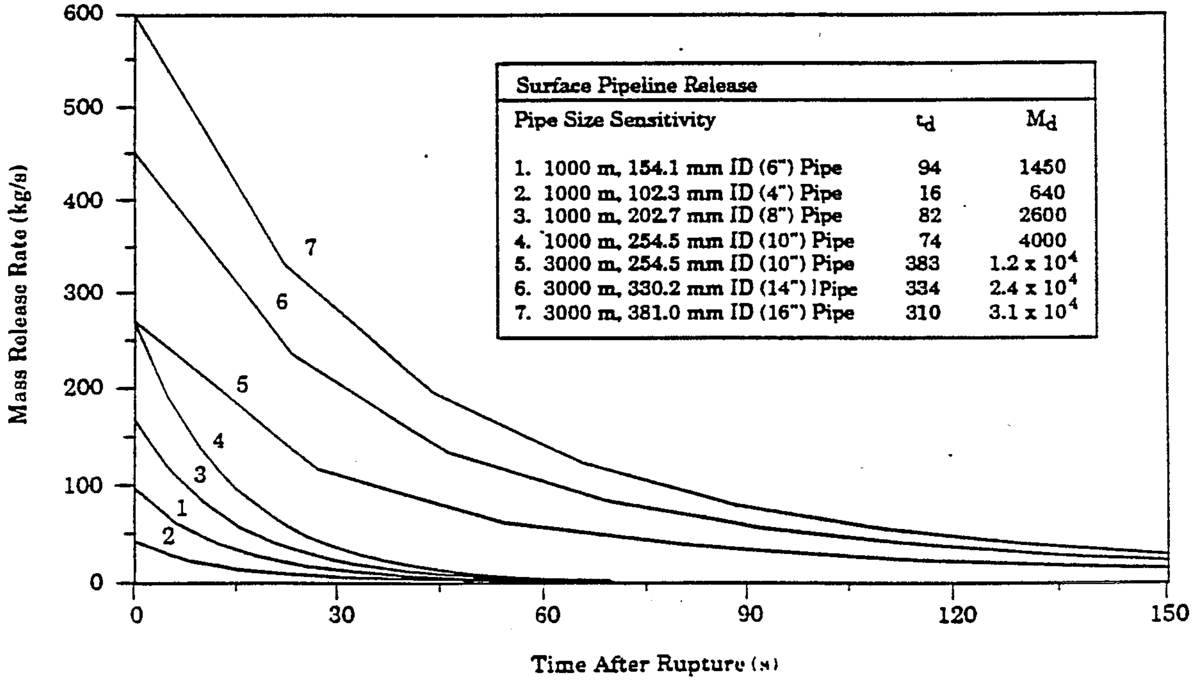
Source: Alp et al., 1990.

Figure III-20. Possible pipeline release geometries.



Source: Alp et al., 1990.

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



Source: Alp et al., 1990.

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

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

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

Consequence Analysis of Flare Stack Releases

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

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

Consequence Analysis of Releases Collecting at Ground Level

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

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

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

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

Accidental Releases—Prevention, Mitigation, and Emergency Response

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

Process Safety Management

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

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

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

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

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

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

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

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

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

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

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

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

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

Major Safety Considerations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Abandonment Practices

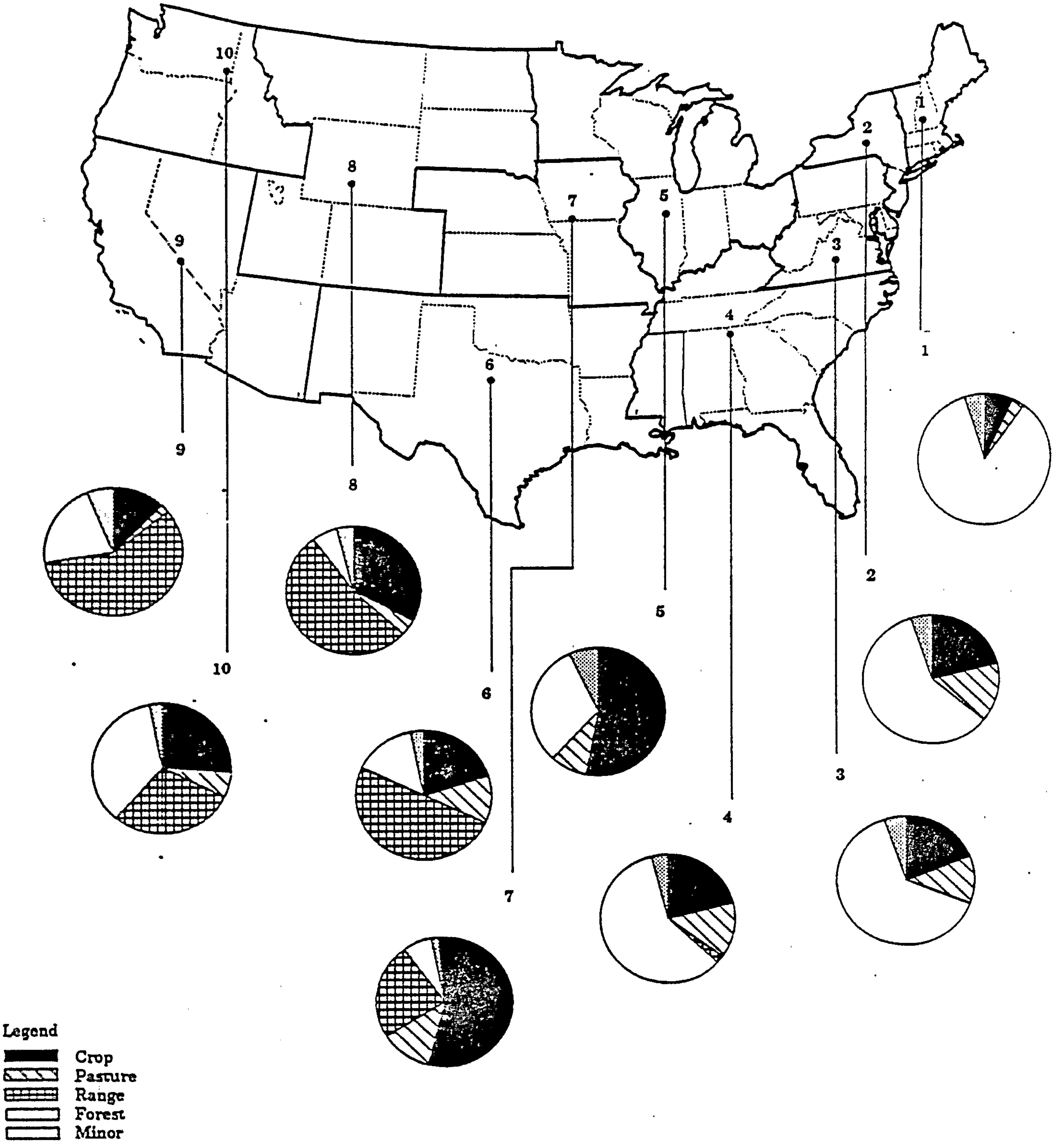
The termination of sour oil and gas production operations normally results in the plugging of the well with cement prior to abandonment by the operator. As a result, a potential exists for H_2S to be released from sour oil and gas from the well and associated equipment if proper precautions are not taken.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

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

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

Land Use Around Well Sites

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



Source: Southerland, 1992.

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

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

Affected Human Populations

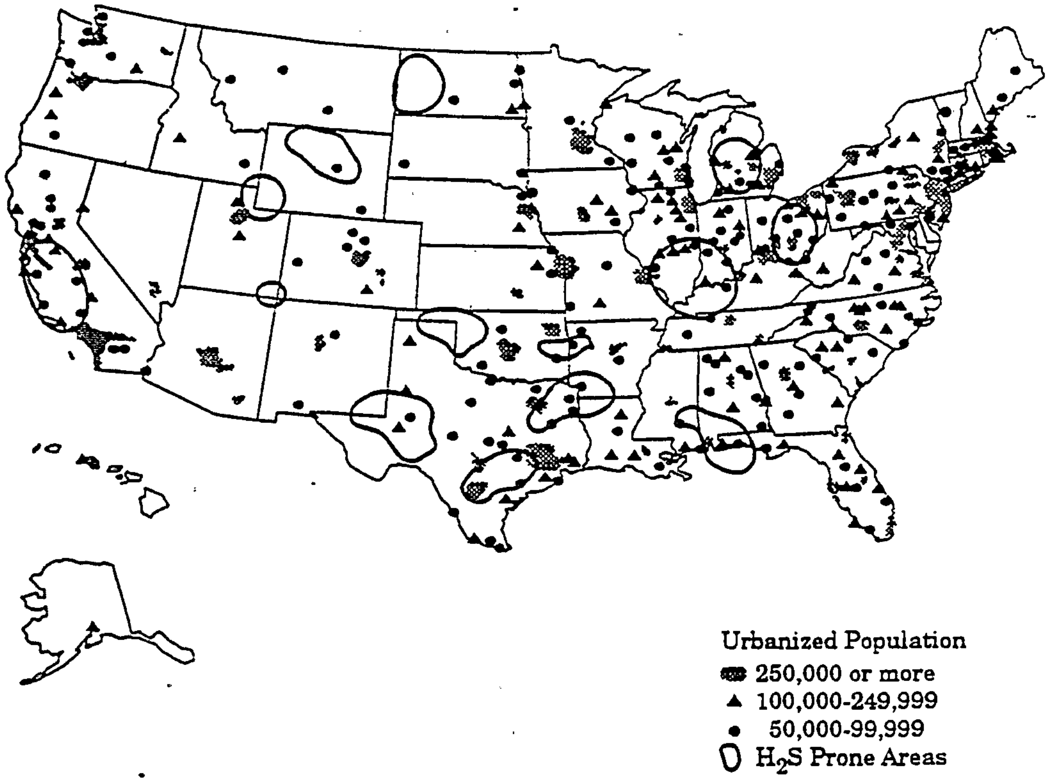
Figure III-24 overlays 1980 census data on the H_2S prone areas to show the proximity of major populations to H_2S deposits. The figure shows that a wide range in population density can be found in H_2S deposit areas. However, a look at the locations of well fields in the United States (Figure III-11)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

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

Affected Environmental Settings

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

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



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

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

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

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

FINDINGS

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

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

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

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

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

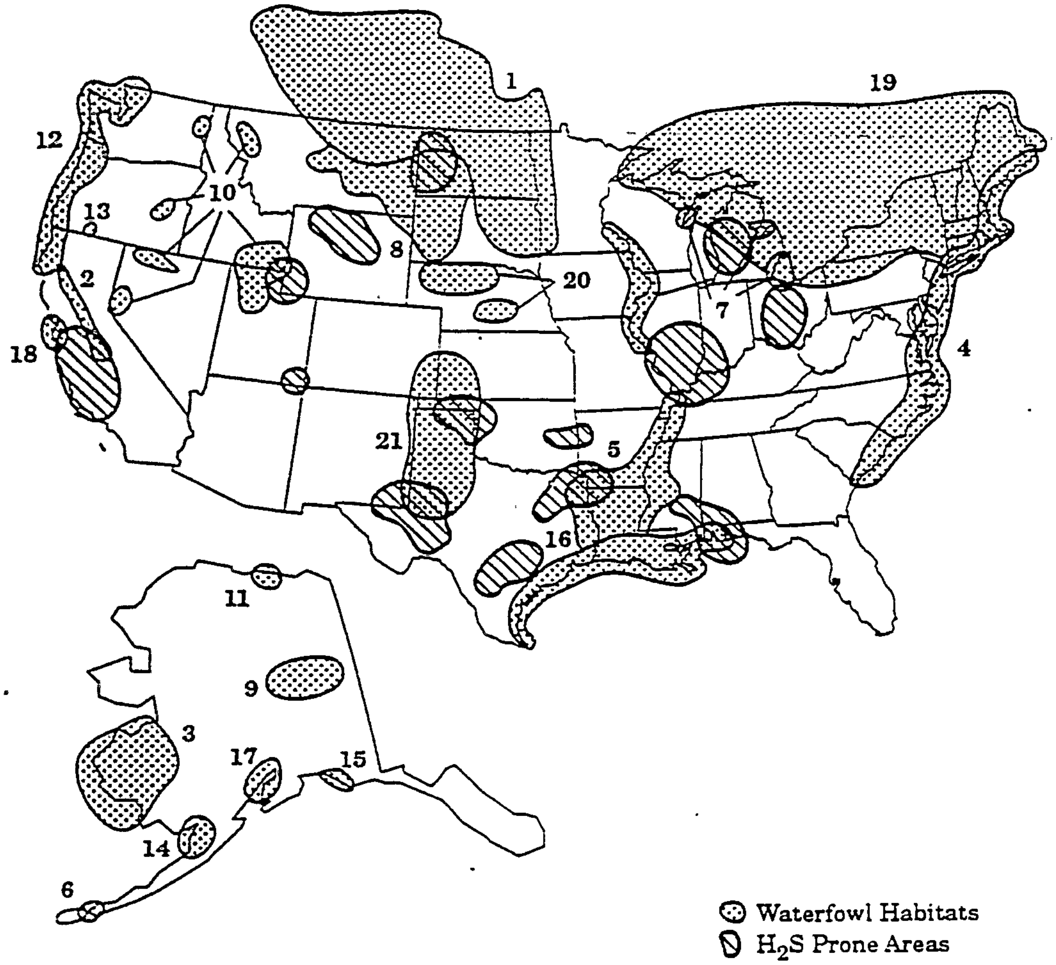
6. High exposure studies have shown young, growing plants to be the most susceptible to H_2S injury (clover, soybean, tomatoes, tobacco, buckwheat).

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

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

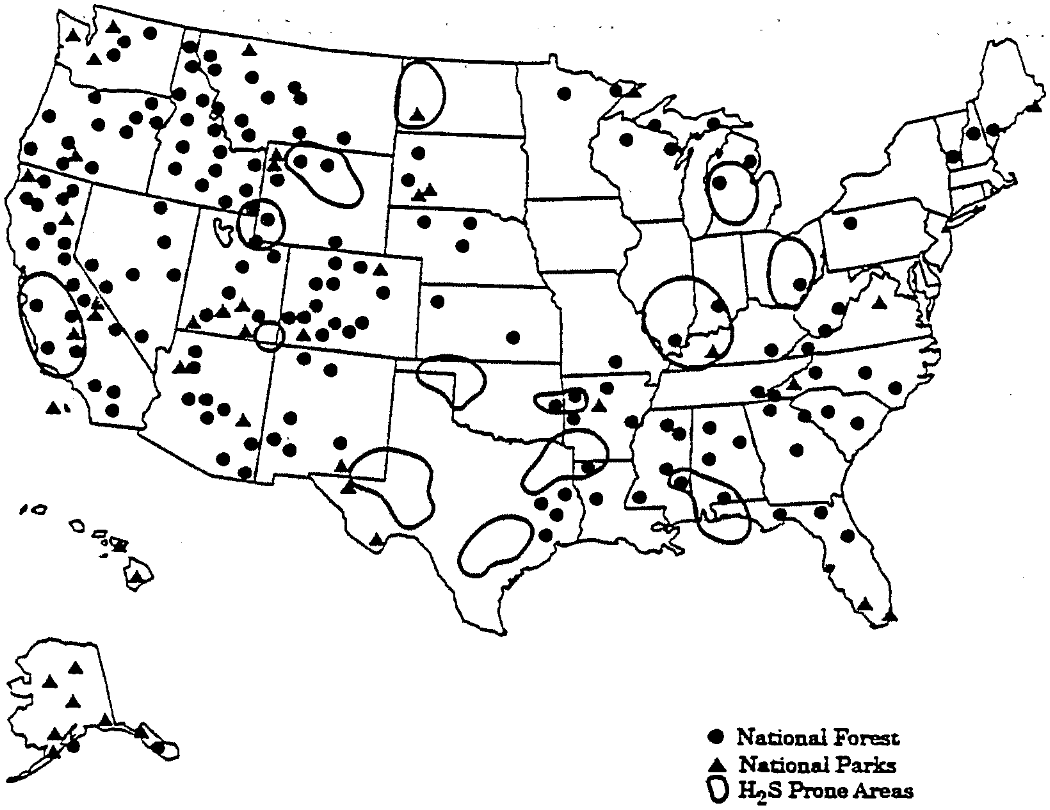
9. North Dakota is the only State known to have routinely monitored ambient H_2S at well sites and surrounding areas.

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



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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

limited access by facilitating quicker mitigation. These technologies include:

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

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

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

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

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

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

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

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

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

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

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

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CHAPTER IV

REGULATORY PROGRAMS AND RECOMMENDED INDUSTRY PROCEDURES

INTRODUCTION

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

STATE REGULATIONS

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

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

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

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

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

Table IV-1. Ambient Air Quality Standards for H_2S

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

[a] Not to be exceeded more than two times/year.

[b] Not to be exceeded more than two times/five consecutive days.

[c] Not to be exceeded more than one time/year.

[d] Not to be exceeded more than one time/month.

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

Selected Oil and Gas Producing States

Oklahoma

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

The following agencies regulate oil and gas activities in Oklahoma:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Texas

Six agencies regulate oil and gas activities in Texas:

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

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

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

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

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

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

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

Michigan

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

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

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

Five agencies regulate oil and gas activities in Michigan:

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

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

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

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

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

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

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

California

The following agencies regulate oil and gas activity in California:

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

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

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

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

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

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

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

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

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

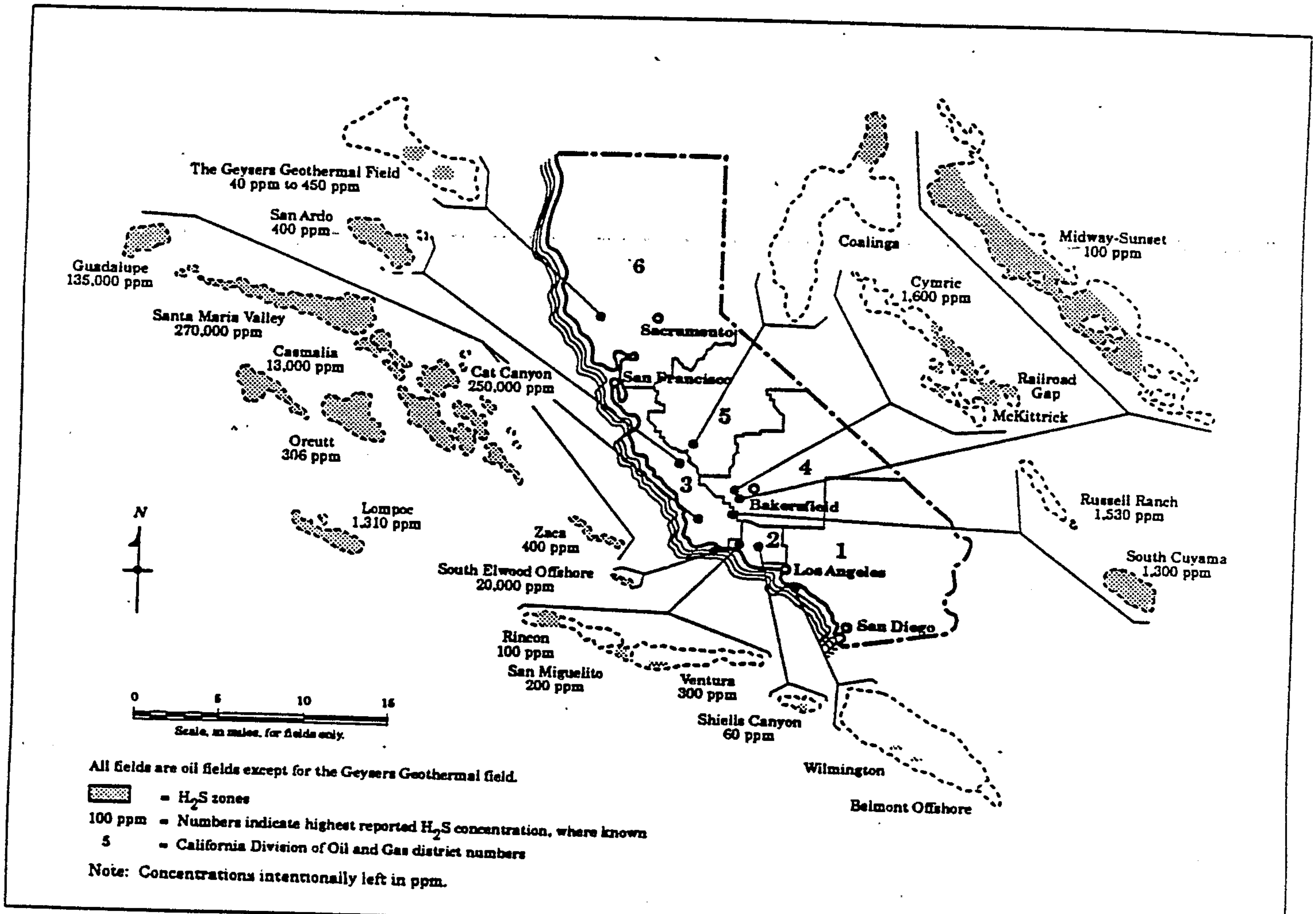
District 3 has 1,929 producing wells and 2,845 shut-in wells (i.e., no production is made on the well; its pump is turned off, the stuffing box is closed, and it is inspected to ensure no leakage). Three field inspectors cover District 3 (personal communication, A. Kollar, CDOG, 8/28/92).

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

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

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

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



Source: Dosch and Hodgson, 1986.

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

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

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

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

Source: Dosch and Hodgson, 1986.

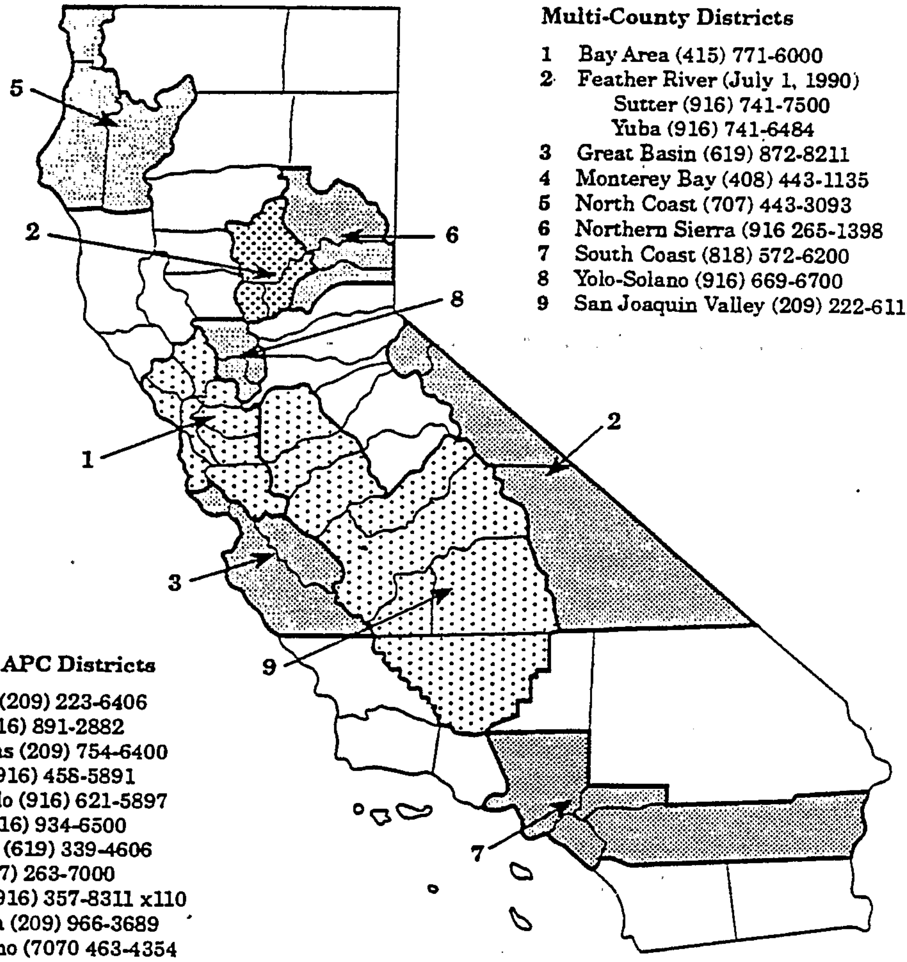
enforcing air quality rules tailored to the district's needs. Districts with significant oil production are:

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

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

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

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



Multi-County Districts

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

County APC Districts

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

Source: California Air Resources Board, 1991.

Figure IV-2. Multi-county districts.

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

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

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

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

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

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

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

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

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

A Comparison of H_2S Regulatory Programs in Four States

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

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

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

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

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

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

Other Large Producing States

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

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

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

*Enforcement staff in California (example counties)

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

Louisiana

Five agencies regulate oil and gas activity in Louisiana:

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

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

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

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

New Mexico

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

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

- U.S. Bureau of Land Management.

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

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

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

North Dakota

Five agencies regulate oil and gas activities in North Dakota:

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

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

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

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

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

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

Pennsylvania

Six agencies regulate oil and gas activities in Pennsylvania:

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

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

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

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

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

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

Wyoming

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

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

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

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

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

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

FEDERAL REGULATORY PROGRAMS

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

OSHA Regulations

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

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

Current Regulations

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

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

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

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

The OSHA requirements for employers include standards to:

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

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

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

[b] Recommended standard.

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

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

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

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

5) Provide training to employees;

6) Evaluate and monitor contractor safety standards and performance;

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

8) Establish maintenance systems for critical process related equipment;

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

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

11) Establish and implement a plant emergency action plan.

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

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

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

Proposed Regulations

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

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

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

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

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

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

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

Impact of OSHA Regulations on Occupational and Human Health

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

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

National Institute for Occupational Safety and Health

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

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

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

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

Bureau of Land Management

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

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

Minerals Management Service

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

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

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

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

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

CERCLA and EPCRA

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

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

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

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

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

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

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

Clean Air Act Section 112(r) - Accident Prevention

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

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

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

Clean Air Act - PSD Program

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

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

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

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

INDUSTRY-RECOMMENDED SAFETY AND ENVIRONMENTAL PROTECTION PROCEDURES

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

API Recommended Practices

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

Control Standards

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

Control Techniques

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FINDINGS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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CHAPTER V
RECOMMENDATIONS

ROUTINE EMISSIONS

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

ACCIDENTAL RELEASES

General

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

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

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

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

Facility and Local Emergency Planning Committee (LEPC)

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

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

Preparedness and Response

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

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

Research and Further Studies

- Further study on the acute exposure levels of H_2S that result in irreversible health effects or lethality in humans should be continued in order to improve emergency planning tools such as atmospheric dispersion models.
- Further research on the effects of surface roughness and obstacles on dense-gas dispersion behavior should be continued to determine their influences on toxic substance concentrations in a dispersing vapor cloud. The Liquefied Gaseous Fuels Spill Test Facility could be used for spill tests to assist in this research.
- EPA should continue to study the issues surrounding worst-case releases, their consequences, and the likelihood of worst-case or other significant releases for extremely hazardous substances and the role and relationship of these issues to prevention, preparedness, and response.

GLOSSARY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Drill site: The location of a drilling rig.

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

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

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

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

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

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

EPA: United States Environmental Protection Agency.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Volatile: Readily vaporized.

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

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

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

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

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

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

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

EXPLORATION AND DEVELOPMENT

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

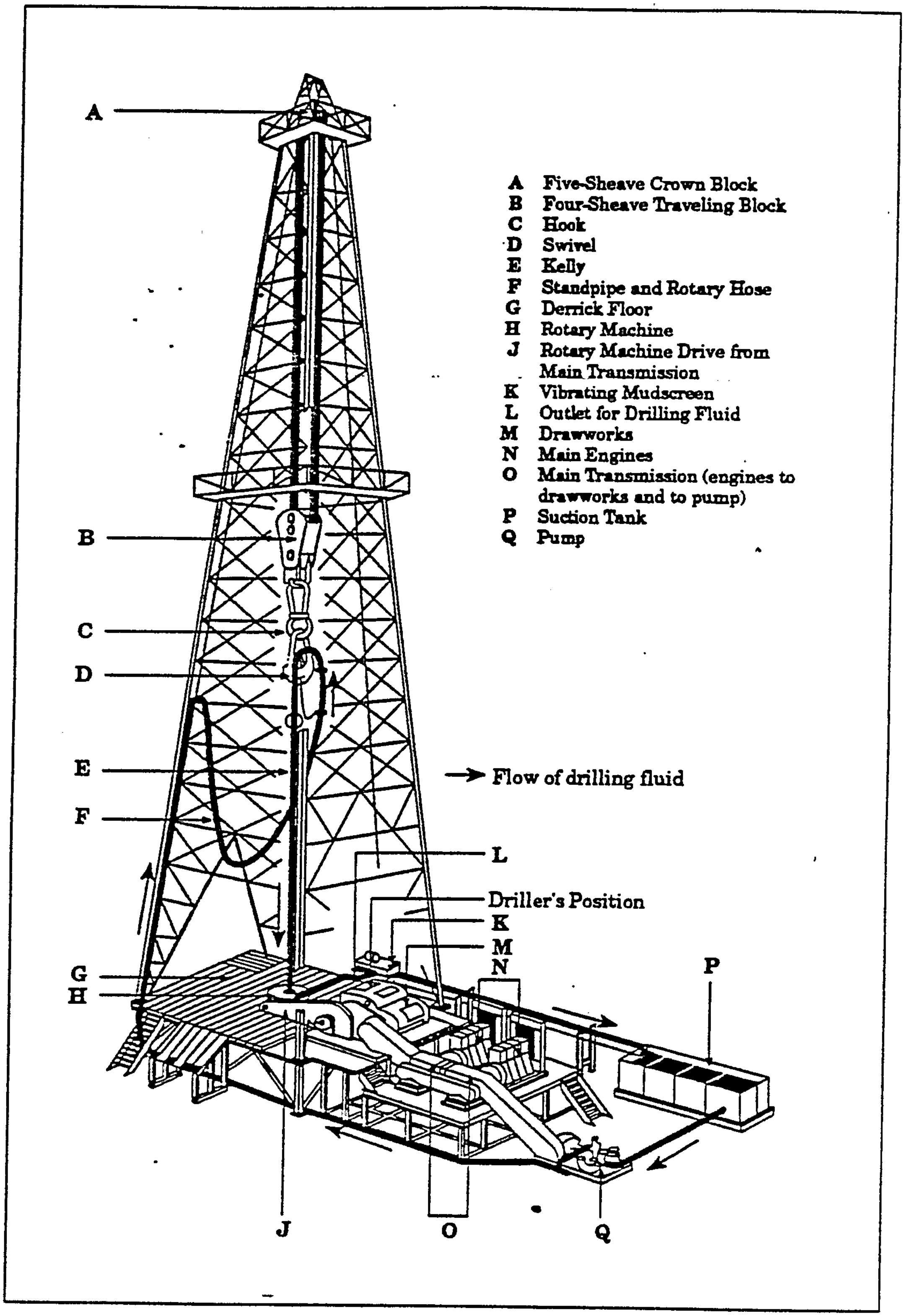
Rotary drilling, the primary drilling method in the United States, provides a safe way to control high-pressure oil/gas/water flows and allow for the simultaneous drilling of the well and removal of cuttings. This makes it possible to drill wells over 30,000 feet deep. Figure A-1 illustrates the process.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

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

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

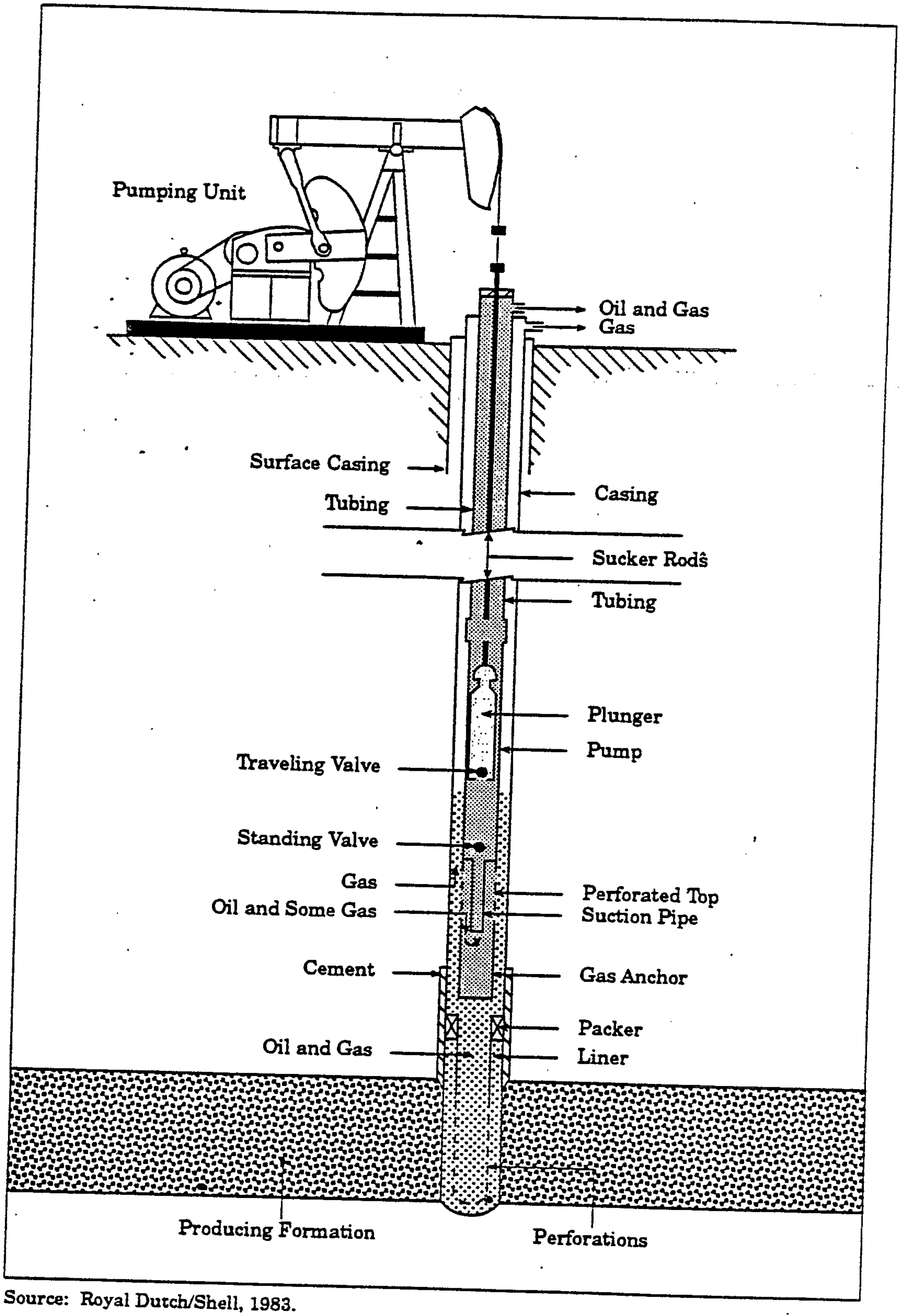
HOW OIL AND GAS ARE PRODUCED

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



Source: Royal Dutch/Shell, 1983.

Figure A-1. Rotary drilling rig.



Source: Royal Dutch/Shell, 1983.

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

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

Downhole Operations

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

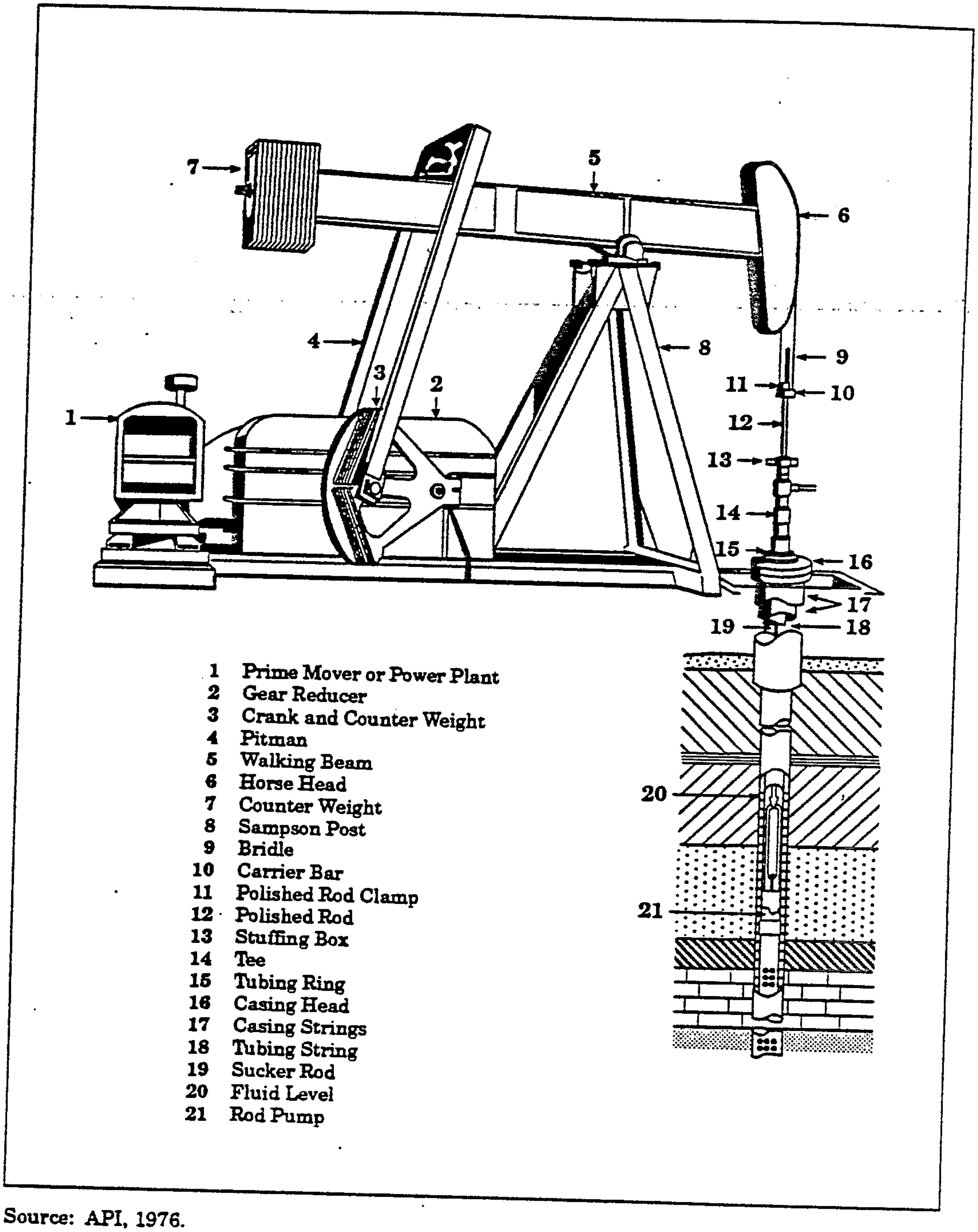
During the primary recovery stage, natural pressure in the reservoir may decline and artificial lift may be needed. One of three general types of pumps may be used: (1) pumps at the bottom of the hole run by a string of rods; (2) pumps at the bottom of the hole run by high-pressure liquids; and (3) bottom-hole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

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

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

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

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



Source: API, 1976.

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

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

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

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

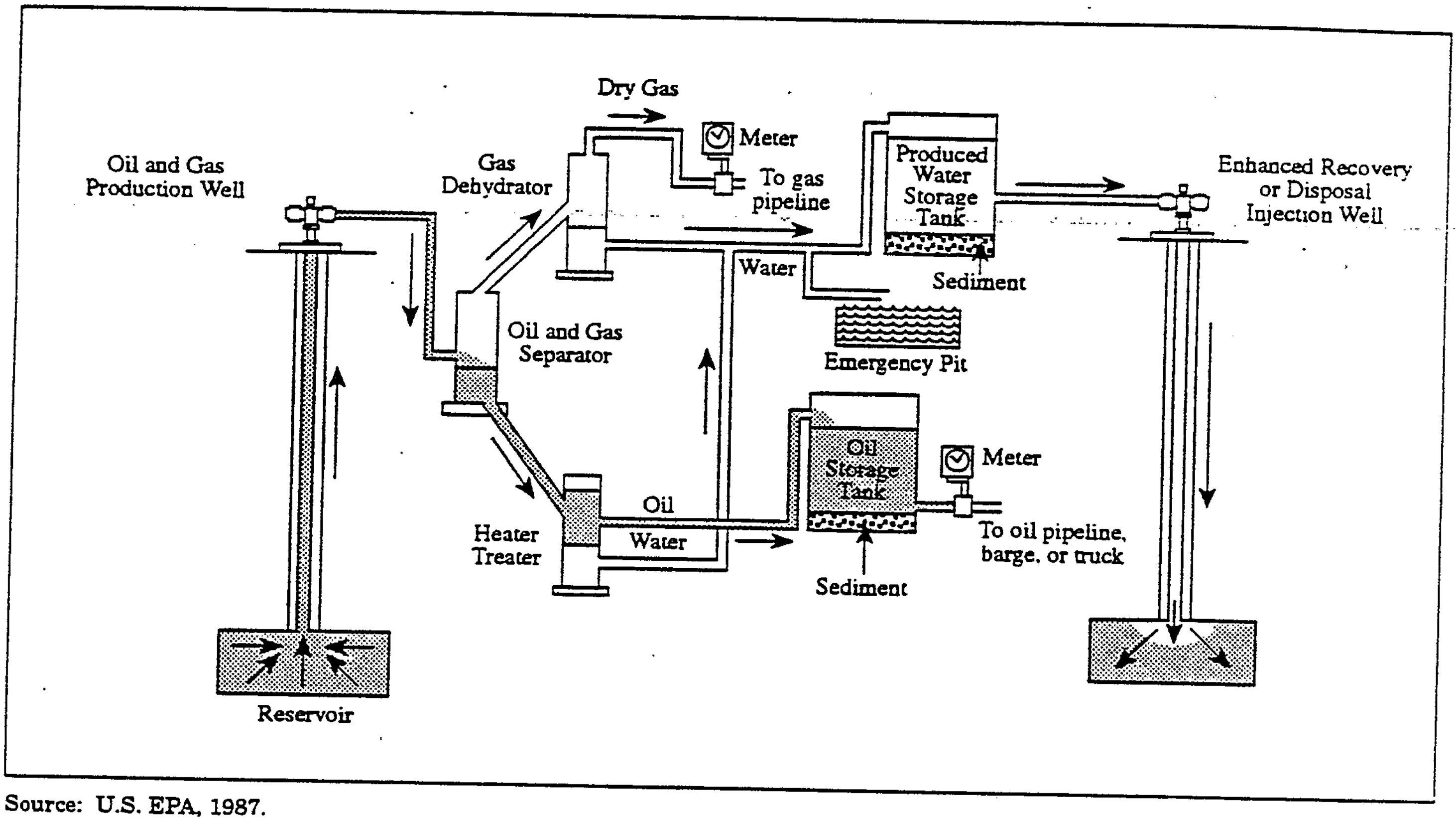
Surface Operations

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

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

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

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



Source: U.S. EPA, 1987.

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

/

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

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

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

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

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

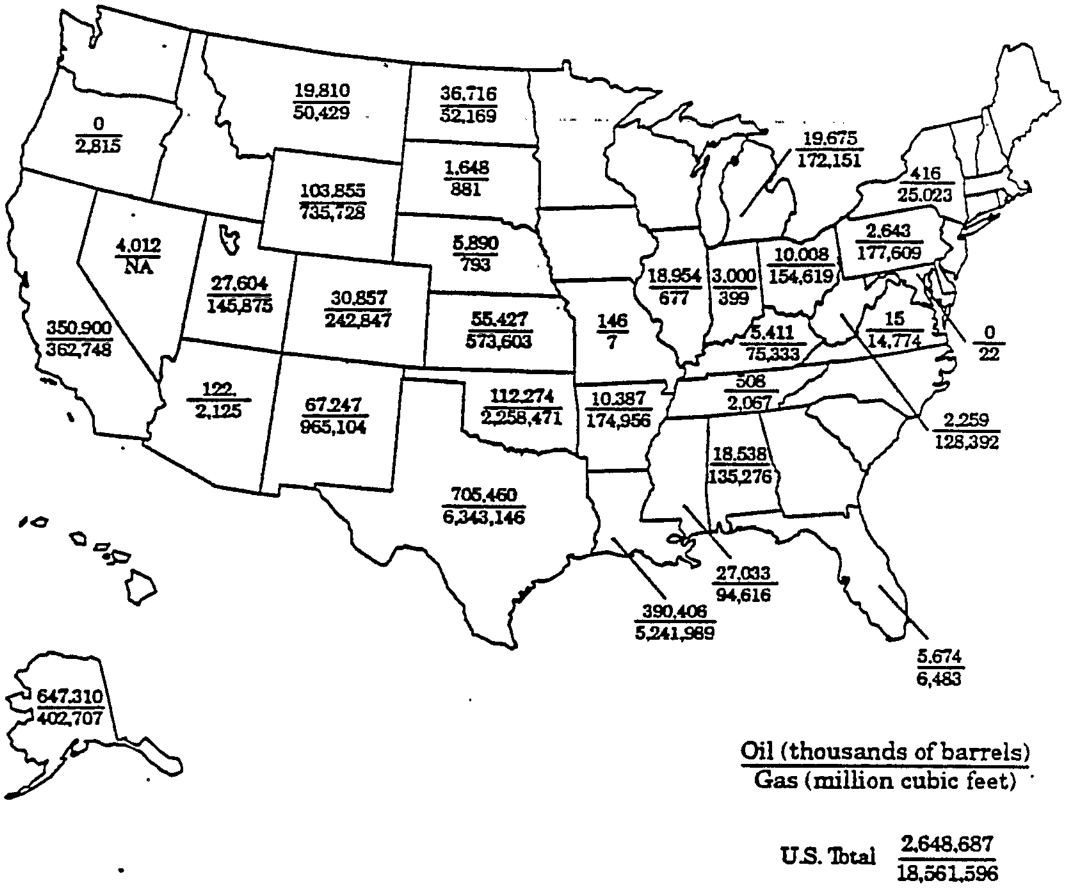
OVERVIEW OF THE INDUSTRY

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

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

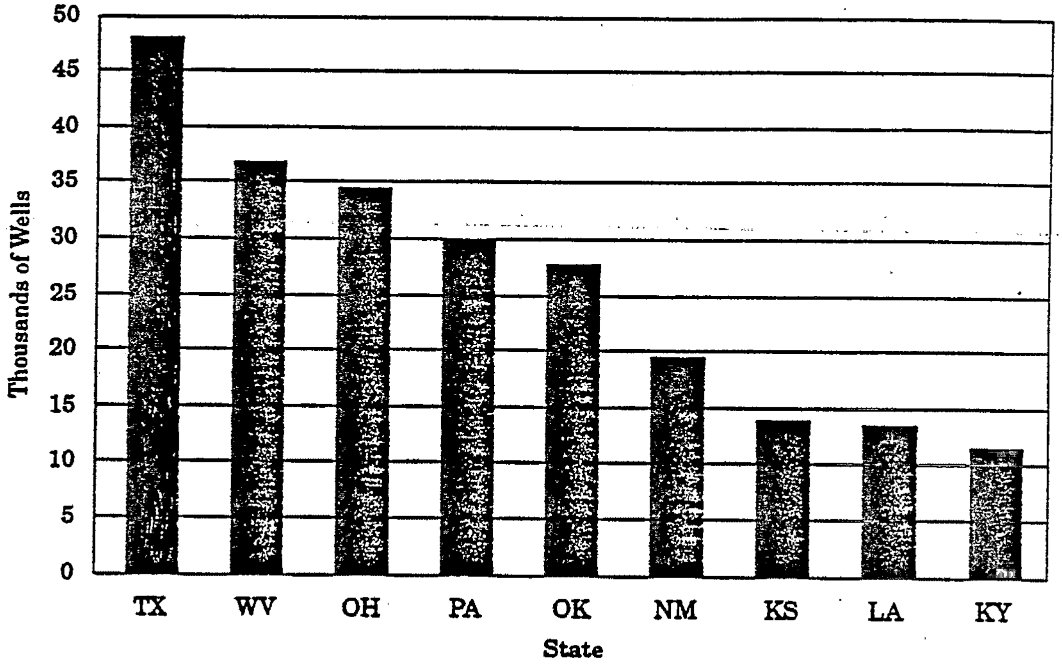
State	Number of Producing Oil Wells[a]	Oil Production (thousands of barrels)[b]	Number of Producing Gas Wells[a]	Gas Production (million cubic feet)[b]
Alabama	872	18,538	2,038	135,276
Alaska	1,466	647,310	109	402,907
Arizona	22	122	NA	2,125
Arkansas	7,265	10,387	3,460	174,956
California	43,375	350,900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

Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:
[a] World Oil.
[b] Energy Information Administration.
–NA Not available.



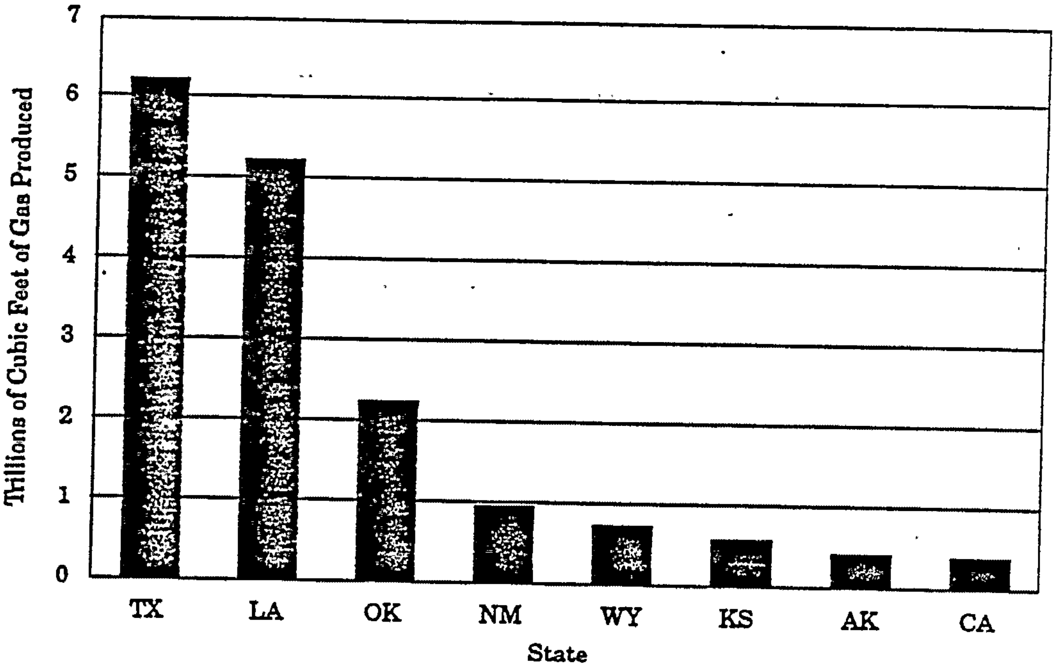
Combined Source: Petroleum Independent, September 1992, attributes the oil and gas sources to: World Oil Energy Information Administration.

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



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

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



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

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

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

Principal Production Industry Groups

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

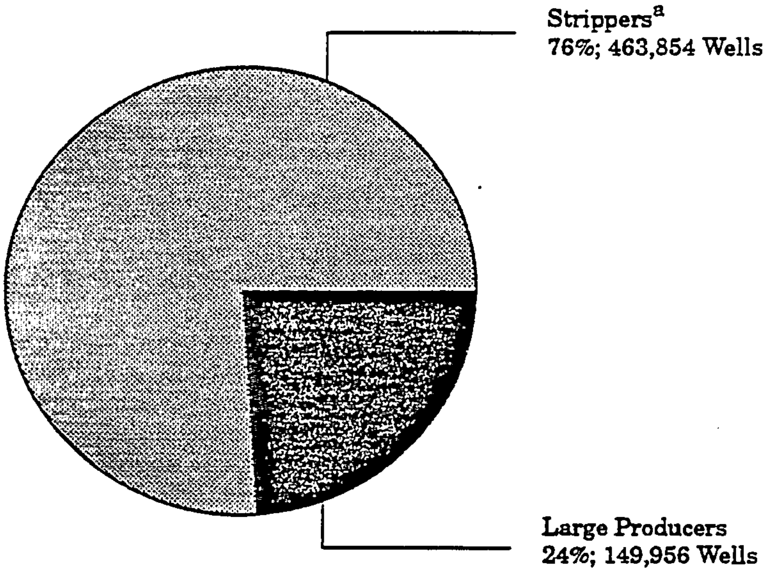
The second group is the large independents. These companies primarily explore, develop, and produce oil and gas, but do not perform downstream activities. Some large independents produce oil and gas only, while others provide such additional services as contract drilling and pipeline operations.

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

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

Diversity of Production

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



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

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

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

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

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

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

[a] World Oil.

[b] Energy Information Administration.

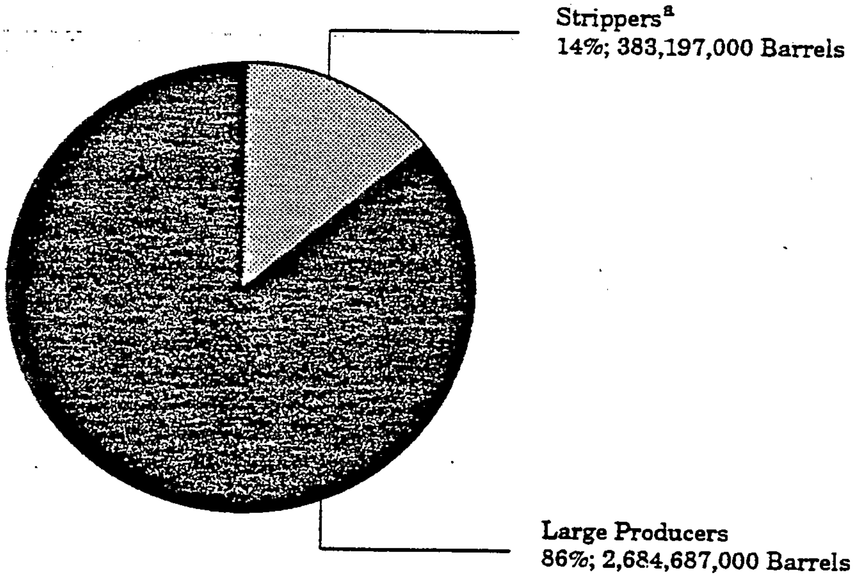
[c] Interstate Oil and Gas Compact Commission and National Stripper Well Association.

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

NA Unable to calculate.

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

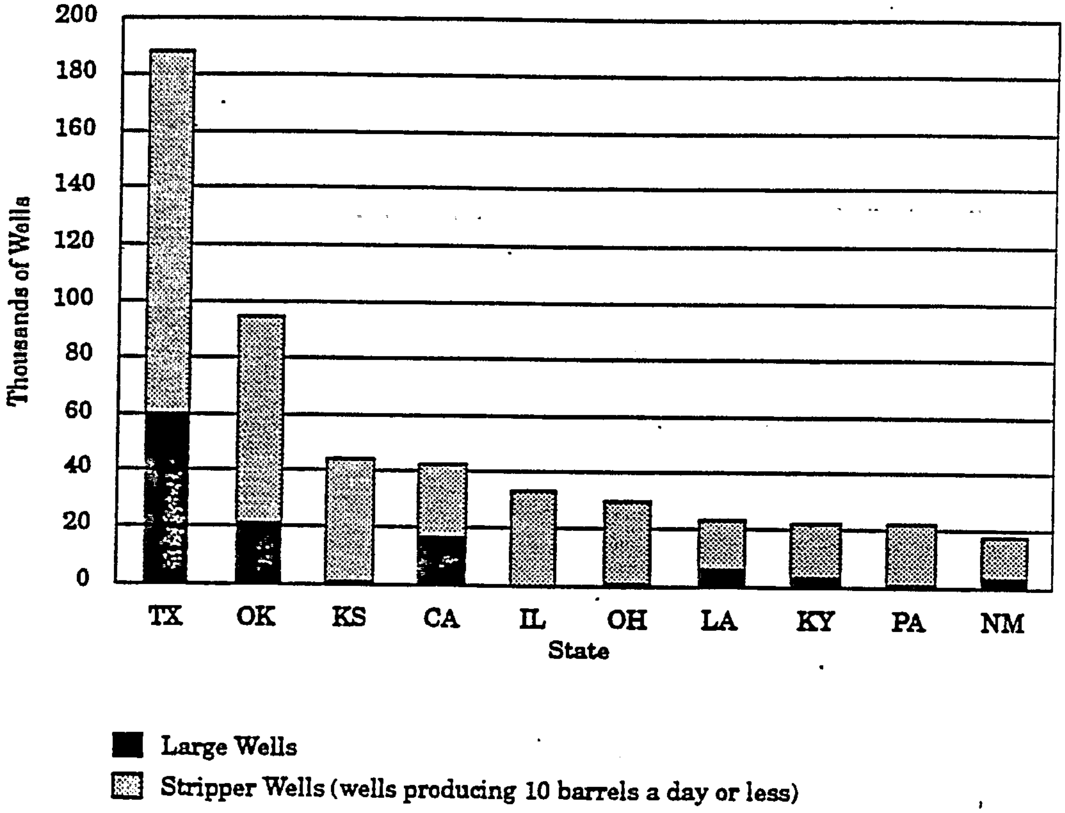
Amount of Crude Oil Produced from Stripper Wells (thousands of barrels)[c]	Percentage of Crude Oil Produced from Stripper Wells
1,486	8%
0	0%
26	21%
5,693	55%
36,405	10%
5,698	19%
0	0%
18,520	93%
3,002	NA*
40,873	74%
4,338	80%
7,154	2%
4,599	23%
802	3%
120	82%
2,449	12%
2,011	34%
0	0%
14,296	21%
383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



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

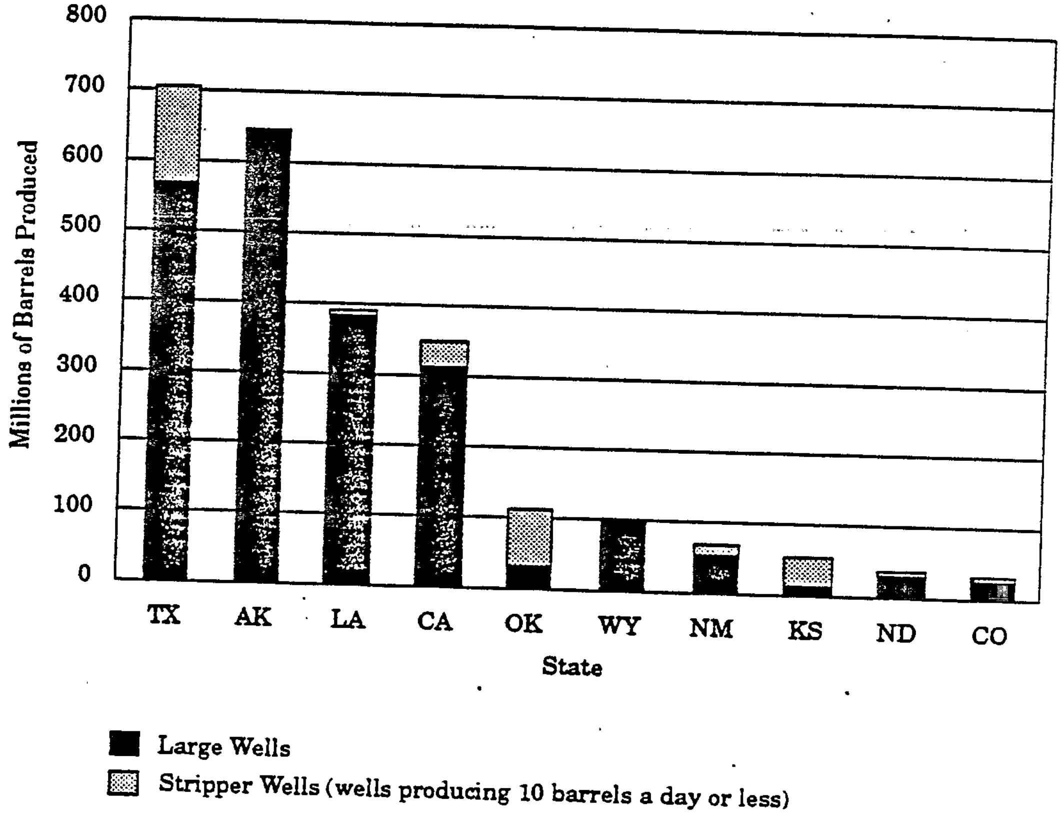
Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

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



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

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



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

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

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APPENDIX B

SUBJECTS OF STATE H_2S REGULATIONS AND GUIDELINES

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

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

NA Not available in reviewed literature.

• The subject was identified under the State's H_2S regulations or guidelines.

A Rule 36 references API RP19.

NJ Not under Congressional jurisdiction.

MMIOSH Required by Michigan OSHA.

*CA grants the supervisor of the Oil and Gas Division discretionary authority to control H_2S releases.

APPENDIX C

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

APPENDIX C

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

INTRODUCTION

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

SUMMARY INPUT AND OUTPUT DATA

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

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

TABLE C-1

SUMMARY OF INPUT AND OUTPUT DATA WELLHEAD BLOWOUT SCENARIOS

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

[a] Scenarios from Table III-7.

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

* E=Extreme Case.

TABLE C-2

PIPE RUPTURE SCENARIOS INPUTS AND OUTPUTS (SADENZ MODEL)

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

---

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

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

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

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

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

SAMPLE SLAB CALCULATIONS

SLAB Input

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Line 19: XFFM is the maximum downwind extent of the calculation. A value of 10 km is used in order to obtain cloud concentration results at large distances away from the release. It is set to 2×10^4 m, which should be enough to ensure that any results of interest lie within this distance.

Lines 20-23: ZP(I) allows the user to specify up to four heights at which the concentration is calculated as a function of downwind distance. ZP(1) is set to 1.6 m (approximate head elevation above grade). The remaining ZP(I)s are zero, which means that SLAB only considers the first height.

Lines 24-29: These lines specify the meteorological conditions. ZO is the surface roughness length, which is set to 0.1 m, depicting a relatively smooth surface. ZA is the height at which the windspeed is measured (10 m). UA is the windspeed at height ZA (1.5 m/s). TA is the ambient temperature (273K). RH is the relative humidity (75%, chosen as being typical of Category F weather conditions). Finally, STAB is the stability class (F=stable). The weather conditions (Category F with a low windspeed of 1.5 m/s) have been chosen to simulate unfavorable (close to worst case) conditions.

Line 30: TER is the end of file designator. TER < 0 terminates the run.

SLAB Output

A partial SLAB output corresponding to the inputs of Table C-3 is given in Table C-4. The interpretation is as follows. The first column gives the downwind distance, x. The second column gives the time at which the maximum concentration arrives at x and the third gives the duration of cloud passage. As can be seen, the duration of passage remains equal to the duration of release until the cloud has traveled several kilometers downwind. The fourth column gives the approximate half-width of the plume, bbc. The remaining six columns give the average concentration (volume fraction) at a height of 1.6 m (as chosen in the SLAB input) for six off-axis distances that are multiples of bbc, 0.5, 1.0, 1.5, etc. The predicted concentrations are zero close in because the plume was arbitrarily released at a height of 5 m. As the plume broadens, the concentrations at height 5 m rise above zero to a maximum at about 25 m to 30 m downwind and then begin to decline as the plume dilutes further.

The effective ERPG-2 is 100 ppm and the effective LC_{01} is about 4.7 x 10^5 ppb. These number values are derived as follows: the ERPG-2 for pure H_2S for an exposure time of 1 hour is 3 x 10^4 ppb. The volume concentration of H_2S in composition D is 30 percent (see Table III-5). Therefore, the overall concentration of the total released material when the H_2S in it is at 3 x 10^4 ppb is 30/0.3 = 1 x 10^5 ppb. Similarly, the LC_{01} for pure H_2S is 1.4 x 10^5 ppb for an exposure time of 1 hour (see Chapter III). Therefore, the effective LC_{01} for the plume is 140/0.3 = 4.7 x 10^5 ppb. As explained in Chapter III, the ERPG-2 is regarded as a threshold at which emergency response might be necessary and the LC_{01} is an approximate threshold for the occurrence of fatalities among the affected population. Reading down the column headed "y/bbc=0," the concentrations first fall below 4.7 x 10^5 ppb (= a volume fraction of 4.7×10^{-4}) at a distance of about 3 km and below 1 x 10^5 ppb (= a volume fraction of 1.0×10^{-4}) at a distance of about 7 km.

SAMPLE DEGADIS CALCULATIONS

DEGADIS Input

Table C-5 displays the DEGADIS input for the same case as was prepared for SLAB in Table C-3 except that DEGADIS can only simulate a vertical jet release. The chosen values for most of the parameters have already been explained in the section on SLAB.

Lines 1-4 allow the user to input up to four lines of title.

Line 5 requires the windspeed (1.5 m/s) and the height at which the windspeed is measured (10 m).

Line 6 gives the surface roughness length (0.1 m).

Line 7 requires the parameter INDVEL, the atmospheric stability category (F=6) and the Monin-Obukhov length RML. For INDVEL=1 (the present case) the model calculates RML from the stability category and the surface roughness length, so the user does not need to specify a value for RML.

Line 8 requires the ambient temperature (273K), the ambient pressure (1 atmosphere) and the relative humidity (75%).

Line 9 gives the surface temperature, which is here set equal to the ambient temperature (273K).

Line 10 is a name for the released gas, in this case CPD for ComPosition D.

Line 11 is the molecular weight, 25.2.

Line 12 is the averaging time, taken to be equal to the duration of release, 3,600 s. It is used to calculate the increase in the effective width of the plume as a function of exposure time.

Line 13 is the temperature of the released gas, 273K.

Line 14 contains the upper level of concern (470 ppm, expressed as a volume fraction), the lower level of concern (100 ppm) and the height at which the concentrations are calculated (1.6 m).

Line 15 contains first a variable INDHT=0, meaning that heat transfer from the ground is not included, which does not matter here because the plume, air, and ground all have the same temperature. The second entry is the specific heat of the released gas at constant pressure (1,500 J/kg/K). The third entry, CPP=0, indicates that an approximation was made in which the specific heat does not vary with temperature.

Line 16 is a parameter "NDEN" that is used to specify the density profile of the released material. For NDEN=0, the release is assumed to be an ideal gas with specific heat at constant pressure 1500J/kg/K. Water condensation effects are taken into account.

Line 17 is the mass rate of release, 7.69 kg/s.

Table C-3. SLAB Input - Horizonal Wellhead Release

Value	Parameter	Line No.
2 (horizontal), 3 (vertical)	IDSPL	1
1	NCALC	2
0.0289	WMS	3
1500.	CPS	4
111.50	TBP	5
0.0	CMEDO	6
509,880.	DHE	7
3,349.	CPSL	8
1,000.	RHOSL	9
-1.0	SPB	10
0.0	SPC	11
273.	TS	12
7.69	QS	13
1.93×10^{-2}	AS	14
3,600.	TSD	15
0.	QTIS	16
5.	HS	17
3,600.	TAV	18
20,000.	XFFM	19
1.6	ZP(1)	20
0.	ZP(2)	21
0.	ZP(3)	22
0.	ZP(4)	23
0.1	ZO	24
10.	ZA	25
1.5	UA	26
273.	TA	27
75.	RH	28
F	STAB	29
-1.	TER	30

Table C-4. Partial SLAB Output

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc = 0.0	0.5	1.0	1.5	2.0	2.5
1.00	1.80×10^{3}	3.60×10^{3}	6.95×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.02	1.80×10^{3}	3.60×10^{3}	7.73×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.05	1.80×10^{3}	3.60×10^{3}	8.71×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.08	1.80×10^{3}	3.60×10^{3}	9.92×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.13	1.80×10^{3}	3.60×10^{3}	1.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.18	1.80×10^{3}	3.60×10^{3}	1.32×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.24	1.80×10^{3}	3.60×10^{3}	1.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.32	1.80×10^{3}	3.60×10^{3}	1.81×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.41	1.80×10^{3}	3.60×10^{3}	2.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.52	1.80×10^{3}	3.60×10^{3}	2.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.66	1.80×10^{3}	3.60×10^{3}	3.03×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.84	1.80×10^{3}	3.60×10^{3}	3.63×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
2.05	1.80×10^{3}	3.60×10^{3}	4.36×10^{-1}	8.35×10^{-41}	5.76×10^{-41}	1.88×10^{-41}	2.84×10^{-42}	1.93×10^{-43}	5.61×10^{-45}
2.31	1.80×10^{3}	3.60×10^{3}	5.24×10^{-1}	1.18×10^{-28}	8.13×10^{-29}	2.65×10^{-29}	4.02×10^{-30}	2.79×10^{-31}	8.76×10^{-33}
2.63	1.80×10^{3}	3.60×10^{3}	6.31×10^{-1}	3.14×10^{-20}	2.16×10^{-20}	7.03×10^{-21}	1.07×10^{-21}	7.54×10^{-23}	2.42×10^{-24}
3.01	1.80×10^{3}	3.60×10^{3}	7.61×10^{-1}	1.99×10^{-14}	1.37×10^{-14}	4.45×10^{-15}	6.79×10^{-16}	4.82×10^{-17}	1.58×10^{-18}
3.49	1.80×10^{3}	3.60×10^{3}	9.17×10^{-1}	1.86×10^{-10}	1.28×10^{-10}	4.16×10^{-11}	6.36×10^{-12}	4.55×10^{-13}	1.51×10^{-14}
4.08	1.80×10^{3}	3.60×10^{3}	1.10	9.38×10^{-8}	6.45×10^{-8}	2.10×10^{-8}	3.21×10^{-9}	2.30×10^{-10}	7.71×10^{-12}
4.79	1.80×10^{3}	3.60×10^{3}	1.33	6.31×10^{-6}	4.34×10^{-6}	1.41×10^{-6}	2.16×10^{-7}	1.55×10^{-8}	5.23×10^{-10}
5.67	1.80×10^{3}	3.60×10^{3}	1.60	1.07×10^{-4}	7.33×10^{-5}	2.38×10^{-5}	3.65×10^{-6}	2.63×10^{-7}	8.89×10^{-9}
6.75	1.80×10^{3}	3.60×10^{3}	1.91	6.99×10^{-4}	4.81×10^{-4}	1.56×10^{-4}	2.39×10^{-5}	1.73×10^{-6}	5.87×10^{-8}
8.07	1.80×10^{3}	3.60×10^{3}	2.28	2.41×10^{-3}	1.66×10^{-3}	5.37×10^{-4}	8.24×10^{-5}	5.95×10^{-6}	2.03×10^{-7}
9.68	1.80×10^{3}	3.60×10^{3}	2.72	5.35×10^{-3}	3.68×10^{1}	1.19×10^{-3}	1.83×10^{-4}	1.32×10^{-5}	4.51×10^{-7}
1.17×10^{1}	1.80×10^{3}	3.60×10^{3}	3.22	8.87×10^{-3}	6.09×10^{-3}	1.98×10^{-3}	3.03×10^{-4}	2.19×10^{-5}	7.48×10^{-7}
1.41×10^{1}	1.81×10^{3}	3.60×10^{3}	3.79	1.22×10^{-2}	8.38×10^{-3}	2.72×10^{-3}	4.17×10^{-4}	3.02×10^{-5}	1.03×10^{-6}
1.71×10^{1}	1.81×10^{3}	3.60×10^{3}	4.43	1.49×10^{-2}	1.03×10^{-2}	3.33×10^{-3}	5.11×10^{-4}	3.70×10^{-5}	1.27×10^{-6}
2.07×10^{1}	1.81×10^{3}	3.60×10^{3}	5.11	1.69×10^{-2}	1.16×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
2.52×10^{1}	1.81×10^{3}	3.60×10^{3}	5.79	1.82×10^{-2}	1.25×10^{-2}	4.05×10^{-3}	6.22×10^{-4}	4.50×10^{-5}	1.54×10^{-6}
3.07×10^{1}	1.81×10^{3}	3.60×10^{3}	6.55	1.84×10^{-2}	1.27×10^{-2}	4.11×10^{-3}	6.31×10^{-4}	4.57×10^{-5}	1.57×10^{-6}

(continued)

Table C-4 (cont)

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc =					
				0.0	0.5	1.0	1.5	2.0	2.5
3.74 x 10^{1}	1.82 x 10^{3}	3.60 x 10^{3}	7.42	1.80 x 10^{-2}	1.23 x 10^{-2}	4.01 x 10^{-3}	6.15 x 10^{-4}	4.45 x 10^{-5}	1.52 x 10^{-6}
4.56 x 10^{1}	1.82 x 10^{3}	3.60 x 10^{3}	8.39	1.70 x 10^{-2}	1.17 x 10^{-2}	3.78 x 10^{-3}	5.80 x 10^{-4}	4.20 x 10^{-5}	1.43 x 10^{-6}
5.57 x 10^{1}	1.83 x 10^{3}	3.60 x 10^{3}	9.47	1.56 x 10^{-2}	1.08 x 10^{-2}	3.49 x 10^{-3}	5.35 x 10^{-4}	3.88 x 10^{-5}	1.33 x 10^{-6}
6.81 x 10^{1}	1.83 x 10^{3}	3.60 x 10^{3}	1.07 x 10^{1}	1.42 x 10^{-2}	9.77 x 10^{-3}	3.17 x 10^{-3}	4.86 x 10^{-4}	3.52 x 10^{-5}	1.20 x 10^{-6}
8.32 x 10^{1}	1.84 x 10^{3}	3.60 x 10^{3}	1.20 x 10^{1}	1.28 x 10^{-2}	8.77 x 10^{-3}	2.85 x 10^{-3}	4.37 x 10^{-4}	3.16 x 10^{-5}	1.08 x 10^{-6}
1.02 x 10^{2}	1.85 x 10^{3}	3.60 x 10^{3}	1.34 x 10^{1}	1.14 x 10^{-2}	7.81 x 10^{-3}	2.53 x 10^{-3}	3.89 x 10^{-4}	2.82 x 10^{-5}	9.63 x 10^{-7}
1.25 x 10^{2}	1.86 x 10^{3}	3.60 x 10^{3}	1.51 x 10^{1}	1.00 x 10^{-2}	6.90 x 10^{-3}	2.24 x 10^{-3}	3.43 x 10^{-4}	2.49 x 10^{-5}	8.50 x 10^{-7}
1.52 x 10^{2}	1.87 x 10^{3}	3.60 x 10^{3}	1.70 x 10^{1}	8.80 x 10^{-3}	6.05 x 10^{-3}	1.96 x 10^{-3}	3.01 x 10^{-4}	2.18 x 10^{-5}	7.44 x 10^{-7}
1.87 x 10^{2}	1.89 x 10^{3}	3.60 x 10^{3}	1.92 x 10^{1}	7.68 x 10^{-3}	5.28 x 10^{-3}	1.71 x 10^{-3}	2.63 x 10^{-4}	1.90 x 10^{-5}	6.51 x 10^{-7}
2.29 x 10^{2}	1.90 x 10^{3}	3.60 x 10^{3}	2.18 x 10^{1}	6.65 x 10^{-3}	4.57 x 10^{-3}	1.48 x 10^{-3}	2.27 x 10^{-4}	1.65 x 10^{-5}	5.61 x 10^{-7}
2.80 x 10^{2}	1.93 x 10^{3}	3.60 x 10^{3}	2.49 x 10^{1}	5.71 x 10^{-3}	3.92 x 10^{-3}	1.27 x 10^{-3}	1.95 x 10^{-4}	1.41 x 10^{-5}	4.84 x 10^{-7}
3.43 x 10^{2}	1.96 x 10^{3}	3.60 x 10^{3}	2.87 x 10^{1}	4.85 x 10^{-3}	3.33 x 10^{-3}	1.08 x 10^{-3}	1.66 x 10^{-4}	1.20 x 10^{-5}	4.10 x 10^{-7}
4.20 x 10^{2}	1.99 x 10^{3}	3.60 x 10^{3}	3.33 x 10^{1}	4.07 x 10^{-3}	2.80 x 10^{-3}	9.09 x 10^{-4}	1.39 x 10^{-4}	1.01 x 10^{-5}	3.44 x 10^{-7}
5.15 x 10^{2}	2.04 x 10^{3}	3.60 x 10^{3}	3.91 x 10^{1}	3.38 x 10^{-3}	2.32 x 10^{-3}	7.55 x 10^{-4}	1.16 x 10^{-4}	8.38 x 10^{-6}	2.89 x 10^{-7}
6.30 x 10^{2}	2.09 x 10^{3}	3.60 x 10^{3}	4.65 x 10^{1}	2.77 x 10^{-3}	1.91 x 10^{-3}	6.19 x 10^{-4}	9.49 x 10^{-5}	6.87 x 10^{-6}	2.36 x 10^{-7}
7.73 x 10^{2}	2.15 x 10^{3}	3.60 x 10^{3}	5.58 x 10^{1}	2.25 x 10^{-3}	1.54 x 10^{-3}	5.01 x 10^{-4}	7.68 x 10^{-5}	5.57 x 10^{-6}	1.90 x 10^{-7}
9.47 x 10^{2}	2.23 x 10^{3}	3.60 x 10^{3}	6.75 x 10^{1}	1.80 x 10^{-3}	1.24 x 10^{-3}	4.02 x 10^{-4}	6.16 x 10^{-5}	4.46 x 10^{-6}	1.49 x 10^{-7}
1.16 x 10^{3}	2.33 x 10^{3}	3.60 x 10^{3}	8.23 x 10^{1}	1.43 x 10^{-3}	9.82 x 10^{-4}	3.19 x 10^{-4}	4.89 x 10^{-5}	3.54 x 10^{-6}	1.22 x 10^{-7}
1.42 x 10^{3}	2.45 x 10^{3}	3.60 x 10^{3}	1.01 x 10^{2}	1.12 x 10^{-3}	7.73 x 10^{-4}	2.51 x 10^{-4}	3.85 x 10^{-5}	2.79 x 10^{-6}	9.64 x 10^{-8}
1.74 x 10^{3}	2.60 x 10^{3}	3.60 x 10^{3}	1.24 x 10^{2}	8.81 x 10^{-4}	6.05 x 10^{-4}	1.96 x 10^{-4}	3.01 x 10^{-5}	2.18 x 10^{-6}	7.55 x 10^{-8}
2.13 x 10^{3}	2.78 x 10^{3}	3.60 x 10^{3}	1.52 x 10^{2}	6.86 x 10^{-4}	4.71 x 10^{-4}	1.53 x 10^{-4}	2.35 x 10^{-5}	1.70 x 10^{-6}	5.91 x 10^{-8}
2.62 x 10^{3}	3.00 x 10^{3}	3.60 x 10^{3}	1.86 x 10^{2}	5.31 x 10^{-4}	3.65 x 10^{-4}	1.19 x 10^{-4}	1.82 x 10^{-5}	1.32 x 10^{-6}	4.37 x 10^{-8}
3.21 x 10^{3}	3.27 x 10^{3}	3.60 x 10^{3}	2.28 x 10^{2}	4.08 x 10^{-4}	2.81 x 10^{-4}	9.11 x 10^{-5}	1.40 x 10^{-5}	1.01 x 10^{-6}	3.52 x 10^{-8}
3.93 x 10^{3}	3.60 x 10^{3}	3.60 x 10^{3}	2.77 x 10^{2}	3.09 x 10^{-4}	2.13 x 10^{-4}	6.90 x 10^{-5}	1.06 x 10^{-5}	7.65 x 10^{-7}	2.70 x 10^{-8}
4.82 x 10^{3}	4.10 x 10^{3}	3.87 x 10^{3}	3.40 x 10^{2}	2.05 x 10^{-4}	1.41 x 10^{-4}	4.58 x 10^{-5}	7.02 x 10^{-6}	5.10 x 10^{-7}	1.76 x 10^{-8}
5.94 x 10^{3}	4.70 x 10^{3}	4.19 x 10^{3}	4.14 x 10^{2}	1.39 x 10^{-4}	9.57 x 10^{-5}	3.11 x 10^{-5}	4.77 x 10^{-6}	3.46 x 10^{-7}	1.09 x 10^{-8}
7.33 x 10^{3}	5.45 x 10^{3}	4.58 x 10^{3}	5.02 x 10^{2}	9.06 x 10^{-5}	6.22 x 10^{-5}	2.02 x 10^{-5}	3.10 x 10^{-6}	2.24 x 10^{-7}	8.61 x 10^{-9}
9.07 x 10^{3}	6.36 x 10^{3}	5.03 x 10^{3}	6.05 x 10^{2}	5.27 x 10^{-5}	3.62 x 10^{-5}	1.17 x 10^{-5}	1.80 x 10^{-6}	1.31 x 10^{-7}	4.02 x 10^{-9}
1.13 x 10^{4}	7.47 x 10^{3}	5.57 x 10^{3}	7.23 x 10^{2}	2.55 x 10^{-5}	1.75 x 10^{-5}	5.70 x 10^{-6}	8.73 x 10^{-7}	6.35 x 10^{-8}	2.33 x 10^{-9}
1.40 x 10^{4}	8.84 x 10^{3}	6.11 x 10^{3}	8.62 x 10^{2}	1.46 x 10^{-5}	1.00 x 10^{-5}	3.26 x 10^{-6}	5.00 x 10^{-7}	3.61 x 10^{-8}	1.59 x 10^{-9}
1.75 x 10^{4}	1.05 x 10^{4}	6.67 x 10^{3}	1.02 x 10^{3}	1.04 x 10^{-5}	7.13 x 10^{-6}	2.31 x 10^{-6}	3.55 x 10^{-7}	2.58 x 10^{-8}	6.70 x 10^{-10}
2.20 x 10^{4}	1.26 x 10^{4}	7.49 x 10^{3}	1.21 x 10^{3}	5.98 x 10^{-6}	4.11 x 10^{-6}	1.33 x 10^{-6}	2.05 x 10^{-7}	1.48 x 10^{-8}	4.55 x 10^{-10}

Table C-5. Input for DEGADIS Simulation of a Vertical Wellhead Release

Value			Line Number
Release from a			1
Well Head:			2
Verticle Jet Simulation			3
			4
1.5	10.		5
0.1			6
1	6	0.	7
273.	1.	75.	8
273.			9
CPD			10
25.2			11
3,600.			12
273.			13
4.7×10^{-4}	1.0×10^{-4}	1.6	14
0	1,500.	0.0	15
0			16
7.69			17
5.0	0.0192		18
3,600.			19
50.			20

Line 18 contains the height of release (5 m) and the effective diameter (0.0192 m)

Line 19 is the duration of release, 3,600 s.

Line 20 is the distance between points at which DEGADIS calculates the output.

DEGADIS Output

A partial DEGADIS output is given in Table C-6. The first column gives the distance downwind and the second gives the elevation. As can be seen, the plume rises substantially because of its initial momentum. The third column gives the concentration of the released gas as a mole fraction, the fourth column gives the concentration in kg/m^3 and the fifth column gives the density in kg/m^3. As can be seen, the density rapidly approaches that of the surrounding air, 1.29 kg/m^3. The fifth column gives the temperature of the plume, which remains constant at 273K because the released plume and the air both have that temperature. The sixth column gives the plume horizontal standard deviation, σ y, and the seventh column gives the vertical standard deviation, σ z (the concentration across the plume is approximated by a Gaussian distribution in DEGADIS). As can be seen, at a height of 1.60 m, the predicted width of the plume (the distance across the wind to the upper or lower Levels of Concern, LC$_{01}$ and ERPG-2) is zero so that LOCs are not predicted to be seen at ground level. This is a typical result for vertical jets of sour gas in stable weather conditions, whether DEGADIS, SLAB, or SAPLUME is used.

SAMPLE SAPLUME CALCULATIONS

SAPLUME Input

Table C-7 contains the input for the model SAPLUME corresponding to Table C-3, which contains the SLAB input for a horizontal release with composition D. The first few lines of input begin with four asterisks and are title cards, followed by a blank which tells the code that the titles have ended. Each subsequent line or group of lines begins with a keyword, followed by numbers in exponential notation to three significant figures.

"SITE" tells SAPLUME that there is a site with one radius and one sector (this is the default when the model is not considering a real site). The following line gives the one radius, arbitrarily set at 10,000 m, with one person arbitrarily set at that point (in the mode of operation chosen for the current problem, the model ignores these numbers).

"WEATHER" specifies that one weather condition only, category F, is being considered (because the 1.000 that follows WEATHER begins at space 61. For E the space would be 51, for D, 41 and so forth. The model can consider all six weather categories at once with up to four velocity subdivisions in each.) In this case, there is one velocity subdivision, specified as 1.5 m/s (first line after weather), and the probability that the wind blows into the one sector is unity (second line after weather).

Table C-6. Partial DEGADIS Output - Vertical Jet

Release from a Wellhead Pipeline Vertical Jet Simulation

								At z = 1.60 m				
									Width to mol%:			
Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σy (m)	σx (m)	Mole Fraction	1.00×10^{-2} (m)	4.70×10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
1.000×10^{-30}	5.15	1.00	1.13	1.13	273	1.060×10^{-2}	1.059×10^{-2}	.000	0	0	1.00	5.15
29.5	120.	8.279×10^{-4}	9.314×10^{-4}	1.29	273	12.1	12.0	.000	0	0	8.279×10^{-4}	120.
61.4	142.	5.644×10^{-4}	6.349×10^{-4}	1.29	273	16.0	15.6	.000	0	0	5.644×10^{-4}	142.
99.6	157.	4.254×10^{-4}	4.786×10^{-4}	1.29	273	19.2	18.4	.000	0	0	4.254×10^{-4}	157.
142.	169.	3.425×10^{-4}	3.853×10^{-4}	1.29	273	22.0	20.6	.000	0	0	3.425×10^{-4}	169.
191.	180.	2.832×10^{-4}	3.186×10^{-4}	1.29	273	24.6	22.4	.000	0	0	2.832×10^{-4}	180.
240.	188.	2.432×10^{-4}	2.736×10^{-4}	1.29	273	27.0	23.9	.000	0	0	2.432×10^{-4}	188.
289.	196.	2.140×10^{-4}	2.408×10^{-4}	1.29	273	29.2	25.2	.000	0	0	2.140×10^{-4}	196.
339.	202.	1.915×10^{-4}	2.155×10^{-4}	1.29	273	31.4	26.3	.000	0	0	1.915×10^{-4}	202.
389.	207.	1.736×10^{-4}	1.953×10^{-4}	1.29	273	33.4	27.2	.000	0	0	1.736×10^{-4}	207.
438.	212.	1.588×10^{-4}	1.786×10^{-4}	1.29	273	35.5	28.1	.000	0	0	1.588×10^{-4}	212.
488.	217.	1.464×10^{-4}	1.647×10^{-4}	1.29	273	37.5	28.8	.000	0	0	1.464×10^{-4}	217.
538.	221.	1.358×10^{-4}	1.528×10^{-4}	1.29	273	39.4	29.5	.000	0	0	1.358×10^{-4}	221.
588.	225.	1.267×10^{-4}	1.425×10^{-4}	1.29	273	41.4	30.1	.000	0	0	1.267×10^{-4}	225.
638.	228.	1.187×10^{-4}	1.335×10^{-4}	1.29	273	43.4	30.7	.000	0	0	1.187×10^{-4}	228.
688.	231.	1.116×10^{-4}	1.255×10^{-4}	1.29	273	45.3	31.2	.000	0	0	1.116×10^{-4}	231.
738.	234.	1.053×10^{-4}	1.185×10^{-4}	1.29	273	47.2	31.7	.000	0	0	1.053×10^{-4}	234.
787.	237.	9.965×10^{-5}	1.121×10^{-4}	1.29	273	49.2	32.2	.000	0	0	9.965×10^{-5}	237.
837.	240.	9.457×10^{-5}	1.064×10^{-4}	1.29	273	51.1	32.6	.000	0	0	9.457×10^{-5}	240.
887.	242.	8.995×10^{-5}	1.012×10^{-4}	1.29	273	53.1	33.0	.000	0	0	8.995×10^{-5}	242.
937.	245.	8.575×10^{-5}	9.647×10^{-5}	1.29	273	55.0	33.4	.000	0	0	8.575×10^{-5}	245.
987.	247.	8.190×10^{-5}	9.213×10^{-5}	1.29	273	56.9	33.8	.000	0	0	8.190×10^{-5}	247.
1.037×10^{3}	249.	7.836×10^{-5}	8.816×10^{-5}	1.29	273	58.9	34.2	.000	0	0	7.836×10^{-5}	249.
1.087×10^{3}	251.	7.510×10^{-5}	8.449×10^{-5}	1.29	273	60.8	34.5	.000	0	0	7.510×10^{-5}	251.
1.137×10^{3}	253.	7.208×10^{-5}	8.109×10^{-5}	1.29	273	62.7	34.9	.000	0	0	7.208×10^{-5}	253.
1.187×10^{3}	255.	6.928×10^{-5}	7.794×10^{-5}	1.29	273	64.7	35.2	.000	0	0	6.928×10^{-5}	255.
1.237×10^{3}	257.	6.667×10^{-5}	7.501×10^{-5}	1.29	273	66.6	35.5	.000	0	0	6.667×10^{-5}	257.
1.287×10^{3}	258.	6.424×10^{-5}	7.228×10^{-5}	1.29	273	68.5	35.8	.000	0	0	6.424×10^{-5}	258.
1.337×10^{3}	260.	6.197×10^{-5}	6.972×10^{-5}	1.29	273	70.5	36.1	.000	0	0	6.197×10^{-5}	260.
1.387×10^{3}	262.	5.984×10^{-5}	6.733×10^{-5}	1.29	273	72.4	36.3	.000	0	0	5.984×10^{-5}	262.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σ y (m)	σ z (m)	At z = 1.60 m			Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
								Mole Fraction	Width to mol%: 1.00 x 10^{-3} (m)	4.70 x 10^{-2} (m)		
1.437 x 10^3	263.	5.785 x 10^{-5}	6.508 x 10^{-5}	1.29	273	74.3	36.6	.000	0	0	5.785 x 10^{-5}	263.
1.487 x 10^3	265.	5.597 x 10^{-5}	6.296 x 10^{-5}	1.29	273	76.3	36.9	.000	0	0	5.597 x 10^{-5}	265.
1.537 x 10^3	266.	5.420 x 10^{-5}	6.097 x 10^{-5}	1.29	273	78.2	37.1	.000	0	0	5.420 x 10^{-5}	266.
1.587 x 10^3	267.	5.253 x 10^{-5}	5.909 x 10^{-5}	1.29	273	80.2	37.4	.000	0	0	5.253 x 10^{-5}	267.
1.637 x 10^3	269.	5.095 x 10^{-5}	5.732 x 10^{-5}	1.29	273	82.1	37.6	.000	0	0	5.095 x 10^{-5}	269.
1.687 x 10^3	270.	4.945 x 10^{-5}	5.564 x 10^{-5}	1.29	273	84.0	37.9	.000	0	0	4.945 x 10^{-5}	270.
1.737 x 10^3	271.	4.804 x 10^{-5}	5.404 x 10^{-5}	1.29	273	85.9	38.1	.000	0	0	4.804 x 10^{-5}	271.
1.787 x 10^3	273.	4.669 x 10^{-5}	5.253 x 10^{-5}	1.29	273	87.9	38.3	.000	0	0	4.669 x 10^{-5}	273.
1.837 x 10^3	274.	4.542 x 10^{-5}	5.109 x 10^{-5}	1.29	273	89.8	38.6	.000	0	0	4.542 x 10^{-5}	274.
1.887 x 10^3	275.	4.420 x 10^{-5}	4.973 x 10^{-5}	1.29	273	91.7	38.8	.000	0	0	4.420 x 10^{-5}	275.
1.937 x 10^3	276.	4.304 x 10^{-5}	4.842 x 10^{-5}	1.29	273	93.7	39.0	.000	0	0	4.304 x 10^{-5}	276.
1.987 x 10^3	277.	4.194 x 10^{-5}	4.718 x 10^{-5}	1.29	273	95.6	39.2	.000	0	0	4.194 x 10^{-5}	277.
2.037 x 10^3	278.	4.089 x 10^{-5}	4.600 x 10^{-5}	1.29	273	97.5	39.5	.000	0	0	4.089 x 10^{-5}	278.
2.087 x 10^3	279.	3.988 x 10^{-5}	4.487 x 10^{-5}	1.29	273	99.4	39.7	.000	0	0	3.988 x 10^{-5}	279.
2.137 x 10^3	280.	3.892 x 10^{-5}	4.378 x 10^{-5}	1.29	273	101.	39.9	.000	0	0	3.892 x 10^{-5}	280.
2.187 x 10^3	281.	3.800 x 10^{-5}	4.275 x 10^{-5}	1.29	273	103.	40.1	.000	0	0	3.800 x 10^{-5}	281.
2.237 x 10^3	282.	3.711 x 10^{-5}	4.175 x 10^{-5}	1.29	273	105.	40.3	.000	0	0	3.711 x 10^{-5}	282.
2.287 x 10^3	283.	3.627 x 10^{-5}	4.080 x 10^{-5}	1.29	273	107.	40.5	.000	0	0	3.627 x 10^{-5}	283.
2.337 x 10^3	284.	3.546 x 10^{-5}	3.989 x 10^{-5}	1.29	273	109.	40.7	.000	0	0	3.546 x 10^{-5}	284.
2.387 x 10^3	285.	3.468 x 10^{-5}	3.901 x 10^{-5}	1.29	273	111.	40.9	.000	0	0	3.468 x 10^{-5}	285.
2.437 x 10^3	286.	3.393 x 10^{-5}	3.817 x 10^{-5}	1.29	273	113.	41.1	.000	0	0	3.393 x 10^{-5}	286.
2.487 x 10^3	286.	3.321 x 10^{-5}	3.736 x 10^{-5}	1.29	273	115.	41.2	.000	0	0	3.321 x 10^{-5}	286.
2.537 x 10^3	287.	3.252 x 10^{-5}	3.658 x 10^{-5}	1.29	273	117.	41.4	.000	0	0	3.252 x 10^{-5}	287.
2.587 x 10^3	288.	3.185 x 10^{-5}	3.583 x 10^{-5}	1.29	273	119.	41.6	.000	0	0	3.185 x 10^{-5}	288.
2.637 x 10^3	289.	3.121 x 10^{-5}	3.511 x 10^{-5}	1.29	273	120.	41.8	.000	0	0	3.121 x 10^{-5}	289.
2.687 x 10^3	290.	3.059 x 10^{-5}	3.441 x 10^{-5}	1.29	273	122.	42.0	.000	0	0	3.059 x 10^{-5}	290.
2.737 x 10^3	290.	2.999 x 10^{-5}	3.374 x 10^{-5}	1.29	273	124.	42.2	.000	0	0	2.999 x 10^{-5}	290.
2.787 x 10^3	291.	2.941 x 10^{-5}	3.309 x 10^{-5}	1.29	273	126.	42.3	.000	0	0	2.941 x 10^{-5}	291.
2.837 x 10^3	292.	2.885 x 10^{-5}	3.246 x 10^{-5}	1.29	273	128.	42.5	.000	0	0	2.885 x 10^{-5}	292.
2.887 x 10^3	293.	2.831 x 10^{-5}	3.185 x 10^{-5}	1.29	273	130.	42.7	.000	0	0	2.831 x 10^{-5}	293.
2.937 x 10^3	293.	2.779 x 10^{-5}	3.127 x 10^{-5}	1.29	273	132.	42.9	.000	0	0	2.779 x 10^{-5}	293.
2.987 x 10^3	294.	2.729 x 10^{-5}	3.070 x 10^{-5}	1.29	273	134.	43.0	.000	0	0	2.729 x 10^{-5}	294.
3.037 x 10^3	295.	2.680 x 10^{-5}	3.015 x 10^{-5}	1.29	273	136.	43.2	.000	0	0	2.680 x 10^{-5}	295.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σy (m)	σz (m)	At z = 1.60 m			Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
								Mole Fraction	Width to mol%: 1.00×10^{-2} (m)	Width to mol%: 4.70×10^{-2} (m)		
3.087×10^3	295.	2.633×10^{-5}	2.962×10^{-5}	1.29	273	138.	43.4	.000	0	0	2.633×10^{-5}	295.
3.137×10^3	296.	2.588×10^{-5}	2.911×10^{-5}	1.29	273	139.	43.5	.000	0	0	2.588×10^{-5}	296.
3.187×10^3	297.	2.543×10^{-5}	2.861×10^{-5}	1.29	273	141.	43.7	.000	0	0	2.543×10^{-5}	297.
3.237×10^3	297.	2.500×10^{-5}	2.813×10^{-5}	1.29	273	143.	43.9	.000	0	0	2.500×10^{-5}	297.
3.262×10^3	297.	2.479×10^{-5}	2.789×10^{-5}	1.29	273	144.	43.9	.000	0	0	2.479×10^{-5}	297.

The entries on the "PROPERTIES" line are as follows: the ambient temperature is 273K at which temperature the density of air is 1.29 kg/m^3 and its specific heat at constant pressure is 990 J/kg/K. At a temperature of 273K, the density of the released gas is 1.141 kg/m^3 and the specific heat at constant pressure is 1,500 J/kg/K.

The entries on the "SOURCE" line are as follows: the rate of release is 7.69 kg/m^3 at a temperature of 273K. The amount of air initially entrained with the source is zero. The angle of release is zero radians (horizontal). The height of release is 5 m. The initial momentum flux is 2,540 kg m s^{-2} and is the product of the rate of release and the exit velocity (the speed of sound is approximately 330 m/s).

The "INTERVAL" line specifies that SAPLUME calculations start at a downwind distance x of 0.1 m and that calculations are performed at a uniform spacing of 0.15 in $\log_{10}(x)$.

On the "ROUG" line, the surface roughness length is 0.1 m and the windspeed is measured at a height of 10 m.

The "HAZARD" line specifies two levels of concern. As explained above in the discussion of the SLAB results, these are the LC_{01} of 470 ppm (approximately 5.32×10^{-4} kg/m^3) and the ERPG-2 of 100 ppm (1.141×10^{-4} kg/m^3).

"VGRAD" informs SAPLUME that it should consider the velocity gradient and the temperature gradient in the atmosphere. SAPLUME uses standard textbook formulae for these gradients. If the first entry after VGRAD were zero, velocity would be constant as a function of height. Similarly, if the second entry after VGRAD were zero, the temperature of the atmosphere would remain constant as height increases.

A value of 3 after "NEUT" specifies one of three parametrizations for the standard deviations in the Gaussian model once the released material has evolved out of the jet phase. NEUT =3 corresponds to a parameterization that is appropriate for a rural site. "DUR" specifies that the duration of release is one hour.

Finally, the repetition of "END" terminates the run of SAPLUME.

SAPLUME Output

A partial SAPLUME output corresponding to the input in Table C-7 is given in Table C-8. This table indicates that, for hazard level 1 (i.e., the LC_{01} of 470 ppm discussed above) the plume touches down at a downwind distance of approximately 63 m and extends to about 3 km, covering an area of about 10^5 m^2 (one tenth of a square kilometer). The table of pairs of values of downwind distance, x, and width can be coupled to a plotting routine to give contours of constant concentration. Similarly, hazard level 2 (the ERPG-2 of 100 ppm)

Table C-7. Input for SAPLUME Runs

****	EPA Hydrogen Sulfide Runs					
****	January 1993					
****	No Protective Measures					
****	Composition D - 30% H_2S at Wellhead					
****	2x10^{7} SCFD:					
****	Horizontal Release					
****	H_2S Release Rate - 3.073 kg/s					
****	Total Mixture Release Rate - 7.69 kg/s					
****	Hazard Level - ERPG-2 (100 ppm) and					
****	LC_{01} (470 ppm) Both Adjusted for Stream Composition					
****	Category F Weather, Windspeed 1.5 m/s					
SITE	1.000	1.000				
$1.000\text{x}10^{4}$						
1.000						
WEATHER	1.000					
1.500						
$2.500\text{x}10^{-1}$						
PROP	$2.730\text{x}10^{2}$	1.290	$9.900\text{x}10^{2}$	$2.730\text{x}10^{2}$	1.141	$1.500\text{x}10^{3}$
SOURCE	7.690	$2.730\text{x}10^{2}$	0.000	0.000	5.000	$2.540\text{x}10^{3}$
INTERVAL	$1.000\text{x}10^{-1}$	$1.5000\text{x}10^{-1}$				
ROUG	$1.0000\text{x}10^{-1}$	$1.000\text{x}10^{1}$				
HAZARD	2.000					
$5.320\text{x}10^{-4}$	$1.141\text{x}10^{-4}$					
VGRAD	1.000	1.000				
NEUT	3.000					
DUR	1.000					
END						
END						

Table C-8. Partial SAPLUME Output for Horizontal Plume

FOR HAZARD LEVEL 1, WINDSPEED 1.500 m/s AND CATEGORY 6

THE HAZARDOUS CLOUD EXTENDS FROM 6.327x10^{1} TO 3.126x10^{3} METERS DOWNWIND AND HAS AN AREA OF 1.129x10^{5} m^{2}

CLOUD BOUNDARIES

X[a] (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)
0.000	0.000	1.000x10^{-1}	0.000	1.162x10^{-1}	0.000	1.350x10^{-1}	0.000	1.568x10^{-1}	0.000
1.822x10^{-1}	0.000	2.117x10^{-1}	0.000	2.460x10^{-1}	0.000	2.858x10^{-1}	0.000	3.320x10^{-1}	0.000
3.857x10^{-1}	0.000	4.482x10^{-1}	0.000	5.207x10^{-1}	0.000	6.050x10^{-1}	0.000	7.029x10^{-1}	0.000
8.166x10^{-1}	0.000	9.488x10^{-1}	0.000	1.102	0.000	1.281	0.000	1.488	0.000
1.729	0.000	2.009	0.000	2.334	0.000	2.711	0.000	3.150	0.000
3.660	0.000	4.252	0.000	4.940	0.000	5.740	0.000	6.669	0.000
7.748	0.000	9.002	0.000	1.046x10^{1}	0.000	1.215x10^{1}	0.000	1.412x10^{1}	0.000
1.640x10^{1}	0.000	1.906x10^{1}	0.000	2.214x10^{1}	0.000	2.572x10^{1}	0.000	2.989x10^{1}	0.000
3.472x10^{1}	0.000	4.034x10^{1}	0.000	4.687x10^{1}	0.000	5.446x10^{1}	0.000	6.327x10^{1}	5.555
7.351x10^{1}	2.627	8.540x10^{1}	2.739	9.922x10^{1}	2.955	1.153x10^{2}	3.294	1.339x10^{2}	3.768
1.556x10^{2}	4.385	1.808x10^{2}	5.149	2.101x10^{2}	6.066	2.441x10^{2}	7.143	2.835x10^{2}	8.388
3.294x10^{2}	9.811	3.827x10^{2}	1.142x10^{1}	4.447x10^{2}	1.324x10^{1}	5.167x10^{2}	1.527x10^{1}	6.003x10^{2}	1.701x10^{1}
6.974x10^{2}	1.856x10^{1}	8.103x10^{2}	2.005x10^{1}	9.414x10^{2}	2.140x10^{1}	1.094x10^{3}	2.257x10^{1}	1.271x10^{3}	2.345x10^{1}
1.476x10^{3}	2.393x10^{1}	1.715x10^{3}	2.384x10^{1}	1.993x10^{3}	2.295x10^{1}	2.315x10^{3}	2.082x10^{1}	2.690x10^{3}	1.653x10^{1}
3.126x10^{3}	5.139								

[a] x = Downwind distance.

extends from about 60 m to about 12 km downwind, covering an area of approximately 10^6 m^2.

The above results are close to those predicted by SLAB. The higher result is about 50% larger than that predicted by SLAB. However, the difference is within the range of uncertainties expected for these dispersion models. As noted above, the neglect of dry deposition means that the predictions are likely to be conservative.

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16. ABSTRACT

Under section 112(n)(5) of the Clean Air Act Amendments of 1990, the EPA is required to submit this report which assesses the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natual gas. This assessment is designed to build upon work done under section 8002(m) of the Solid Waste Disposal Act and to reflect consultation with the States. The report includes a review of existing State and industry control standards, techniques, and enforcement and includes recommendations for control of hydrogen sulfide emissions from these sources.

The Office of Air Quality Planning and Standards and the Office of Solid Waste and Emergency Response completed this report on a joint effort. This report provides the information currently available on each of the elements listed above.

17. KEY WORDS AND DOCUMENT ANALYSIS

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Hydrogen Sulfide, Oil and Gas, and People's Health

By

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Submitted in partial satisfaction of the requirements for the degree of

Master's of Science

May 2006

Energy and Resources Group
University of California, Berkeley

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Tables

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1. Introduction

This paper documents impacts on human health caused by exposure to hydrogen sulfide (H_2S) associated with oil and natural gas development. I begin with a brief background on hydrogen sulfide, its presence in oil and natural gas, and possible emission sources from various oil and gas operations. I then present a review of literature[1] from available public health, epidemiology, and industrial health publications, as well as of sources from regulatory and environmental agencies, that addresses human health impacts from exposure to H_2S. The Literature Review section first covers studies of health effects from acute exposure to relatively high concentrations of H_2S. I then review the literature documenting human health effects from chronic exposure to lower ambient H_2S levels. Both kinds of exposure – acute and chronic – can be expected to occur near oil and gas operations. From the available sources, I construct a table of human health effects associated with different levels of hydrogen sulfide and different lengths of exposure. Reviewing studies on the effects of H_2S exposure on laboratory animals is beyond the scope of this study.

Next, I present current federal and state regulations and recommendations pertaining to exposure to hydrogen sulfide. Many recommendations established to protect human health are based on crude exposure estimates or on extrapolation from animal studies. The federal government does not regulate ambient H_2S levels, but many states do. Three states conduct routine monitoring of ambient H_2S levels, and several others have monitored H_2S as part of specific projects. I present the available monitoring data, as well as anecdotal evidence about H_2S emissions and human health concerns that I obtained from conversations with staff at state environmental agencies.

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[1] I searched on-line catalogs including Web of Science and Environmental Sciences and Pollution Management, and tracked down relevant references listed within each article.

The final component of my research consists of informal interviews with people living near oil and gas operations who have been, or believe they have been, exposed to hydrogen sulfide and believe they are experiencing adverse heath effects due to exposure. Enough evidence emerges from literature searches and reviews, environmental health professionals, available monitoring data, and personal stories to warrant more research. Although the evidence is patchy, the potential for health risks is real and the stakes are high. More monitoring and regulation are required to adequately protect human health.

2. Hydrogen Sulfide in the Environment

Approximately 90 percent of the sources that emit hydrogen sulfide into the air are natural.[2] Hydrogen sulfide is released into the air as a product of the decomposition of dead plant and animal material,[3] especially when this occurs in wet conditions with limited oxygen, such as in swamps. Hot springs, volcanoes, and other geothermal sources also emit H_2S.

Anthropogenic releases of H_2S into the air result from industrial processes, primarily from the extraction and refining of oil and natural gas and from paper and pulp manufacturing,[4] but the gas is also present at sewage treatment plants, manure-handling plants, tanneries, and coke oven plants.[5]

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[2] EPA, "Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas." EPA-453/R-93-045, October 1993. " p.III-4.

[3] Decomposition of dead organic matter (DOM) by fungi, actinomycetes, and bacteria releases hydrogen sulfide from sulfur-containing proteins and from the direct reduction of sulfate (SO4+).

[4] New York State Department of Health: available at http://www.health.state.ny.us/nysdoh/environ/btsa/sulfide.htm

[5] "Public Health Statement for Hydrogen Sulfide," Agency for Toxic Substances and Disease, September 2004. Available at http://www.atsdr.cdc.gov/toxprofiles/tp114-c1.pdf

3. Hydrogen Sulfide and Oil and Gas

Hydrogen sulfide is a naturally occurring component of crude oil and natural gas. Petroleum oil and natural gas are the products of thermal conversion of decayed organic matter (called kerogen) that is trapped in sedimentary rocks. High-sulfur kerogens release hydrogen sulfide during decomposition, and this H_2S stays trapped in the oil and gas deposits.[6]

Methane (CH_4) is the predominant component of natural gas, comprising 70 to 90 percent, while other gaseous hydrocarbons, butane (C_4H_{10}), propane (C_3H_8), and ethane (C_2H_6), account for up to 20 percent. Contaminants present in natural gas, which have to be removed at natural gas processing facilities, include water vapor, sand, oxygen, carbon dioxide, nitrogen, rare gases such as helium and neon, and hydrogen sulfide.[7] In fact, hydrogen sulfide is the predominant impurity in natural gas.[8] The Environmental Protection Agency (EPA) classifies natural gas as *sour* when H_2S is present "in amounts greater than 5.7 milligrams per normal cubic meters (mg/Nm^3) (0.25 grains per 100 standard cubic feet)."[9]

Sour gas is routinely 'sweetened' at processing facilities called desulfurization plants. Ninety five percent of the gas sweetening process involves removing the H_2S by absorption in an amine solution, while other methods include carbonate processes, solid bed absorbents, and physical absorption.[10]

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[6] EPA "Report to Congress on Hydrogen Sulfide Emissions", p.II-1.

[7] *Oil and Gas at Your Door? A landowner's guide to oil and gas development*. OGAP 2005. p.I-2.

[8] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.II-i.

[9] Environmental Protection Agency, AP 42, Fifth Edition, Volume I, Chapter 5: The Petroleum Industry, available at http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s03.pdf

[10] EPA, "Petroleum Industry." P.5.3-1. For details on these and other technologies for 'sweetening' sour gas, see "Crystasulf Process for Desulfurizing Ultra-deep Natural Gas Near the Wellhead," presented at *Natural Gas Technologies II Conference and Exhibition,* February 2004. Phoenix, AZ. Ref. No. T04135. pp.5-9.

Between 15 to 25 percent of natural gas in the U.S. may contain hydrogen sulfide,[11] while worldwide, the figure could be as high as 30 percent. The exact number of sour wells in the United States is not known, though natural gas deposits in Arkansas, southeastern New Mexico, western Texas, and north-central Wyoming have been identified as sour.[12] Hydrogen sulfide occurs naturally in the geologic formations in the Rockies, the Midcontinent, Permian Basin, and Michigan and Illinois Basins.[13] As more natural gas development occurs in these areas, it is likely that the number of sour wells will increase, because new drilling is increasingly focused on deep gas formations that tend to be sour.[14] Although exact statistics on sour wells are not available, the EPA concedes that "the potential for routine H_2S emissions [at oil and gas wells] is significant."[15]

The most comprehensive source on the distribution of sour gas is a report prepared by consultants for the Gas Technology Institute, formerly Gas Research Institute, a research, development, and training organization that serves the natural gas industry.[16] This report states that "Regions with the largest percentage of proven reserves with at least 4 ppm hydrogen sulfide are Eastern Gulf of Mexico (89 percent), Overthrust (77 percent), and Permian Basin (46

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[11] Dalrymple, D.A., Skinner, F.D. and Meserole, N.P. 1991. *Investigation of U.S. Natural Gas Reserve Demographics and Gas Treatment Processes.* Topical Report, GRI-91/0019, Section 3.0, pp. 3-1 to 3-13. Gas Research Institute. And Hugman, R.H., Springer, P.S. and Vidas, E.H. *Chemical Composition of Discovered and Undiscovered Natural Gas in the United States: 1993 update*. Topical Report, GRI-93/0456. p. 1-3. Gas Research Institute. As cited in McIntush, K.E., Dalrymple, D.A. and Rueter, C.O. 2001. "New process fills technology gap in removing H2S from gas," *World Oil*, July, 2001.

[12] EPA, "Report to Congress on Hydrogen Sulfide Emissions". p. I-3.

[13] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p. I-3.

[14] Quinlan, M., 1996. "Evaluation of selected emerging sulfur recovery technologies," *GRI Gas Tips*, 3(1):26-35. In McIntush, K.E., Dalrymple, D.A. and Rueter, C.O. 2001. "New process fills technology gap in removing H2S from gas," *World Oil*, July, 2001.

[15] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-35.

[16] Energy and Environmental Analysis, Inc. for Gas Research Institute, "Chemical Composition of Discovered and Undiscovered Natural Gas in the Lower-48 United States," GRI 90/0248. November 1990. (mailed to me by librarian for Gas Technology Institute).

percent)."[17] Figure 1 illustrates the major H_2S prone areas in the United States and identifies the basins.

Figure 1. ***Map of Major H_2S-prone Areas in the Continental United States*[18]**

4. Hydrogen Sulfide Emissions from Oil and Gas Facilities

There has been some investigation of hydrogen sulfide emissions associated with oil and gas development.[19] In the Literature Review section, I summarize several studies that researched H_2S emissions near oil and gas facilities. Several states' environmental departments have monitored H_2S concentrations near oil and gas operations. My conversations with personnel at these agencies confirm that there are H_2S emissions associated with oil and gas activities. I present the evidence from the state studies and my conversations with staff in the State Regulations section. Finally, the interviews I conducted with people living near oil and gas

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[17] Energy and Environmental Analysis, Inc. for Gas Research Institute. pp.2-3.

[18] Energy and Environmental Analysis, Inc. for Gas Research Institute. p.1-13 and p.A-5.

[19] For example, Environmental Protection Agency, "Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas." EPA-453/R-93-045, October 1993. and Tarver, Gary A. and Purnendu K. Dasgupta. "Oil Field Hydrogen Sulfide in Texas: Emission Estimates and Fate." *Environmental Science and Technology*. **31**: (12) 3669-3676. 1997.

sites attest to the presence of H_2S in the ambient air. Detailed narratives of the interviews are in Appendix D.

Oil and gas operations may emit hydrogen sulfide, routinely or accidentally, during the extraction, storage, transport, or processing stage.[20] During of extraction, hydrogen sulfide may be released into the atmosphere at wellheads, pumps, piping, separation devices, oil storage tanks, water storage vessels, and during flaring operations.[21] Flares burn gases that cannot be sold as well as gases at points in the system where operating problems may occur, as a safety measure. Because it cannot be sold, hydrogen sulfide is routinely flared. Sulfur dioxide (SO_2) is the product of combusting hydrogen sulfide, but in the event of incomplete combustion, H_2S may be emitted into the atmosphere.

Based on reviewing the available literature and the records of agencies to which accidental releases of hydrogen sulfide might be reported,[22] the EPA states that well blowouts, line releases, extinguished flares, collection of sour gas in low-lying areas, line leakage, and leakage from idle or abandoned wells are sources of documented accidental releases that have impacted the public, not just workers at of oil and gas extraction sites.[23] Well blowouts are uncontrolled releases from wells, and can occur during drilling, servicing, or production, as a result of a failed 'blowout preventer' during drilling or a failed subsurface safety valve during

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[20] *Schlumberger Oilfield Glossary*, available at http://www.glossary.oilfield.slb.com/default.cfm

[21] EPA "Report on Hydrogen Sulfide Air Emissions," P.II-6. See Section II, pp.3 to 10 for details. A wellhead is the first piece of equipment where the oil leaves the ground. Pumps that extract the oil may leak at the seals. Piping connects the various machinery and storage units at an oil pad. Separation devices separate oil from gas and water, and pipes take the gas to a dehydrator, while other pipes direct water and oil to a heater-treater where the two are separated. The oil is then piped into an oil storage tank, and the water is piped into a produced water storage tank. Wellheads, pipes, and separation devices may leak hydrogen sulfide because of corrosion and embrittlement caused by the reaction of water with metal and H_2S, or due to poor maintenance and poor materials. The heater-treaters may release hydrogen sulfide due to high pressures or pressure changes above design specifications. Oil storage tanks may release hydrogen sulfide as a result of day-night temperature changes, volatilization, and filling operations. Produced water storage vessels may contain hydrogen sulfide dissolved in water that is brought up from the reservoir, or it may be produced by sulfate-reducing bacteria found in water and oil.

[22] State agencies, emergency response organizations, industry officials. EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-36.

[23] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-38.

production.[24] The release from a well blowout can last for an indefinite period.[25] After all economically recoverable oil and gas has been removed, the well needs to be plugged, or sealed. If a well is improperly sealed, hydrogen sulfide may routinely seep into the atmosphere. One study, discussed below, documented precisely this type of hydrogen sulfide emissions in Whaler's Cove, a community in Long Beach, California, where a townhouse development was built on a 1940s oil field. Additionally, hydrogen sulfide may be routinely or accidentally released into the atmosphere at oil refineries and natural gas processing facilities, including desulfurization plants.

Hydrogen sulfide emissions from oil and gas development may pose a significant human health risk, as the studies discussed below reveal. Workers in the oil and gas industry are trained to recognize and respond to high-concentration accidental releases of H_2S. The American Petroleum Institute (API), an oil and gas industry technical organization, publishes recommendations for practices that help prevent hazardous H_2S concentrations from occurring in the workplace.[26] People living near oil and gas development sites may be chronically exposed to much lower, but nonetheless dangerous ambient H_2S levels, as well as to accidental high-concentration releases. A 1993 EPA report on the emissions of hydrogen sulfide from oil and gas extraction acknowledges that because of the proximity of oil and gas wells to areas where people live, the affected population may be large.[27]

Additionally, the "Public Health Statement for Hydrogen Sulfide," a public health advisory summarizing the longer H_2S Toxicological Profile issued by the Centers for Disease Control and Prevention's Agency for Toxic Substances and Disease Registry (ATSDR),

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[24] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-45.

[25] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-49.

[26] API Recommended Practice (RP) 54, *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations* and API RP 49, *Safe Drilling of Wells Containing Hydrogen Sulfide*.

[27] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-65.

acknowledges that "As a member of the general public, you might be exposed to higher-than-normal levels of hydrogen sulfide if you live near a waste water treatment plant, a gas and oil drilling operation, a farm with manure storage or livestock confinement facilities, or a landfill. Exposure from these sources is mainly from breathing air that contains hydrogen sulfide."[28] The ATSDR also reports that higher than normal ambient "levels [of hydrogen sulfide] (often exceeding 90 ppb) have been detected in communities living near natural sources of hydrogen sulfide or near industries releasing hydrogen sulfide."[29]

5. Human Health Effects from Exposure to Hydrogen Sulfide

Human health effects of exposure to hydrogen sulfide, an irritant and an asphyxiant, depend of the concentration of the gas and the length of exposure. Background ambient levels of H_2S in urban areas range from 0.11 to 0.33 ppb, while in undeveloped areas concentrations can be as low as 0.02 to 0.07 ppb.[30] A rotten egg odor characterizes H_2S at low concentrations, and some people can detect the gas by its odor at concentrations as low as 0.5 ppb.[31] About half of the population can smell H_2S at concentrations as low as 8 ppb, and more than 90% can smell it at levels of 50 ppb.[32] Hydrogen sulfide, however, is odorless at concentrations above 150 ppb, because it quickly impairs the olfactory senses.[33] Prolonged exposure to concentrations below

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[28] "Public Health Statement for Hydrogen Sulfide," Agency for Toxic Substances and Disease, September 2004. Available at http://www.atsdr.cdc.gov/toxprofiles/tp114-c1.pdf

[29] ATSRD, Ch2, p.1.

[30] Agency for Toxic Substances and Disease Registry (ATSDR). 2004. Toxicological profile for hydrogen sulfide (*Draft for Public Comment*). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Chapter 2, p.1.

[31] New York State Department of Health: available at http://www.health.state.ny.us/nysdoh/environ/btsa/sulfide.htm

[32] Collins, P. and Lewis, L. 2000. *Hydrogen Sulfide: Evaluation of Current California Air Quality Standard with Respect to Protection of Children.* Prepared for California Air Resources Board and California Office of Environmental Health Hazard Assessment. In: Summary of the toxicity assessment of hydrogen sulfide conducted by the Secretary's Scientific Advisory Board on Toxic Air Pollutants. http://daq.state.nc.us/toxics/studies/H2S

[33] Knight, Laura D., MD, and S. Erin Presnell, MD. 2005. "Death by Sewer Gas: Case Report of a Double Fatality and Review of the Literature." *The American Journal of Forensic Medicine and Pathology*. p.183.

150 ppb can also cause olfactory fatigue.[34] This effect of disabling the sense of smell at levels that pose serious health risks and possibly are life-threatening is one especially insidious aspect of hydrogen sulfide exposure. Odor is not necessarily a reliable warning signal of the presence of H_2S.

Most effects to humans occur from inhalation, though exposure generally also affects the eyes. Because most organ systems are susceptible to its effects, hydrogen sulfide is considered a broad spectrum toxicant.[35] The organs and tissues with exposed mucous membranes (eyes, nose) and with high oxygen demand (lungs, brain) are the main targets of hydrogen sulfide.[36] Hydrogen sulfide acts similarly to hydrogen cyanide, interfering with cytochrome oxidase and with aerobic metabolism.[37] Essentially, hydrogen sulfide blocks cellular respiration, resulting in cellular anoxia, a state in which the cells do not receive oxygen and die. The human body detoxifies hydrogen sulfide by oxidizing it into sulfate or thiosulfate by hemoglobin-bound oxygen in the blood or by liver enzymes.[38] Lethal toxicity occurs when H_2S is present in concentrations high enough to overwhelm the body's detoxification capacity.[39]

At levels up to 100 to 150 ppm, hydrogen sulfide is a tissue irritant, causing keratoconjunctivitis (combined inflammation of the cornea and conjunctiva), respiratory irritation with lacrimation (tears) and coughing.[40] Skin irritation is also a common symptom. Instantaneous loss of consciousness, rapid apnea (slowed or temporarily stopped breathing), and

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[34] Glass, D.C. "A Review of the Health Effects of Hydrogen Sulphide Exposure." *Annals of Occupational Hygiene*. 34:(3) p.323.

[35] Legator, Marvin S., et al.. "Health Effects from Chronic Low-Level Exposure to Hydrogen Sulfide." *Archives of Environmental Health*. **56:** (2) 123-131. March/April 2001. p.124.

[36] Legator, Marvin S., et al.. p.124.

[37] Knight, Laura D., MD, and S. Erin Presnell, MD. 2005. "Death by Sewer Gas: Case Report of a Double Fatality and Review of the Literature." *The American Journal of Forensic Medicine and Pathology*. p.183.

[38] Knight, 2005. p.184.

[39] Knight, 2005. p.184.

[40] Knight, 2005. p.183.

death may result from acute exposure to levels above 1,000 ppm.[41] At these higher levels, hydrogen sulfide is an asphyxiant.

The non-lethal effects can be summarized as *neurological* – consisting of symptoms such as dizziness, vertigo, agitation, confusion, headache, somnolence, tremulousness, nausea, vomiting, convulsions, dilated pupils, and unconsciousness, and *pulmonary* – with symptoms including cough, chest tightness, dyspnea (shortness of breath), cyanosis (turning blue from lack of oxygen), hemoptysis (spitting or coughing up blood), pulmonary edema (fluid in the lungs), and apnea with secondary cardiac effects.[42]

Table 1 lists the health effects associated with H_2S exposures of varying durations. The table reports health effects that toxicological and epidemiological studies have attributed to specific concentrations (or a range of concentrations) of hydrogen sulfide. Table 1 also includes health effects of exposure to known concentrations of H_2S that were self-reported by participants in the studies discussed below.

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[41] Knight, 2005. p.183.
[42] Snyder, Jack W., MD, PhD. et al.. "Occupational Fatality and Persistent Neurological Sequelae After Mass Exposure to Hydrogen Sulfide." *American Journal of Emergency Medicine*. **13**: (2) 199-203. 1995. p.201.

Table 1: Health Effects Associated with Hydrogen Sulfide[43]

Concentration (ppm)	Length of exposure	Effect	Source
0.0057	*Community/chronic*	*Eye and nasal symptoms, coughs, headaches and/or migraines*	*Partti-Pellinen, p.316.*
0.003 – 0.02	Immediate	Detectable odor	EPA Report 1993, p.III-5
0.01	*Community/chronic*	*Neurophysiological abnormalities*	*Legator, p.124.*
0.1 – 1	*Not reported (n.r.)*	*Abnormal balance with closed eyes, delayed verbal recall, impaired color discrimination, decreased grip strength*	*Kilburn, 1999, p.210.*
0.2	n.r.	Detectable odor	Fuller, p.940
0.250 – 0.300	Prolonged	Nuisance due to odor from prolonged exposure	Milby, p.194
1 – 5	*n.r.*	*Abnormal balance with open and closed eyes, delayed verbal recall, impaired color discrimination, decreased grip strength, abnormal simple and choice reaction time, abnormal digit symbol and trailmaking.*	*Kilburn, 1999, p.210*
2 – 8	*Community*	*Malaise, irritability, headaches, insomnia, nausea, throat irritation, shortness of breath, eye irritation, diarrhea, and weight loss*	*EPA Report 1993, p. III-32.*
10	10 minutes	Eye irritation, chemical changes in blood and muscle tissue after 10 minutes	New York State Department of rt
> 30	Prolonged	Fatigue, paralysis of olfaction from prolonged exposure	Snyder, p.200
50	n.r.	Eye and respiratory irritation	Fuller, p.940
50 – 100	Prolonged	Prolonged exposure leads to eye irritation; eye irritation (painful conjunctivitis, sensitivity to light, tearing, clouding of vision) and serious eye injury (permanent scarring of the cornea)	Milby p.194; EPA Report 1993,
150 – 200	n.r.	Olfactory nerve paralysis	EPA Report 1993, p.III-6
200	n.r.	Respiratory and other mucous membrane irritation	Snyder, p.200
250	n.r.	Damage to organs and nervous system; depression of cellular metabolism	EPA Report 1993, p.III-5
250	Prolonged	Possible pulmonary edema from prolonged exposure	Milby p.193
320 – 530	n.r.	Pulmonary edema with risk of death	Kilburn (1999), p.212
500	30 minutes	systemic symptoms after 30 minutes	Fuller, p.940
500 –1000	Immediate	Stimulation of respiratory system, leading to hyperpnoea (rapid breathing); followed by apnea (cessation of breathing)	EPA Report 1993, p.III-5
750	Immediate	Unconsciousness, death	Fuller, p.940
1000	Immediate	Collapse, respiratory paralysis, followed by death	Fuller, p.940, EPA Report 1993 p.
750 – 1000	Immediate	Abrupt physical collapse, with possibility of recovery if exposure is terminated; if not terminated, fatal respiratory paralysis	Milby, p.192
1000 – 2000	n.r.	Immediate collapse with paralysis of respiration	Kilburn (1999), p.212
5000	Immediate	Death	Fuller, p.940

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[43] Italics signify concentrations and health effects in studies that rely on self-reporting of symptoms, usually in questionnaires.

5.1 Literature Review - Acute Exposure

The following studies focused on short-term exposure to relatively high levels of hydrogen sulfide, the kind of scenario that can be expected from an accidental release. There are many documented instances and peer-reviewed studies of serious health effects and deaths from exposure to relatively high concentrations of hydrogen sulfide.

Fuller and Suruda (2000), who reviewed Occupational Safety and Health Administration (OSHA) investigation records from 1984 to 1994, reported 80 deaths in the United States from occupational exposure to hydrogen sulfide, out of a total 18559 occupational death during this period.[44] Twenty-two of the 80 deaths were in the oil and gas industry.[45] These deaths occurred as a result of workers' exposure to accidental releases of hydrogen sulfide in high concentrations. The authors concluded that portable H_2S meters or alarms could have prevented these deaths.[46]

In their 1997 study, Hessel et al. submitted a questionnaire about health effects from hydrogen sulfide exposure to 175 oil and gas workers in Alberta, Canada, a known region of sour gas. Of the 175 workers, one third reported having been exposed to H_2S, and 14 workers (8%) experienced knockdown,[47] a term for the loss of consciousness due to inhaling high concentrations of hydrogen sulfide. The workers who had experienced knockdown exhibited the respiratory symptoms of shortness of breath, wheezing while hurrying or walking up hill, and random wheezing attacks.[48] The investigators found no

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[44] Fuller, Douglas C., MD, MPH, and Anthony J. Suruda, MD, MPH. "Occupationally Related Hydrogen Sulfide Deaths in the United States From 1984 to 1994." *Journal of Occupational and Environmental Medicine*. **42**:(9) 939-942. September 2000. p.940.

[45] Fuller and Suruda, p.941.

[46] Fuller and Suruda, p.942.

[47] Hessel, Patrick A., PhD. et al.. "Lung Health in Relation to Hydrogen Sulfide Exposure in Oil and Gas Workers in Alberta, Canada." *American Journal of Industrial Medicine*. **31**:554-557. 1997., p.555

[48] Hessel, pp.555-556.

"measurable pulmonary health effects as a result of exposure to H_2S that were intense enough to cause symptoms but not intense enough to cause unconsciousness."[49] In other words, the workers who reported initially experiencing symptoms from H_2S exposure did not report exhibiting any lingering respiratory symptoms at the time of the study. However, other kinds of long term effects could exist; indeed, the study itself acknowledged that long term effects of acute short term exposure have not been studied enough, and finds this lack "noteworthy."[50]

Milby and Baselt (1999) relied on a review of literature about hydrogen sulfide poisoning, and state that "A phenomenon referred to as 'knockdown' has been reported in oil field workers and others to describe sudden, brief loss of consciousness followed by immediate full recovery after short-lived exposure to very high concentrations of hydrogen sulfide (e.g., 750-1000 ppm)."[51] However, other studies have contested this claim of full recovery following a knockdown.

Kaye Kilburn, a medical doctor and professor of medicine at the University of Southern California, has devoted a considerable part of his career to studying and reporting on the adverse health effects of hydrogen sulfide. Refuting Milby and Baselt's (1999) finding that full recovery followed unconsciousness, or 'knockdown,' Kilburn states, "In 1989, for the first time, sensitive testing showed that, although survivors who had been unconscious looked all right, brain functions were impaired. Similar impairments were measured in people exposed to amounts below 50 ppm that had not caused unconsciousness. Next, subtle impairments of brain function were measured from

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[49] Hessel, p..556.
[50] Hessel, p.555.
[51] Milby, Thomas H. MD, and Randall C. Baselt, PhD. "Hydrogen Sulfide Poisoning: Clarification of Some Controversial Issues." *American Journal of Industrial Medicine*. **35**: 192-195. 1999. p.192.

exposures to concentrations of less than 5 ppm in air."[52] Kilburn reported examining one oil field worker, Stan, who had experienced 'knockdown' on the job after exposure to 1 percent hydrogen sulfide concentration (or 9,999 ppm as Stan's meter recorded it.) Three years after the incident, while appearing physically healthy, Kilburn's tests of Stan revealed significant brain damage (IQ lowered to 77, though the previous IQ is not reported), severely impaired balance and motor function, and inability to recall stories and visual designs.[53]

Another study by Kilburn (2003)[54] reported long term effects of hydrogen sulfide exposure. Kilburn performed physiologic and psychological measurements on nineteen exposed and 202 unexposed subjects.[55] Ten of the nineteen subjects were exposed at work, including four at oil and gas sites, while the other nine were exposed in their residences, which were near various sources of H_2S.[56] The concentrations to which the subjects were exposed are not known. Exposure times ranged from twenty minutes to nine years, and Kilburn examined the subjects from 1.7 to 22 years after their exposures.[57] The study methods consisted of a questionnaire and a series of neurophysiological and neuropsychological tests. The neurophysiological tests measured simple reaction time, visual two-choice reaction time, balance, color recognition, and hearing, and the neuropsychological tests measured immediate memory recall, mood, and vocabulary.[58] Tension, depression, anger, fatigue, and confusion were all significantly elevated in the

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[52] Kaye H. Kilburn. "Killer Molecules in Natural Gas." Chapter 7 in *Endangered Brains: How Chemicals Threaten Our Future*. Birmingham, AL: Princeton Scientific Publishers Company, Inc. 2004. p.78.
[53] Kilburn, (2004) p.79.
[54] Kilburn, Kaye H. "Effects of Hydrogen Sulfide on Neurobehavioral Function." *Southern Medical Journal*. **96**: (7) 639-646. 2003.
[55] Kilburn, (2003), p.640.
[56] Kilburn, (2003), p.640, see Table 1, p.641.
[57] Kilburn, (2003), p.640.
[58] Kilburn, (2003), pp.640-641.

exposed subjects compared to the control group. In addition, respiratory symptoms were more prevalent among the exposed subjects.[59] Even subjects who did not experience unconsciousness at the time of their exposure exhibited permanent neurobehavioral damage.[60]

The studies mentioned thus far focused on occupational exposure. They document the dangerous properties of hydrogen sulfide, as well as highlight the fact that more research is needed on the long term effects of even short duration exposures. There have been some studies of non-occupational exposure to relatively high H_2S levels. The proximity of oil refineries, gas treatment and processing plants, and oil and gas wells to residences constitutes a likely source of H_2S emissions and potentially poses a risk to people in a non-occupational setting.

Kilburn has studied the health effects of a series of explosions at an oil refinery in Wilmington, California, which occurred in October 1992. The explosions released unknown amounts of hydrogen sulfide into the air, making people ill in Wilmington, Torrance, Carson, Long Beach, and South Los Angeles.[61] Some street monitors recorded H_2S concentrations as high as 24 ppm, and since no one died, Kilburn concluded that concentrations probably did not exceed 200 ppm. Seven thousand people who had been exposed and sickened filed a consolidated lawsuit against the refinery, and a random sample were examined three and a half years after the explosion for court proceedings.[62]

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[59] Kilburn, (2003), p.643.

[60] Kilburn, (2003), p.644.

[61] Kilburn, (2004) p.77.

[62] 400 people were selected to represent the 7000 filing suit, and 120 were selected at random to be examined by a general practitioner. Then, 68 of the 120 were examined using sensitive neurobehavioral tests. Kilburn, (2004) p.81.

Persistent symptoms included impaired balance, delayed recall memory, elevated depression and confusion scores, and abnormally slow reaction times.[63]

As background to their 1987 study, which focused on methods of improving the prediction and management of public health risks associated with the development of sour gas wells, Layton and Cederwall[64] summarized studies of two incidents during which people were exposed to hydrogen sulfide released from gas operations. One occurred in 1950 in Poza Rica, Mexico, where 320 people were hospitalized and 22 died as a result of a major hydrogen sulfide release from a gas purification plant.[65] The second incident, known as the Lodgepole blowout, was a sour gas blowout in Alberta, Canada, in 1982. In this case, the hydrogen sulfide releases lasted for 67 days, and the affected people reported headaches, eye irritation, and various respiratory and gastrointestinal symptoms.[66] In both instances, there were no reliable measurements of H_2S concentrations. In Alberta, maximum reported hourly concentrations were 15 ppm, and concentrations 100 kilometers away from the source were below 100 ppb, but residents there filed over a thousand complaints.[67] This study concluded that the hazard zone for sublethal effects around sour gas wells encompasses from less than 400 meters up to 6500 meters, while lethal exposure to hydrogen sulfide could occur as far as 2000 meters from the source.[68] Among the proposed recommendations for improving public safety is “preemptive land ownership,”[69] an issue which I revisit in the Concluding Remarks section. This study also stressed that

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[63] Kilburn, (2004) p.81.

[64] Layton, David W. and Richard T. Cederwall. 1987. “Predicting and Managing the Health Risks of Sour-Gas Wells.” *Journal of the Air Pollution Control Association.* **37**: 1185-1190.

[65] Layton and Cederwall, 1987. pp.1185-1186.

[66] Layton and Cederwall, 1987. p 1186.

[67] Layton and Cederwall, 1987. p 1186.

[68] Layton and Cederwall, 1987. p 1188.

[69] Layton and Cederwall, 1987. p 1187.

sublethal effects of hydrogen sulfide are not well studied and that the dose-response relationship at lower levels is not well characterized.[70]

5.2 Literature Review - Chronic Exposure

Literature is also available on the human health impacts of chronic exposure to relatively low concentrations of hydrogen sulfide. Generally, chronic exposure to low-level concentrations of hydrogen sulfide is associated with neurological symptoms that include fatigue, loss of appetite, irritability, impaired memory, altered moods, headaches, and dizziness.[71] At persistent concentrations of 0.250 to 0.300 ppm (250 to 300 ppb), the rotten egg odor of H_2S creates a nuisance to communities, and exposure to such concentrations has been documented to affect quality of life by causing headaches, nausea, and sleep disturbances.[72]

Schiffman et al. (1995) evaluated the effect of odors emanating from swine operations on mood.[73] Although the source of odors were swine operations rather than oil and gas sites, the study is relevant because hydrogen sulfide caused the persistent odors, much as is the case near oil refineries and natural gas processing plants. This study concluded that continuously smelling odors is associated with "significantly more tension, more depression, less vigor, more fatigue, and more confusion."[74]

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[70] Layton and Cederwall, 1987. p 1185.

[71] McGavran, Pat. "Literature Review of the Health Effects Associated with the Inhalation of Hydrogen Sulfide." Idaho Department of Environmental Quality, Boise, Idaho. June 19, 2001. p.3.

[72] Milby, 1999, p.194.

[73] Schiffman, Susan S., Elizabeth A. Sattely, et al.. "The Effect of Environmental Odors Emanating From Commercial Swine Operations on the Mood of Nearby Residents." *Brain Research Bulletin*. 37:4 369-375. 1995

[74] Schiffman et al., p.371.

One frequently cited study, by Partti-Pellinen et al. (1996), examined the health effects of chronic, low-level exposure to sulfur compounds, including hydrogen sulfide, near a paper and pulp mill in Finland.[75] They found that the exposed people experienced eye and nasal symptoms, coughs, and headaches or migraines much more frequently than the people in the control group, while acute respiratory infections also occurred more frequently in the study group.[76] Once again, the study acknowledged the lack of data on long term effects of low-dose, chronic exposure, and concluded that, at the very least, the exposure and odor make "everyday life uncomfortable."[77]

Legator et al. (2001) investigated the effects of chronic, low levels of hydrogen sulfide by surveying two exposed communities, Odessa, Texas, and Puna, Hawaii, and comparing the health findings with several control communities.[78] Due to emissions from industrial wastewater, ambient concentrations of H_2S in Odessa, Texas, registered at 335 to 503 ppb over 8 hours, 101 to 201 ppb over 24 hours, with an annual average of 7 to 27 ppb.[79] Puna, Hawaii, is situated in a volcanically active area.[80] There were no reliable measurements of H_2S levels at Puna—they ranged from less than 1 ppb to periodic highs of 200 to 500 ppb. The study relied on a multi-symptom health survey and found various adverse health effects associated with hydrogen sulfide exposure in the study populations. The health symptoms included central nervous system impacts (fatigue, restlessness,

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[75] Partti-Pellinen, Kirsi, Marttila Olli, Vilkka Vesa, et al.. "The South Karelia Air Pollution Study: effects of low-level exposure to malodorous sulfur compounds on symptoms." *Archives of Environmental Health.* **51**. (4) 315-320 1996. The study looked at the main components of total reduced sulfur (TRS) compounds—hydrogen sulfide H_2S, methyl mercaptan, CH_3SH, dimethyl sulfide $[CH_3]_2S$, and dimethyl disulfide $[CH_3]_2S_2$.

[76] Partti-Pellinen et al.. Acute respiratory infections occurred 1.6 times per year in the study group as compared to 1.1 times per year in the control group.

[77] Partti-Pellinen, et al., p.320.

[78] Legator, Marvin S., et al.. "Health Effects from Chronic Low-Level Exposure to Hydrogen Sulfide." *Archives of Environmental Health*. **56:** (2) 123-131. March/April 2001.

[79] Legator, p.124.

[80] Since 1976, Puna is a site of geothermal energy production, and supplies about 30% of Hawaii's electricity. US Department of Energy.

depression, short term memory loss, balance, sleep problems, anxiety, lethargy, headaches, dizziness, tremors), respiratory system impacts (wheezing, shortness of breath, coughing), and various ear, nose, and throat symptoms.[81] This study also concluded with a call for more research:

> The findings in our study, taken together with previously reported data concerning adverse responses to H_2S, strongly mandate the need for continued research on the possible detrimental effects of chronic exposure to the toxic agent. This is of decided public health significance, given the relatively large segment of the population that is regularly exposed to low levels of H_2S.[82]

Kilburn has also studied health impacts from chronic exposure to lower concentrations of hydrogen sulfide. He examined a preacher and eighteen congregation members in Odessa, Texas, who lived downwind from an oil refinery and often smelled the characteristic rotten egg odor of H_2S, occasionally experiencing nausea and vomiting.[83] Kilburn observed impaired balance, delayed verbal recall for stories, and difficulty distinguishing colors among the people he studied in Odessa.[84] Workers and people living downwind of another oil refinery, in Nipoma Mesa near San Luis Obispo, California, also exhibited impaired reaction time, impaired balance, depression, and impaired recall memory.[85]

As a result of poorly plugged wells of an abandoned oil and gas field in Long Beach, California, people living in a community built on this location were exposed to hydrogen sulfide that collected under concrete foundations and crawl spaces of homes,

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[81] Legator, pp.126-129.

[82] Legator, p.130.

[83] Kilburn, (2004) p.79.

[84] Kilburn, (2004) p.80.

[85] Kilburn, (2004) p.80.

and in a low lying area around a communal swimming pool.[86] The H_2S measurements ranged from 0.1 ppm to 1 ppm, with several peaks up to 5 ppm.[87] Kilburn examined 24 people from this community, and recorded abnormal balance with closed eyes, delayed verbal recall, and impaired color discrimination and grip strength, as compared to a control group.[88]

As reported by the EPA,[89] two notable occasions of increased ambient concentrations of hydrogen sulfide occurred in Great Kanawha River Valley, West Virginia, in 1950, and in Terre Haute, Indiana, in 1964. In Terre Haute, ambient H_2S concentrations ranged from 2 to 8 ppm, emanating from a lagoon. In West Virginia, the highest concentration was 293 ppb, but there is no information on other levels. In both cases, symptoms included malaise, irritability, headaches, insomnia, and nausea, while the people exposed in Terre Haute also reported, among other effects, throat irritation, shortness of breath, eye irritation, diarrhea, and weight loss.[90] These incidents provide some evidence of health impacts from chronic exposure to ambient levels of hydrogen sulfide in the range that may be expected to occur near oil and gas sites.

Tarver and Dasgupta (1997) measured hydrogen sulfide concentrations near several oil fields in western Texas.[91] Although the researchers were studying the effects of increased anthropogenic sources of sulfur emissions on the sulfur cycle, the authors nevertheless gathered data that is pertinent to my research. The study found nighttime

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[86] Kilburn, Kaye H. "Evaluating health effects from exposure to hydrogen sulfide: central nervous system dysfunction." *Environmental Epidemiology and Toxicology*. **1**:207-216. 1999. p.208.
[87] Kilburn (1999), p.208.
[88] Kilburn, (1999), p.210.
[89] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-32. For the entire paragraph.
[90] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-32
[91] Tarver, Gary A. and Purnendu K. Dasgupta. "Oil Field Hydrogen Sulfide in Texas: Emission Estimates and Fate." *Environmental Science and Technology*. **31**: (12) 3669-3676. 1997.

maximum H_2S concentrations between 1 and 5 ppb.[92] While this concentration of hydrogen sulfide is only enough to produce an odor, a persistent odor can be a nuisance, and has been associated with increased tension, depression, fatigue, confusion, and decreased vigor.[93]

Some evidence exists on the effects of hydrogen sulfide on the reproductive system. Xu et al. (1998) conducted a retrospective epidemiological study to assess the association between spontaneous abortion and exposure to petrochemicals.[94] By reviewing the plant employment records, which also contain medical information, the researchers identified over 3000 women from the Beijing Yanshan Petrochemical Corporation who had been pregnant. Trained interviewers administered a questionnaire to gather information on the subjects' reproductive history, pregnancy outcomes, employment history, occupational exposure, smoking habits, alcohol consumption, indoor air pollution, diet, and demographic variables.[95] The study found that "exposure to petrochemicals, specifically benzene, gasoline, and hydrogen sulphide is significantly associated with increased frequency of spontaneous abortion."[96] Each chemical was individually found to have a statistically significant effect on the frequency of spontaneous abortion. Although the exposures mainly occurred in maintenance operations or due to accidental leaks and spillages,[97] rather than being chronic low level exposures,[98] this study is nevertheless important for the link it established between hydrogen sulfide

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[92] Tarver and Dasgupta, p.3673.

[93] Schiffman et al. Discussed above on p.18.

[94] Xu, Xiping, Sung-Il Cho, et al.. "Association of petrochemical exposure with spontaneous abortion." *Occupational and Environmental Medicine*. 55: 31-36. 1998.

[95] Xu et al., p.31.

[96] Xu et al., p.34.

[97] Xu et al., p.35.

[98] The study acknowledged that "at lower exposures, the reproductive effects of hydrogen sulphide have not been determined, although it has been shown to enhance the fetal toxicity of carbon disulphide." Xu et al., pp.34-35.

and effects on the reproductive system. According to one personal account recounted below, hydrogen sulfide exposure is associated with spontaneous abortions in cattle as well as other reproductive effects in animals.

Most studies acknowledge that there is a need for more research on the health impacts of chronic exposure to lower concentrations of H_2S. Although the health effects are not well documented,[99] many studies recognize the potential for harm. In 1993, the EPA prepared an in-depth report on hydrogen sulfide emissions associated with oil and gas extraction.[100] The report matched available routine emissions data from oil and gas sites with studies documenting health effects of these levels, and assessed the risk of accidental releases, to determine whether these warrant a national control strategy.[101] Although the report acknowledged that oil refineries and gas processing plants are a major possible source of H_2S, these were not included in the analysis because they fall outside the definition of the term 'extraction.'[102] The report also excluded exploration and well development activities. Each of these areas of oil and gas operations is a potential source of hydrogen sulfide emissions.

The report concluded that "the potential for human and environmental exposures from routine emissions of H_2S from oil and gas wells exists, but insufficient evidence exists to suggest that these exposures present any significant threat,"[103] and that "there appears to be no evidence that a significant threat to public health or the environment exists from routine H_2S emissions from oil and gas extraction."[104] The EPA reached this

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[99] New York State Department of Health, http://www.health.state.ny.us/nysdoh/environ/btsa/sulfide.htm
[100] EPA, "Report to Congress on Hydrogen Sulfide Emissions."
[101] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.III-1.
[102] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.I-4.
[103] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.iii.
[104] EPA, "Report to Congress on Hydrogen Sulfide Emissions," p.V-1.

conclusion “from the limited data available.”[105] However, because, as the report itself acknowledged, there is not enough information on ambient air quality around well sites,[106] the conclusion that there are no health risks is ill founded. A call for further research would have been more appropriate, but strikingly, the “Research and Further Studies” section of the last chapter does not recommend additional research of routine hydrogen sulfide emissions and health effects.

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[105] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.V-1.
[106] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-1.

Table 2: Summary of Studies

	Author(s) / Date	Discipline	Motivation for Study / Summary of Findings
Acute Exposure	Fuller and Suruda (2000)	Medicine	To determine the number of occupational deaths related to hydrogen sulfide; review of OSHA records; acute exposure
	Milby and Baselt (1999)	Medicine / Toxicology	Review of literature on hydrogen sulfide; focusing on neurotoxic effects of acute exposure, effects on the lungs, diagnosis of poisoning, and community exposure issues.
	Hessel et al. (1997)	Public Health	To assess pulmonary health effects of oil and gas workers in Alberta, Canada; administered questionnaire to 175 workers
	Snyder et al. (1995)	Medicine	To assess neurological problems from exposure to hydrogen sulfide; review of case reports from an incident of mass exposure to H2S in New Jersey; calls for annual neurological and neuropsychological testing of exposed subjects to enhance knowledge of long term effects
Chronic Exposure	Parti-Pellinen et al. (1996)	Medicine / Public Health	Examined health effects chronic, low-level exposure to sulfur compounds, including H2S, near a paper and pulp mill; administered cross-sectional questionnaire to 336 subjects and to a reference community; increased frequency of eye and nasal symptoms, coughs, and headaches or migraines, and acute respiratory infections.
	Legator et al. (2001)	Medicine / Toxicology / Public Health	Investigate effects of chronic exposure to low levels of hydrogen sulfide; multi-symptom health survey submitted to two exposed communities – Odessa, Texas and Puna, Hawaii, and to control communities; found central nervous system impacts: fatigue, restlessness, depression, short term memory loss, balance and sleep problems, anxiety, lethargy, headaches, dizziness, tremors; respiratory system impacts: wheezing, shortness of breath, coughing; and various ear, nose, and throat symptoms.
	Tarver and Dasgupta (1997)	Chemistry	To determine hydrogen sulfide concentrations near oil fields in Western Texas
	Xu et al. (1998)	Medicine / Epidemiology	To determine effects of exposure to hydrogen sulfide on the reproductive system; conducted a retrospective epidemiological study to assess the association between spontaneous abortion and exposure to petrochemicals in Beijing, China; found an association.
	Kilburn (1999)	Epidemiology	To determine long-term effects of exposure to hydrogen sulfide; examined and submitted a questionnaire to four groups of people that were exposed to hydrogen sulfide (from boreholes in the ground, downwind of a refinery, due to an oil refinery explosion, and a group of people exposed to odors); found abnormal balance, delayed verbal recall, impaired color discrimination and grip strength.
	Schiffman et al. (1995)	Psychiatry	To determine the effect of persistent environmental odors on the mood of people living near the source of odors; submitted a questionnaire to 44 subjects and 44 controls; found more tension, depression, fatigue, and confusion, and less vigor among the exposed subjects.
	Kilburn (2003)	Epidemiology	To measure long term effects of hydrogen sulfide exposure – various lengths of exposure and various concentrations; submitted a questionnaire, and performed neuropsychological and neurophysiological tests on 19 exposed subjects and 202 unexposed subjects; found elevated tensions, depression, anger, fatigue, and confusion, and more prevalent respiratory symptoms among exposed subjects.
Other	Layton and Cederwall (1987)	Engineering / Public Health	Methods for improving the prediction and management of public health risks associated with development of sour gas wells
	Knight and Presnell (2005)	Medicine / pathology	Review of literature on H2S toxicology; case study of two fatalities due to occupational exposure to H2S

6. Regulations and Recommendations for Exposure to Hydrogen Sulfide

6.1 Federal Recommendations and Regulations

At the federal level, some regulations and recommendations exist to protect humans from the health effects of exposure to hydrogen sulfide. Regulations are laws that can be enforced by agencies such as the Environmental Protection Agency (EPA), the Food and Drug Administration (FDA), and the Occupational Safety and Health Administration (OSHA). Recommendations, on the other hand, do not carry the force of law, and are determined by agencies such as the National Institute for Occupational Safety and Health (NIOSH) and the Agency for Toxic Substances and Disease Registry (ATSDR), both part of the federal Centers for Disease Control and Prevention (CDC).

The American Conference of Governmental Industrial Hygienists (ACGIH), a longstanding member-based organization committed to promoting worker health and safety, also recommends exposure limits for various substances. The current ACGIH hydrogen sulfide standards are 10 ppm for the Threshold-Limit Value-Time Weighted Average (TLV-TWA), and 15 ppm for the TLV short term exposure limit (TLV-STEL). The TVL-TWA is the time-weighted average concentration to which workers can be routinely and consistently exposed over an 8-hour workday and 40-hour workweek without adverse effect. The TVL-STEL is the concentration to which workers can be exposed for short periods of time without suffering adverse health effects. The ACGIH updates its standards annually, and can relatively quickly modify its standards in response to new research.[107]

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[107] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-10.

OSHA began setting standards for workers' exposure to hazardous substances in the 1970s, and initially adopted the ACGIH values.[108] The current OSHA workplace standard for H_2S exposure is 10 parts per million (ppm), while the exposure times are longer than the ACGIH recommends. In more detail, according to OSHA, "Exposures shall not exceed 20 ppm (ceiling) with the following exception: if no other measurable exposure occurs during the 8-hour work shift, exposures may exceed 20 ppm, but not more than 50 ppm (peak), for a single time period up to 10 minutes."[109] The OSHA regulations do not specify an 8-hour time weighted average (TWA) for H_2S. Exposure to these concentrations even for the seemingly short duration of 10 minutes can nevertheless result in eye and respiratory irritation, according to several sources. The NIOSH recommended exposure limit to the OSHA 10 ppm standard is 10 minutes, and its Immediately Dangerous to Life or Health (IDLH) H_2S concentration is 100 ppm.[110] OSHA standards have the force of law, while ACGIH's and NIOSH's levels are only recommendations.

It is important to note that OSHA standards apply only to workplaces and not to domestic situations or residences. The human data on which the standards are based are from uncontrolled exposure incidents, so the levels of exposure are crudely estimated.[111] In general, the controlled exposure data is derived from animal studies and then extrapolated to humans. As one study discussed above summed up, "a precise ratio with which to predict human effects on the basis of the ratio of rat-to-human effects is

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[108] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-10.

[109] Occupational Safety and Health Administration, 29 CFR 1910.1000, available at http://www.osha.gov/dts/chemicalsampling/data/CH_246800.html

[110] NIOSH is a department within the Centers for Disease Control and Prevention. See http://www.cdc.gov/niosh/npg/npgd0337.html for NIOSH's H_2S exposure recommendations.

[111] Guidotti, Tee L. 1994. "Occupational exposure to hydrogen sulfide in the sour gas industry: some unresolved issues." *International Archives of Occupational and Environmental Health*. p.157.

lacking."[112] Further, the standards are based on the expected effects of hydrogen sulfide on healthy adult males, so people who are young, old, or have compromised immune systems may be at risk at considerably lower concentrations of H_2S. Additionally, exposure to hydrogen sulfide may affect the human reproductive system, as determined in the study by Xu et al. and reported above, so standards based on males may not protect women's reproductive health.

In addition to general standards for workplace inhalation exposure, OSHA specifically sets standards for industries in which hydrogen sulfide occurs in quantities exceeding 1500 pounds, in their Process Safety Management of Highly Hazardous Chemicals Standard (1910-119). Significantly, the oil and gas industry is exempt from this standard.[113] According to the 1993 EPA report, the reason OSHA gave for this exemption is that OSHA "continues to believe that oil and gas well drilling and servicing operations should be covered in a standard designed to address the uniqueness of the industry."[114] OSHA also proposed a monitoring program for hydrogen sulfide for drilling and service operations that occur in areas where H_2S exposure is a potential risk.[115] Neither of these exists at the time of writing.

The 1990 Clean Air Act is the primary federal law that regulates air pollution. The EPA sets the levels of various air pollutants, including the National Ambient Air Quality Standards (NAAQS) for six criteria pollutants and the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for another 188 substances commonly referred to as

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[112] Kilburn, Kaye H. "Effects of Hydrogen Sulfide on Neurobehavioral Function." 2003. p.639.
[113] OSHA, http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9760
[114] As quoted in EPA "Report to Congress on Hydrogen Sulfide Emissions," p.IV-28.
[115] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.IV-30.

HAPs.[116] The EPA does not regulate hydrogen sulfide as one of its criteria pollutants nor as one of the HAPs under the 1990 Clean Air Act. When George Bush, Sr. signed the Clean Air Act in 1990, H_2S was not among the 188 chemicals on the final HAPs list to be regulated, despite the calls of public interest groups and government scientists, some even within the EPA, for its inclusion. Hydrogen sulfide had been on the proposed original list of hazardous substances,[117] and was removed from this list as a result of successful efforts by the oil and gas, chemical, and paper industries.[118] For instance, the American Petroleum Institute, representing the interests of the oil and gas industry, argued that H_2S emissions are an "accidental-release issue" rather than a routine one,[119] and that H_2S therefore should not be regulated as one of the Clean Air Act's Hazardous Air Pollutants. This lack of an EPA standard has prompted one newspaper to label hydrogen sulfide "the least regulated common poison."[120]

Hydrogen sulfide is on the EPA's list of Extremely Hazardous Substances,[121] another category under the Clean Air Act, which regulates substances "known or may be anticipated to cause death, injury, or serious adverse effects to human health or the

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[116] According to the EPA, "Hazardous air pollutants, also known as toxic air pollutants or air toxics, are those pollutants that cause or may cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental and ecological effects." http://www.epa.gov/ttn/atw/pollsour.html

[116] Interestingly, hydrogen sulfide remained on the list as a result of "administrative error" until it was removed by a Senate Joint Resolution on August 1, 1991. See http://www.epa.gov/ttn/atw/pollutants/atwsmod.html for details.

[117] Interestingly, hydrogen sulfide remained on the list as a result of "administrative error" until it was removed by a Senate Joint Resolution on August 1, 1991. See http://www.epa.gov/ttn/atw/pollutants/atwsmod.html for details.

[118] Jim Morris. "Lost Opportunity: EPA had its chance to regulate hydrogen sulfide." November 8, 1997. *The Houston Chronicle.*

[119] As quoted in *The Houston Chronicle.*

[120] Jim Morris, *The Houston Chronicle.*

[121] Environmental Protection Agency, Chemical Emergency Preparedness and Prevention. Look for H_2S on the list at http://yosemite.epa.gov/oswer/ceppoehs.nsf/Alphabetical_Results!OpenView&Start=146

environment upon accidental release."[122] This classification requires companies that produce the substance to develop plans to prevent and respond to accidental releases. Importantly, however, this classification does not require regular emission controls of the substance.[123] Additionally, H_2S is not on the list of toxic substances whose releases companies are required to report under the EPA's Toxic Release Inventory (TRI).[124] This exclusion is due to an administrative stay put in place on August 22, 1994, as a result of lobbying by a paper, forest, and wood products industry association.[125] The administrative stay will remain in effect until the EPA decides to lift it.

At the time of writing, the EPA is considering whether to re-evaluate including hydrogen sulfide on the HAPs list of the Clean Air Act.[126] The EPA is motivated by some concerns regarding chronic and acute exposure to hydrogen sulfide.[127] Further, if they proceed with research, the EPA's findings may inform action on the current administrative stay that is responsible for exempting H_2S from TRI reporting requirements.[128]

The EPA does, however, have an inhalation reference concentration (RfC) for hydrogen sulfide, which is "an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a

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[122] Section 112(r) of the Clean Air Act, as cited in EPA, "Report to Congress on Hydrogen Sulfide Air Emissions," p.i.

[123] Jim Morris, *The Houston Chronicle*.

[124] EPA's Toxic Release Inventory list of chemicals for Reporting Year 2004. Available at http://www.epa.gov/tri/chemical/RY2004ChemicalLists.pdf

[125] See http://www.epa.gov/tri/guide_docs/2001/brochure2000.pdf, footnote on p.18.

[126] Personal communication with Jim Hirtz, February 24, 2006. US EPA, Health and Environmental Impacts Division, Research Triangle, North Carolina. The EPA undertook this action in response to a request by an environmental organization from Texas.

[127] Personal communication with Jim Hirtz, February 24, 2006. US EPA, Health and Environmental Impacts Division, Research Triangle, North Carolina.

[128] Personal communication with Jim Hirtz, March 2, 2006. US EPA, Health and Environmental Impacts Division, Research Triangle, North Carolina.

lifetime."[129] The RfC is one important standard for chronic exposure. According to the EPA's on-line Integrated Risk Information System (IRIS) database, the current inhalation RfC for hydrogen sulfide is $2x10^{-3}$ mg/m^3 (1.4 ppb). Applying the RfC definition, this means that it is possible that inhaling more than this concentration on a daily basis over a lifetime poses "an appreciable risk of deleterious effects." The RfC is well below any occupational standards set by OSHA or recommended by NIOSH and the ACGIH

The EPA also recommends levels of hydrogen sulfide for their Acute Exposure Guideline Levels (AEGL) for various exposure periods. These threshold exposure limits apply to the general public for emergency exposures ranging from 10 minutes to 8 hours, and are "intended to describe the risk to humans resulting from once-in-a-lifetime, or rare, exposure to airborne chemicals."[130] Appendix A includes definitions of the AEGL categories, and the recommended H_2S levels for each exposure period and AEGL category.

Other guidelines also exist for exposure to hydrogen sulfide in emergency situations. To protect the health of the general public in the event of an emergency release, the American Industrial Hygiene Association (AIHA) establishes Emergency Response Planning Guidelines (ERPGs), which specify one-hour exposure limits. These limits are also included in the table in Appendix A.

The National Research Council's Committee on Toxicology recommended Emergency Exposure Guidance Level (EEGL) to the Department of Defense for

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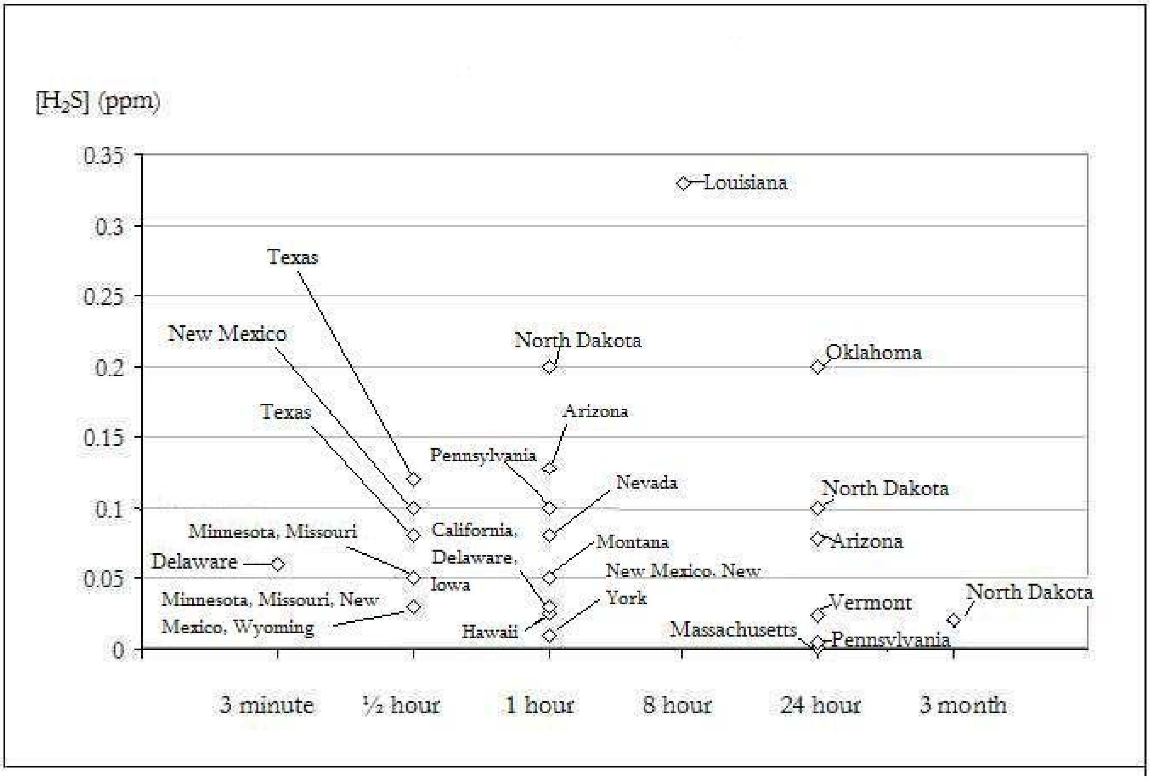
[129] EPA Integrated Risk Information System, Hydrogen sulfide (CASRN 7783-06-4), http://www.epa.gov/iris/subst/0061.htm.
[130] EPA, The Development of Acute Exposure Guideline Levels (AEGLs), http://www.epa.gov/oppt/aegl/index.htm

maximum concentrations acceptable in rare situations such as spills and fires.[131] The EEGLs apply to young and healthy military personnel, and exist for 41 substances, of which hydrogen sulfide is one. The 10 minute EEGL for H_2S is 50 ppm, and the 24 hour H_2S EEGL is 10 ppm.[132]

6.2 State Regulations

In the absence of federal standards for ambient levels of hydrogen sulfide, twenty states have passed their own laws to regulate H_2S emissions. Figure 2 is a snapshot of state ambient hydrogen sulfide regulations. It illustrates the wide range of existing state standards.

Figure 2: State Ambient H_2S Regulations



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[131] National Oceanic and Atmospheric Administration, Office of Response and Restoration, "Public Exposure Guidelines" at http://archive.orr.noaa.gov/cameo/locs/expguide.html

[132] As cited in the EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-14.

A detailed table listing the states with ambient H_2S standards can be found in Appendix B. States set their standards based on a variety of justifications, and if available, these are also listed in Appendix B. I compiled this data by reviewing information available on each state environmental department's website, and by speaking with appropriate staff. Some states have based their ambient standard for hydrogen sulfide on odor thresholds, while others have based their standard on health considerations, either adopting the EPA's RfC inhalation guideline, modifying the OSHA safety standard to apply to continuous exposure, or basing their standard on other health studies. The fact that these states have taken the initiative to regulate ambient H_2S indicates that there is concern for human health even at these relatively low levels.

Many states' health/environmental departments routinely receive odor complaints about hydrogen sulfide. Specifically, staff at agencies in Colorado, Idaho, Iowa, Kansas, Michigan, Montana, Nevada, New Mexico, Ohio, Oregon, Texas, and Wyoming reported receiving many H_2S odor complaints. In Kansas and Ohio, people have also complained about health effects from hydrogen sulfide. In Colorado, there have been some cattle deaths attributed to exposure to hydrogen sulfide, which had collected in low-lying areas.

In addition to inquiring about ambient hydrogen sulfide standards, I collected information about any monitoring of H_2S – routine or otherwise – that the state agency conducts. The most frequently cited reason for the lack of routine monitoring, even in states with ambient H_2S standards, are budget constraints. A number of people said that monitoring and more information in general would be desirable. Some states have conducted periodic, project-based monitoring of hydrogen sulfide. Studies of hydrogen sulfide emissions from Arkansas, Colorado, Louisiana, New Mexico, and North Dakota are available. These studies are of varying quality and scope, but each sheds some light on the topic of hydrogen sulfide emissions and oil and gas operations.

6.2.1 Special H_2S Monitoring Studies

6.2.1.1 Arkansas

The Arkansas Department of Environmental Quality conducted two hydrogen sulfide monitoring studies in response to numerous health and welfare related concerns of Texarkana residents about emissions from gas processing plants in the area.[133] The first study, spanning 1995 to 1997, was a scoping study to determine whether hydrogen sulfide was indeed present in ambient air and to determine whether the facilities that were emitting H_2S were in compliance with their emissions permits. After this study established that H_2S was present in the air, a second, more rigorous study was conducted from March 1998 through March 1999. The state does not have an ambient hydrogen sulfide standard.

The monitoring data from the latter study has been reported to the EPA's Air Quality System (AQS) database. The AQS database contains measurements of air pollutants – criteria pollutants, hazardous air pollutants, and other monitored substances – and this data is publicly available.[134] The Arkansas Department of Environmental Quality itself did not provide any monitoring data or comments. Data from the AQS site[135] is available for two monitoring locations, which are classified as rural residential. At the first monitoring location, the mean concentrations for the monitoring periods from May to

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[133] Pleasant Hills H_2S Study, obtained February 2006 by mail from Jay Justice, Senior Epidemiologist with the Arkansas DEQ.

[134] http://www.epa.gov/air/data/aqsdb.html

[135] http://oaspub.epa.gov/aqspub1/aqs_query.psite The code for hydrogen sulfide is 42402.

July 1998, and October to December 1998, were 2.4 ppb and 3.4 ppb, respectively, and the maximum hydrogen sulfide concentrations were 35 ppb and 24 ppb, respectively. The levels of H_2S recorded at the second monitoring location for which data is available on the AQS site were slightly higher than at the first. The mean concentration in December 1998 was 4 ppb, and in January 1999, 5.5 ppb. The maximum concentration recorded in those months were 55 ppb and 127 ppb, respectively. These levels of hydrogen sulfide, while not very high, are nevertheless higher than normal urban background levels of up to 0.33 ppb.[136] The levels measured in this study may be expected to produce a persistent odor, which has been shown in one study (Schiffman et al., 1995) to have a negative effect on the mood of nearby residents. Based on the literature reviewed above, there is little evidence of more serious health effects attributable to these levels of H_2S.

6.2.1.2 Colorado

In 1997, the Colorado Department of Public Health and Environment (CDPHE), Air Pollution Control Division, conducted a monitoring study of H_2S concentrations near several known sources, and of urban and rural background ambient levels.[137] The CDPHE initially considered monitoring at oil and gas sites because of the information in the 1993 EPA report on emissions of H_2S at points of oil and gas extraction. Ultimately, the Colorado study excluded oil and gas operations, because of assurances from the Colorado Oil and Gas Conservation Commission (COGCC) that elevated H_2S levels are not

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[136] Agency for Toxic Substances and Disease Registry (ATSDR). 2004. Toxicological profile for hydrogen sulfide (*Draft for Public Comment*). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Chapter 2, p.1.

[137] “Hydrogen Sulfide Concentrations in Colorado; Results from a Screening Survey.” Prepared by The Technical Services Program, Air Pollution Control Division, Colorado Department of Public Health and the Environment, 1997. Obtained February 2006 by mail from Ray Mohr, CDPHE.

common in deposits in Colorado.[138] However, interviews with people living near oil and gas sites in Colorado, presented below, suggest that hydrogen sulfide is present near these facilities. The COGCC itself has not conducted any monitoring of H_2S at oil and gas sites. Thus, the question of what concentrations of hydrogen sulfide are present near oil and gas operations in the state is still unanswered. Colorado does not have an ambient hydrogen sulfide standard.

6.2.1.3 Louisiana

The Louisiana Department of Environmental Quality, motivated by numerous odor complaints from nearby residents, monitored hydrogen sulfide and sulfur dioxide concentrations downwind of the Calumet Refinery in Shreveport.[139] The hourly average concentration for hydrogen sulfide, for the monitoring period from October 2002 to April 2005, was 2.56 ppb, with a maximum of 50.15 ppb and a median of 1.92 ppb.[140] These measurements correspond to the range of the monitoring data from Arkansas, and the same analysis of potential health effects applies.

6.2.1.4 New Mexico

In February 2002, the Air Quality Bureau of the New Mexico Environment Department monitored hydrogen sulfide levels to determine if ambient concentrations near certain facilities are in compliance with the state's ambient standards.[141] Air samples

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[138] "Hydrogen Sulfide Concentrations in Colorado," p.2.

[139] James M. Hazlett, "Report for the Calumet Air Monitoring Project," Louisiana Department of Environmental Quality, Office of Environmental Assessment. June 8, 2005. (obtained from the author and used with permission.)

[140] Hazlett, p.4.

[141] New Mexico Environment Department (NMED), Air Quality Bureau. "Trip Report: H_2S Survey, March 18-22, 2002." By Steve Dubyk and Sufi Mustafa. Obtained from the author.

were collected near a sewage treatment plant, four dairy operations, a poultry operation, one liquid septage facility, one sewage sludge disposal facility, and several oil and gas facilities.[142] Table 3 presents the data from the monitors near the oil and gas facilities, and a discussion of the results follows.

Table 3: Summary of Monitoring Data from New Mexico Study

Facility type	**H_2S concentration measured at monitoring site (ppb)[143]**	
	Range	**Average**
Indian Basin Hilltop, no facility	5 – 8	7
Indian Basin Compressor Station	3 – 9	6
Indian Basin Active Well Drilling Site	7 – 190	114
Indian Basin Flaring, Production, and Tank Storage Site	4 – 1,200	203
Marathon Indian Basin Refining and Tank Storage Site	2 – 370	16
Carlsbad City Limits, near 8 to 10 wells and tank storage sites	5 –7	6
Carlsbad City Limits, Tracy-A	5 – 8	7
Compressor station, dehydrators – Location A	4 –5	4
Compressor station, dehydrators – Location B	2 – 15,000	1372
Huber Flare/Dehydrating Facility [a]	4 – 12	77
Snyder Oil Well Field	2 – 5	4
Empire Abo Gas Processing Plant	1 – 1,600	300
Navajo Oil Refinery	3 – 14	7 - 8

[a] Strong winds, flare not operating correctly at time of sampling may have caused lower readings than expected, according to study, p.8.

The New Mexico data indicates that ambient concentrations of hydrogen sulfide at the sampling locations, which included both oil and gas facilities and sites without oil and gas facilities, are at least an order of magnitude greater than 0.11 to 0.33 ppb, which are the ambient levels of H_2S that can normally be expected in urban areas.[144] The ambient levels recorded at the two sites without expected sources of H_2S – Indian Basin Hilltop, no facility and Carlsbad City Limits, Tracy-A – both averaged 7 ppb, indicating that usual

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[142] NMED Trip Report, p.1.

[143] The monitor that the NMED used recorded hydrogen sulfide concentrations every 30 seconds for 3 minutes. The averages reported in this table are averages of 3-minute mean concentrations.

[144] Agency for Toxic Substances and Disease Registry (ATSDR). 2004. Toxicological profile for hydrogen sulfide (*Draft for Public Comment*). Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Chapter 2, p.1.

H_2S concentrations in this part of New Mexico are higher than normal urban background levels.

Hydrogen sulfide levels sampled at flaring, tank storage, and well drilling sites, averaging from approximately 100 to 200 ppb, are significantly elevated compared to normal background levels, and compared to usual background H_2S concentrations in this area of New Mexico. While these concentrations generally produce a nuisance due to odors which may translate into headaches, nausea and sleep disturbances if exposure is constant, one study discussed above (Legator et al., 2001) found central nervous system, respiratory system, and ear, nose and throat symptoms associated with annual average hydrogen sulfide levels ranging from 7 to 27 ppb. Overall, the data shows that concentrations of H_2S vary widely, even at similar facilities: at one compressor / dehydrator, the average concentration over the course of monitoring was 4 ppb, while at another, the average was 1372 ppb. The data further demonstrates that H_2S is present, often at quite elevated levels, at oil and gas facilities. A staff person at the NMED indicated that there is need for more monitoring and a better-designed study, but that budget constraints prevent them from routine monitoring. The department had rented a hydrogen sulfide monitor for this study.

6.2.1.5 North Dakota

The North Dakota State Department of Health and Consolidated Laboratories monitored hydrogen sulfide emissions from oil and gas wells at several locations, from 1980 until 1992. Each location was near at least one oil or gas well. At one location, the Lostwood Wildlife Refuge monitoring station, the highest one hour average concentration recorded was 88 ppb, in 1990.[145] At Lone Butte, 6 miles north of the Theodore Roosevelt National Park, one hour average hydrogen sulfide concentrations frequently exceeded 200 ppb.[146] At another site, in a valley with several wells within one mile from the monitor, recorded concentrations were as high as 250 ppb.[147] These findings highlight the fact that hydrogen sulfide is routinely emitted near oil and gas wells.

These monitoring studies reveal that hydrogen sulfide is present at oil and gas facilities, including oil refineries, gas processing plants, oil and gas wells, flares, and compressor stations. These types of facilities are commonly situated near residences, where people can be routinely exposed to hydrogen sulfide. The levels of H_2S range from relatively low concentrations of 2 ppb recorded in Louisiana to the much higher concentrations observed in New Mexico and North Dakota.

6.2.2 Routine Monitoring

Of the twenty states that have an ambient hydrogen sulfide standard, only three – California, Oklahoma, and Texas – conduct routine monitoring of ambient H_2S concentrations. The other eighteen states do not monitor ambient H_2S levels. Rather, the standard is generally used in permitting facilities that emit hydrogen sulfide. Typically, the health/environmental departments model emissions and permit a facility if the model reports that the emissions would not raise ambient levels above the standard.

6.2.2.1 California

The California Air Resources Board (CARB), which manages air quality and pollution in the state, has authority to enforce the state ambient hydrogen sulfide standard

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[145] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-22.
[146] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-26.
[147] EPA, “Report to Congress on Hydrogen Sulfide Emissions,” p.III-30.

of 30 ppb, averaged over one hour. CARB also delegates management to the state's 35 Air Pollution Control Districts (APCDs) or Air Quality Management Districts (AQMDs), each with authority to adopt its own rules and regulations to control and monitor emissions of hydrogen sulfide. A map of the state air districts is in Appendix C. The local districts defer to the state ambient standard, but they are in charge of conducting monitoring of ambient H_2S.

The twelve sites in California where hydrogen sulfide is routinely monitored were chosen because of nearby emission sources. Table 4 summarizes the monitoring sites and the sources of H_2S. I discuss the data for 2005 from Contra Costa and Santa Barbara Counties, where the H_2S sources are due to oil and gas facilities. Daily averages of hourly hydrogen sulfide readings at the three monitoring sites in Contra Costa County range from 0.000 to 0.003 ppm, with one reading of 0.007 ppm at one monitoring site. Similarly, the daily averages of hourly H_2S concentrations recorded during 2005 at all three sites in Santa Barbara range from 0.000 to 0.001 ppm.[148] These levels are most likely of no health concern.

Table 4: California H_2S Monitoring Sites

District	**County**	**Sites**	**Source(s)**
Great Basin Unified APCD	Inyo	2	Geothermal Power Plant
Lake County AQMD	Lake	3	Geothermal Power Plants
Mojave Desert AQMD	San Bernardino	1	Chemical Processing Facility
San Francisco Bay Area AQMD	Contra Costa	3	Chevron Oil Refinery
Santa Barbara County APCD	Santa Barbara	3	Oil and Gas Processing Facilities

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[148] Data is available at http://www.arb.ca.gov/adam/cgi-bin/db2www/adamweeklyc.d2w/start. In Step 3, select desired county, and on the next page, in Step 1, select "Daily Average of Hourly Measurements." Use arrows on the right to select different time periods.

6.2.2.2 Oklahoma

The Air Quality Monitoring division of the Oklahoma Department of Environmental Quality (DEQ) continuously monitors ambient levels of hydrogen sulfide at sites downwind of two large oil refineries in Tulsa. The DEQ initiated the monitoring because complaints about foul odors numbered as many as 5 or 6 per day.[149] According to staff at the Oklahoma DEQ, the DEQ installed three monitors in Tulsa, and continuous hourly average data for two of the three monitors is available on-line.

Figure 3 summarizes the data on ambient H_2S levels recorded at these two sites in Tulsa. Monitor 235 is in a park right next to residences an eighth to a quarter of a mile downwind and across the river from a refinery. Monitor 501 is on a hill, two to three miles downwind of another refinery. The hill elevation approximately lines up with the height of the refinery stacks. The majority of the odor complaints mentioned above came from residents of this neighborhood. Now, the DEQ receives about 3 or 4 complaints a week. The levels of hydrogen sulfide in both neighborhoods, although not very high, are nevertheless above the EPA's RfC of 1.4 ppb, and are well elevated above normal background levels of 0.11 to 0.33 ppb. It is possible that continuous exposure to these levels poses health risks. While the Oklahoma DEQ is monitoring hydrogen sulfide levels, there is no concurrent community health or exposure study investigating the health effects of chronic exposure to these levels of H_2S.

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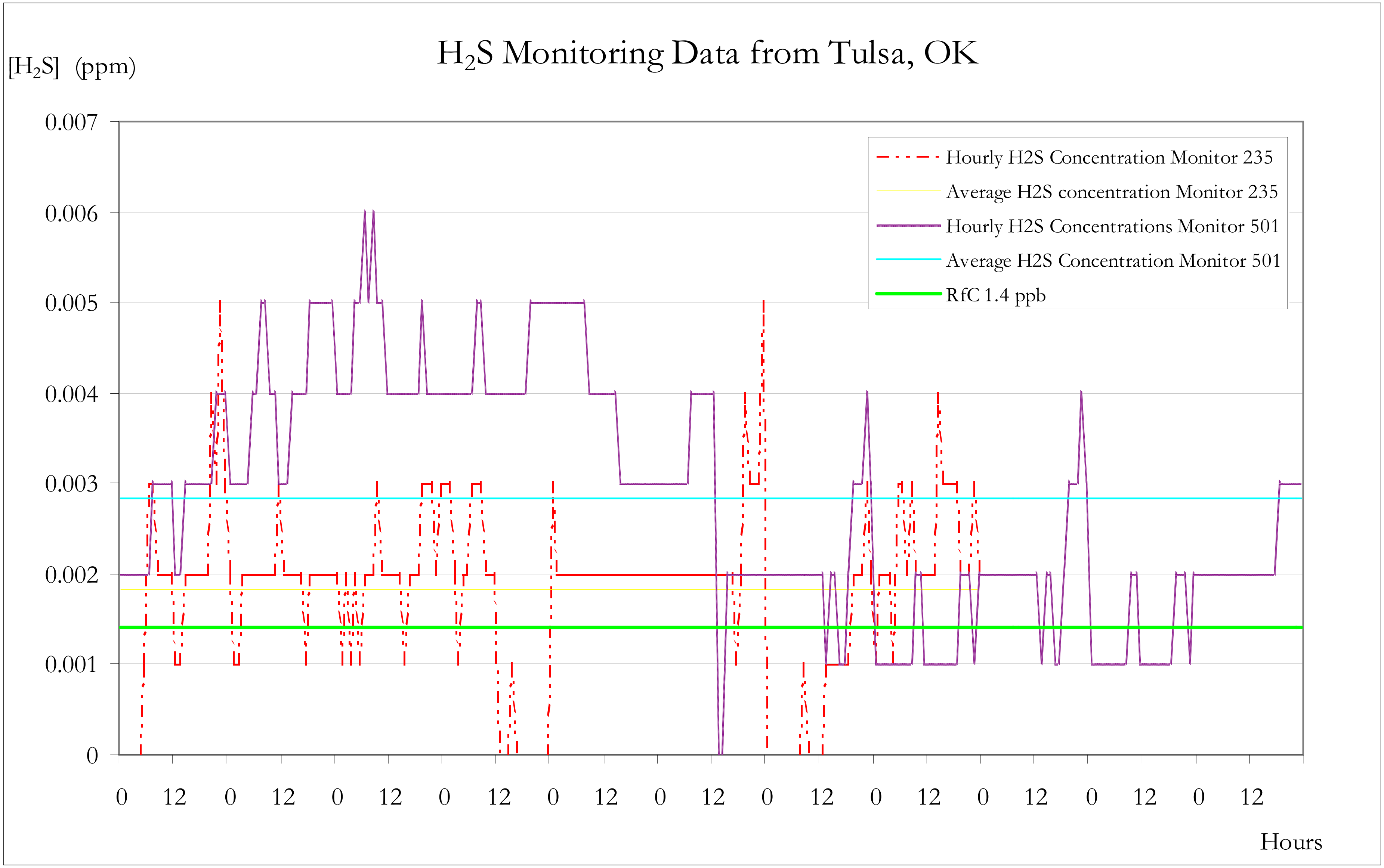
[149] Personal communication, Rhonda Jeffries, Oklahoma Department of Environmental Quality. February 10, 2006.

Figure 3: Tulsa H_2S Monitoring Data[150]



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[150] Data from http://www.deq.state.ok.us/aqdnew/monitoring/cpdata.htm#

6.2.2.3 Texas

The Texas Commission on Environmental Quality (TCEQ) coordinates a network of monitors across the state to insure compliance with its ambient air quality standards. Hydrogen sulfide is among the pollutants that are routinely monitored. There are twelve active H_2S monitors in Texas, some in residential and some in industrial areas, each near an oil or gas facility, including a refinery, a tank battery, and a compressor station.[151] The majority of the monitors register relatively low H_2S levels, ranging from 0.1 ppb to 5 ppb. However, one monitor at compressor station near a residence, consistently records elevated levels of H_2S. In December 2005, the last month for which the data has been validated by the TCEQ, 20 percent of the hourly readings exceeded the state standard of 0.8 ppm.[152] Chronic exposure to such levels, generally considered a nuisance due to odor, has also been shown to adversely affect human health, as discussed in the Literature Review – Chronic Exposure section.

7. Evidence From People Living Near Oil and Gas Operations

I conducted semi-structured, informal telephone interviews with people who believe that their health has been compromised as a result of exposure to hydrogen sulfide from oil and gas operations. Appendix D contains narratives of each interview, and provides details about each interviewee's experience. Some interviewees had previously contacted the Oil and Gas Accountability Project (OGAP), a non-profit organization working to reduce the impacts of oil and gas development on communities and the

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[151] Data and photos are available at http://www.tceq.state.tx.us/compliance/monitoring/air/monops/sites/monitors_map.html

[152] 65 out of 332 readings were above 80 ppb. (40 data points did not include readings due to equipment maintenance).

environment, about their concerns. These interviewees identified other potential interview participants. I spoke with eleven people, and obtained information about the experiences of two additional people who lived with the interviewees. Thus, the information I present here is based on the experience of thirteen people. The ages of the interview participants range from 25 to 76. To protect the privacy of the interviewees, their names and other identifying characteristics have been withheld.

Table 4 summarizes the information on the sources of H_2S, lengths of exposure, and symptoms reported by each interviewee. Hydrogen sulfide exposure was due to emissions from a variety of sources. As identified in the interviews, these consisted of a natural gas sweetening facility, natural gas and oil well sites, flaring operations at both oil and gas facilities, venting, wastewater pits, and an oil refinery. The duration of exposure also varied, from one year to as long as eleven years, and these exposure periods in several cases include instances of acute exposure to accidental high-concentration H_2S releases. Some interviewees had information on the concentrations of H_2S to which they were exposed, while others did not.

The reported health effects are consistent with exposure to hydrogen sulfide, and include both physical and neurological symptoms. The most commonly reported symptoms were pressure headaches or dull headaches (ten people), fatigue or loss of energy (seven people), and memory impairments (seven people). Dizziness, throat irritation, eye irritation, heart palpitations, and insomnia were each reported by four people, and nosebleeds by five people. Other symptoms that the interviewees are experiencing are balance problems, trouble walking, vomiting, coughing, concentration problems, skin irritations (in some cases severe), and shortness of breath.

Eight people are experiencing chemical hypersensitivity and attribute it to hydrogen sulfide exposure. Two people I interviewed have had their gall bladders removed, which may or may not have been related to hydrogen sulfide exposure, and four have been diagnosed with chemical encephalopathy (swelling of the brain). Three interviewees are on permanent Social Security disability as a result of their health problems, which they attribute to hydrogen sulfide exposure. Five separate interviewees also stated that animals in their area were experiencing health problems. Every interviewee reported that the characteristic rotten egg odor of hydrogen sulfide was commonplace at their residences. Four families that I interviewed chose to move from their previous residences because of the health problems they associate with hydrogen sulfide.

While some of the interviewees have been diagnosed by medical professionals who attributed their symptoms to exposure to hydrogen sulfide, others have not. Oil and gas operations emit a host of other pollutants in addition to hydrogen sulfide, many of which are hazardous to human health, confounding the process of ascribing health effects to just one chemical. Additional confounders are individual health factors and the potential presence of other sources of hydrogen sulfide. This difficulty of disaggregating pollutants and symptoms provides an opportunity for critics to undermine the conclusion that the health problems reported by the people I interviewed are due to hydrogen sulfide. Nevertheless, the symptoms that the interviewees experienced match the health effects associated with hydrogen sulfide exposure as reported in the toxicological studies I present above.

The interviews provide evidence, which, although it is anecdotal, attests to the fact that hydrogen sulfide is emitted at a host of oil and gas facilities, and that its continual presence in ambient air compromises human health and well being. Although the concentrations of H_2S to which the interviewees were exposed are, for the most part, not known, they likely are not very high. Except for the three cases of knockdown, the interviews show that chronic exposure to relatively low levels of hydrogen sulfide can nevertheless take a considerable toll on people's health. The health problems that the people I interviewed are experiencing are serious enough to warrant monitoring of ambient air near oil and gas facilities in residential areas to ensure that H_2S levels are not above those considered safe. Clearly, the very issue of what levels of hydrogen sulfide are "safe" is contentious, judging in part by the wide range of values that characterize states' ambient H_2S standards. More research is certainly needed, both to determine the effects of chronic exposure to low levels of H_2S and to establish a sound standard for safe exposure to H_2S.

Table 4: Summary of Interviews

	Age and Sex	Source of Emissions	Exposure Time and Concentrations	Symptoms	Diagnosis
Story 1	Male 76	Venting from tank battery	3 years ongoing, 2 acute exposures	*Ongoing*: Staggering, dizziness, pressure headaches, dry cough, shortness of breath, throat irritation, fatigue, lightheadedness, insomnia, lack of concentration, memory loss; *Acute exposure*: stiff neck, dizziness and dry heaving	chemical encephalopathy chemical hypersensitivity due to H_2S
	Male 25	Sour gas well, tank battery	Ongoing; one acute exposure-knockdown, 200 ppm	*Knockdown*: severe headache *Persistent symptoms*: very bad memory, some balance problems	
Story 2	Female 44	Oil refinery, waste water treatment plant, oil pads	Ongoing, unknown concentrations	Headaches, balance problems, concentrations problems, eye irritation, problems sleeping, general pain, low muscle strength, trouble walking, problems with memory retention and reading comprehension, hypersensitivity of the skin	chemical encephalopathy
Story 3	Male and Female, mid-40s	Natural gas well flaring	Ongoing, unknown concentrations	*Wife*: pains similar to severe rheumatoid arthritis, blistering of the skin when showering, severe burns on the bottoms of her feet, skin covered in welts, fatigue, vomiting, rectal bleeding, severe sinus headaches; gall bladder removed *Husband*: rectal bleeding	None specific to H2S
Story 4	Male and Female, mid-60s	Amine plant, sour gas wells	Ongoing for 1 year; unknown concentrations	*Both*: chronic sore throat, congestion, coughing, headaches, swollen eyes, insomnia, occasional nosebleeds, and a general lack of energy. *Husband*: face burns, burning on hands and eyes. *Wife*: heart palpitations	None
Story 5	Male and female, mid-40s	Oil refinery, waste water treatment	Husband: occupational; ongoing residential Wife: ongoing; Concentrations 3 ppm; 3 or 4 times per week 10 ppm	*Husband*: bloody nose, headaches, colon polyps, burning eyes, throat itching, and itching all over, severe headaches, severe rashes, burning skin, teeth damage, nerve damage, slurred speech; on disability, unable to work *Wife*: rapidly deteriorating eyesight, ringing in her ears, memory problems, trouble with balance, tremors, trouble walking up and down stairs, and severe migraine headaches; gall bladder removed	chemical encephalopathy
Story 6	Female 50s	Sour natural gas wells flaring, tank battery	Ongoing; one acute exposure	*Acute exposure*: headache, extremely sick; *Later*: extreme fatigue, confusion, anxiety, heart symptoms, shaking and tremors when exposed to certain chemicals, dizziness, headaches, nosebleeds, memory and cognitive impairments, especially upon exposure to H2S or other chemicals, bronchial asthma symptoms *Son knocked down*: arrhythmia, balance problems, and pneumonia; *Currently:* nosebleeds, walks with a cane, experiences extreme headaches, confusion, brain fog, ongoing heart problems, burning lungs when he’s in an area with chemicals, scaling of the skin, psoriasis, and chloro-acne	chemical encephalopathy, non-recoverable

Story 7	Male 27	Gas processing plant, wells	Ongoing, one acute exposure	Acute exposure: extreme shortness of breath, close to unconsciousness Ongoing: blurred vision, brain fog, memory impairment, excessive sleepiness, lack of energy and strength, occasional diarrhea, blood in his urine, loss of libido, abnormal heart rhythm, and anxiety-like attacks, severe and protracted involuntary muscle movements in his arms and legs.	Chemical encephalopathy, optical nerve damage
Story 8	Female 50s	Gas wells, flares, condensate pits	Ongoing occupational, one acute exposure	Acute exposure: knockdown, blinding headache, fading of consciousness Ongoing: nasal irritation, balance and memory impairment, nosebleeds, nerve inflammation	Chemical sensitivity

8. Concluding Remarks

The literature on human health and hydrogen sulfide reveals serious and lasting physiological and neurological effects associated with acute exposure. The health effects of chronic exposure to lower levels of H_2S, as documented in several studies, also include persistent physiological and neurological disturbances. Oil and gas facilities can be expected to accidentally and routinely emit hydrogen sulfide in concentrations that span a wide range and are associated with a variety of health effects. Academic studies, my conversations with health department staff, and available data from monitoring projects help establish that hydrogen sulfide is indeed present near oil and gas facilities.

Because people live near oil and gas sites, emissions of H_2S may be routinely compromising human health. The interviews I conducted with people who live close to oil and gas facilities, as well as some research reported in the Literature Review section, provide evidence of health impacts from exposure to H_2S emitted by oil and gas development. Although the anecdotal evidence from my interviews is vulnerable to criticism that other pollutants or individual health factors may be responsible for the symptoms, the reported health effects are consistent with hydrogen sulfide exposure. The fact that concentrations of H_2S to which people are exposed are often not known does not imply that hydrogen sulfide is not the cause of the observed health effects. The lack of precise exposure data is, however, one area that future research should address.

In the meanwhile, people's health needs to be protected. The proximity of oil and gas wells to people's residences is one route of exposure to hydrogen sulfide, and to other pollutants associated with oil and gas extraction. The persistence of the land ownership pattern known as 'split estate,' under which one entity owns the rights to the surface of the property and another to the minerals under the surface, is partly responsible for the proximity of oil and gas facilities to residences. Another factor are low setbacks, the minimum distance required between an energy facility and a specific type of development.[153] For example, in Colorado, where some of the interviewees live, the residential setback requirement for oil and gas wells is 150 feet.[154] In Texas, the setback is also 150 feet,[155] while the New Mexico residential setback is just 100 feet.[156] In Alberta, Canada, the residential setback requirement for sour gas wells areas is 100 m (approximately 330 feet).[157] While greater than Colorado's and Texas's required setback, this distance may not be sufficient, as some of the interviewees were exposed to hydrogen sulfide in Alberta. To truly provide a margin of safety and protection to people who live in areas of oil and gas development, whether the facilities are on their surface property or not, greater setback distances need to be established. The siting of oil refineries and gas processing plants near residences, and conversely, building homes near existing refineries and gas plants, exposes people to a host of pollutants, including hydrogen sulfide. This is often an issue with the dimension of social and environmental justice added to questions of protecting public health.

Some technological options exist that may help mitigate the effects of hydrogen sulfide on the health of people who live near emission sources. One advanced technology for odor control, consisting of a dry scrubbing system with multiple beds of engineered media (made by soaking, or on a rotating agglomeration disk), removed hydrogen sulfide at a wastewater

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[153] http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_0_257_229_0_43/http%3B/extContent/publishedcontent/publish/eub_home/public_zone/eub_process/enerfaqs/EnerFAQs5.aspx#1

[154] Colorado Oil and Gas Conservation Commission, Rule 603. Available at http://oil-gas.state.co.us/RR_Asps/600Series.pdf

[155] Texas Administrative Code, Title 16, Part I, Chapter 3, Rule 3.21 (a) and (i). Available at http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y

[156] Personal communication, Denny Foust, New Mexico Environment Department, April 12, 2006.

[157] Alberta Energy and Utilities Board, Directive 056, Energy Development Applications and Schedules. Available at http://www.eub.ca/docs/documents/directives/directive056.pdf, pp.54-55.

treatment facility with an efficiency of 99.94 percent.[158] This odor control technology reduced the peak inlet hydrogen sulfide concentration of 108.0 ppm to 0.061 ppm.[159] Such odor abatement technologies could be required at all facilities that emit hydrogen sulfide, including oil refineries and gas processing plants. At points of oil and gas extraction and processing, requiring high efficiency flares would ensure that less hydrogen sulfide (and other pollutants) escape into ambient air unburned.

As I show in the Regulations and Recommendations section, at the federal level, the oil and gas industry and the paper and pulp industry have exerted their influence to prevent H_2S from being included on the Clean Air Act's Hazardous Air Pollutants (HAPs) list, and to exempt it from reporting under the EPA's Toxic Release Inventory (TRI). At the time of writing, the EPA is reviewing both decisions, which at the very least indicates that some concern exists over the lack of stricter regulation of hydrogen sulfide at the federal level. The level of regulation of hydrogen sulfide varies widely across the states that have established an ambient standard in the absence of a federal one, but again, the very existence of ambient standards suggests that hydrogen sulfide is a concern.

Monitoring of ambient H_2S is necessary to determine exactly how much is being emitted and to clarify the link between exposure and health effects. Enough evidence of routine H_2S emissions at oil and gas facilities emerges from my conversations with health department personnel, interviews with people living near oil and gas sites, several studies summarized in the Literature Review section, and state monitoring projects to merit more comprehensive monitoring. The lack of federal standards for ambient H_2S levels or for emissions of H_2S is one reason for sparse monitoring even at state level, since state health / environmental departments

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[158] Gailey, Karen. 2004. "Goodbye Odors, Hello Happy Neighbors." *Pollution Engineering*. p.30.
[159] Gailey, Karen. 2004. "Goodbye Odors, Hello Happy Neighbors." *Pollution Engineering*. p.30.

largely depend on federal funding for their projects. More routine and special project monitoring would facilitate conducting community health studies, by providing accurate exposure data that could be matched with observed health effects.

In light of the information presented here on the health effects associated with exposure to hydrogen sulfide, even though rigorous data on the dose-response relationship is lacking, it is irresponsible and callous to delay making some public policy decisions that would help protect human health.

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Appendix A: Guidelines for Occupational Exposure to Hydrogen Sulfide

[H_2S] (ppm)	Agency	Duration	Comments
0.1	AIHA [a]	ERPG- 1 1 hour	Maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing other than mild, transient adverse health effects or perceiving a clearly defined objectionable odor; based on human odor detection.
0.33	EPA [b]	AEGL 1 8 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic nonsensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.
0.36	EPA [b]	AEGL 1 4 hours	
0.51	EPA [b]	AEGL 1 1 hour	
0.6	EPA [b]	AEGL 1 30 minutes	
0.75	EPA [b]	AEGL 1 10 minutes	
10	ACGIH [c]	TLV-TWA 8hr/day, 40hr/week	Occupational exposure
10	OSHA [d]	8hr/day, 40hr/week	Occupational exposure
10	NIOSH [e]	10 minutes	Recommended exposure time to 10 ppm in the workplace
15	ACGIH [c]	TVL-STEL Short periods of time	Occupational exposure for short periods of time
17	EPA [b]	AEGL 2 8 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
20	EPA [b]	AEGL 2 4 hours	
20	OSHA [d]	Ceiling	Ceiling, if no other exceedence of 10 ppm standard
27	EPA [b]	AEGL 2 1 hour	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
30	AIHA [a]	ERPG-2 1 hour	Maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take productive action; based on animal studies
31	EPA [b]	AEGL 3 8 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death.
32	EPA [b]	AEGL 2 30 minutes	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
37	EPA [b]	AEGL 3 4 hours	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death.
41	EPA [b]	AEGL 2 10 minutes	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.
50	OSHA [d]	10 minute ceiling	If no other measurable exposure during 8 hr shift
50	EPA [b]	AEGL 3 1 hour	Airborne concentration above which it is predicted that the general population, including susceptible individuals, could

59	EPA [b]	AEGL 3 30 minutes	experience life-threatening health effects or death.
76	EPA [b]	AEGL 3 10 minutes	
100	NIOSH [d]	IDLH	Immediately Dangerous to Life and Health
100	AIHA [a]	ERPG-3 1 hour	Maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects; based on human studies

[a] Source: EPA, http://www.epa.gov/oppt/aegl/define.htm and http://www.epa.gov/oppt/aegl/results57.htm

[b] Source: AIHA, 2005 American Industrial Hygiene Association, available at http://www.aiha.org/1documents/Committees/ERP-erpglevels.pdf, and EPA Report, 1993 p.III-11, 13.

[c] EPA "Report to Congress on Hydrogen Sulfide Emissions," p.III-10.

[d] Occupational Safety and Health Administration, 29 CFR 1910.1000, available at http://www.osha.gov/dts/chemicalsampling/data/CH_246800.html

[e] Source: NIOSH is a department within the Centers for Disease Control and Prevention. See http://www.cdc.gov/niosh/npg/npgd0337.html for NIOSH's H_2S exposure recommendations.

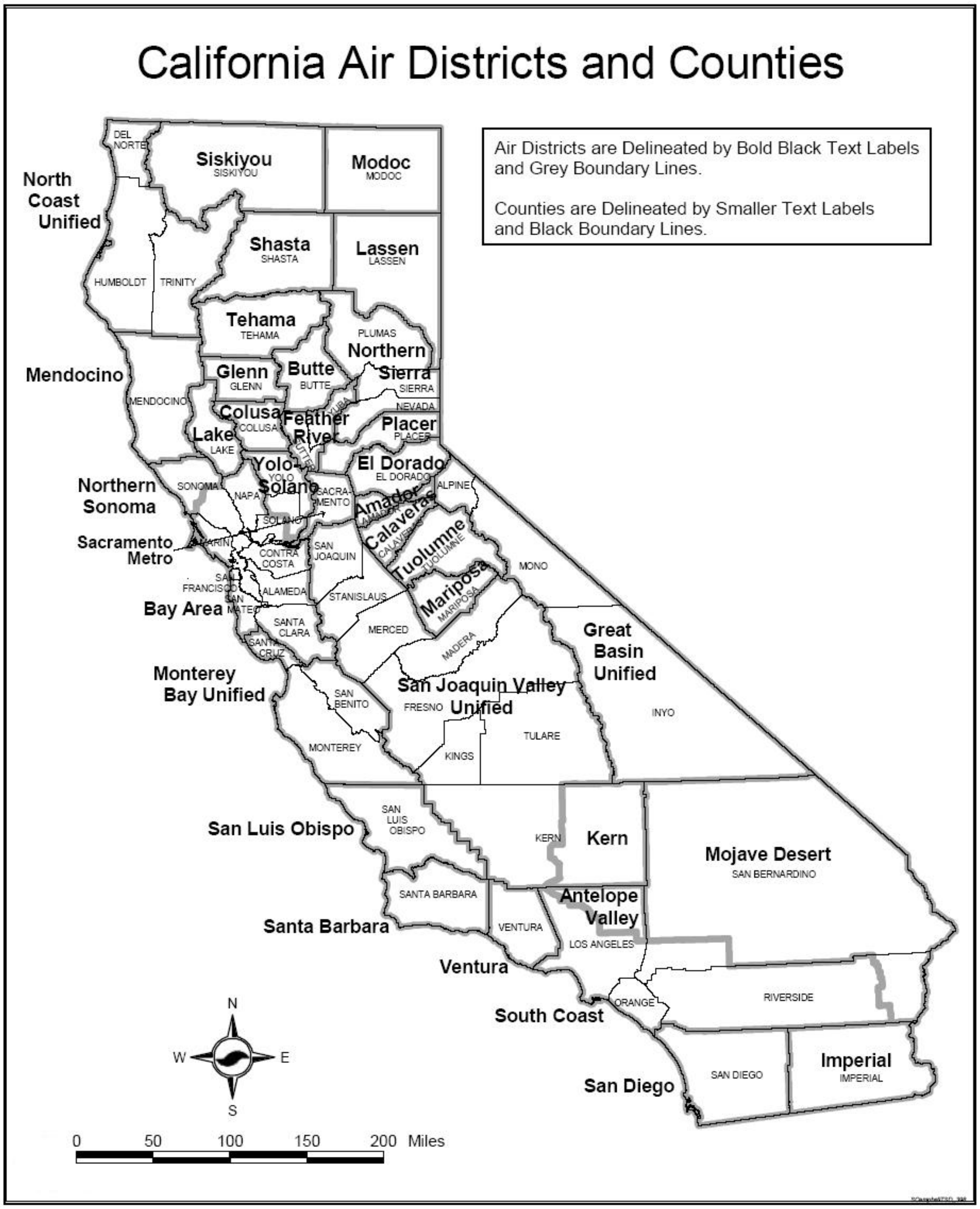
Appendix B: State Ambient Hydrogen Sulfide Standards

State	Standard	Duration	Justification	Source
Arizona	180 µg/m3 (0.128 ppm)	1 hr	AAAQG, health based, on OSHA guidelines	www.azdeq.gov/environ/air/permits/download/ambient.pdf
	110 µg /m3 (0.078ppm)	24 hr		
California	0.03 ppm	1 hr		California Air Resources Board, Nov 2005: http://www.arb.ca.gov/aqs/aaqs2.pdf
Delaware	0.06 ppm	average concentration not to be exceeded taken over any consecutive 3 minutes		Regulation 3, Delaware Ambient Air Quality Standards, www.dnrec.state.de.us/air/aqm_page/docs/pdf/reg_3.pdf
	0.03 ppm	average concentration not to be exceeded taken over any consecutive 60 minutes		
Hawaii	25 ppb	1 hr	Combination of health and nuisance	Hawaii State Ambient Air Quality Standards, www.hawaii.gov/health/environmental/air/chart.pdf
Iowa	30 ppb	1-hr daily maximum	"health effects standard"	www.legis.state.ia.us/Rules/2004/Bulletin/IAB040818.pdf
Louisiana	330 ppb	8-hr average	NIOSH/OSHA safety standard, took 1/42 of their level	Personal Communication, Jim Hazlett, Air Quality Assessment, Louisiana Department of Environmental Quality
Massachusetts	0.65 ppb	24-hr and annual limit	Based on EPA RfC, Threshold Effects Exposure Limit and Allowable Ambient Limit	Massachusetts Rule 310: Ambient Air Exposure Limits for Chemicals www.mass.gov/dep/air/aallist.pdf
Minnesota	0.05 ppm (70 µg /m3)	1/2 hr average not to be exceeded over 2 times per year		Minnesota Pollution Control Agency, State Ambient Air Quality Standards, Chapter 7009.0080 www.revisor.leg.state.mn.us/arule/7009/0080.html
	0.03 ppm (42 µg /m3)	1/2 hr average not to be exceeded over 2 times in any 5 consecutive days		
Missouri	0.05 ppm (70 µg /m3)	1/2 hr average not to be exceeded over 2 times per year		Missouri Ambient Air Quality Standards CSR 10-6.010, www.sos.mo.gov/adrules/csr/current/10csr/10c10-6a.pdf
	0.03 ppm (42 µg /m3)	1/2 hr average not to be exceeded over 2 times in any 5 consecutive days		
Montana	0.05 ppm	hourly average, not to be exceeded more than once per year	health based	Montana Rule 17-8-214 http://deq.mt.gov/dir/legal/Chapters/CH08-02.pdf
Nevada	0.08 ppm	1-hr average	health based	Nevada Chapter 445B – Air Controls, section 22097, www.leg.state.nv.us/NAC/NAC-445B.html#NAC445BSec22097
New Mexico	0.010 ppm	1-hr average not to be exceeded more than once per year		New Mexico Ambient Air Quality Standards, Title 20, Chapter 2, Part 3 www.nmenv.state.nm.us/aqb/regs/20_2_03nmac_103102.pdf
	0.100 ppm	1/2 hour average	special for the Pecos-Permian Basin Intrastate Air Quality Control Region	
	0.030 ppm	1/2 hour average	for within five miles of municipalities in Pecos-Permian Basin that are populated areas (more than 20,000 people)	

New York	0.01 ppm	1-hr average	odor and aesthetic	New York Rules and Regulations, Chapter III, Subpart 257-10; www.dec.state.ny.us/website/regs/subpart257_10.html
North Dakota	10 ppm	ceiling, maximum instantaneous concentration not to be exceeded	health based	North Dakota Ambient Air Quality Standards, Chapter 33-15-2 www.legis.nd.gov/information/acdata/html/..%5Cpdf%5C33-15-02.pdf
	0.20 ppm	maximum 1-hr average concentration not to be exceeded more than once per month		
	0.10 ppm	maximum 24-hr average concentration not to be exceeded more than once per year		
	0.02 ppm	maximum arithmetic mean concentration averaged over three consecutive months		
Oklahoma	200 ppb	24-hr average concentration		Oklahoma Air Pollution Control Rules, Title 252, Chapter 100-31-7 www.deq.state.ok.us/rules/100.pdf
Oregon	2 µg /m3 (0.3 ppb)*	annual average concentration	based on EPA's RfC, proposed benchmark	Personal Communication, Bruce Hope, Senior Environmental Toxicologist, Oregon Department of Environmental Quality, Air Quality Division. Feb. 10, 2006.
Pennsylvania	0.005 ppm	24-hr average		Pennsylvania Article III, Chapter 131, www.pacode.com/secure/data/025/chapter131/025_0131.pdf
	0.1 ppm	1-hr average		
Texas	0.08 ppm	30-min average	if the downwind concentration of hydrogen sulfide affects a property used for residential, business, or commercial purposes	Texas Administrative Code, Title 30 Part 1, Chapter 112, subchapter B; http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=112&sch=B&rl=Y
	0.12 ppm	30-min average	if the downwind concentration of hydrogen sulfide affects only property used for other than residential, recreational, business, or commercial purposes, such as industrial property and vacant tracts and range lands not normally occupied by people.	
Vermont	33.3 µg /m3 (0.024 ppm)	24-hr	health based	proposing 1 µg /m3 annual average, to be determined in April; current standard available at http://www.anr.state.vt.us/air/docs/apcregs.pdf
Wyoming	70 µg /m3 (0.05 ppm)	1/2 hour average not to be exceeded more than 2 times per year		Wyoming Department of Environmental Quality, Air Quality Division, Ambient Air Quality Standards, Chapter 2: http://deq.state.wy.us/aqd/stnd/Chapter2_2-3-05FINAL_CLEAN.pdf
	40 µg /m3 (0.03 ppm)	1/2 hour average not to be exceeded more than 2 times in any 5 consecutive days		

* Proposed, to be reviewed April 2, 2006

Appendix C: California Air Districts



Appendix D: Interview Narratives

Story 1

One participant, a 76-year-old rancher, used to own and live on a ranch on flat prairie land in Alberta, Canada. His property was three quarters of a mile straight east and downwind of an oil facility, which included a tank battery where impurities such as sand and salt water were removed from the oil to prepare it for the pipeline. According to government figures which he claims to have obtained, the oil initially contained 8% hydrogen sulfide. This figure increased to 13% after a few years of production. The interviewee believes that H_2S emissions affected people within a radius of up to three miles from the facility.

Venting to the atmosphere from several big tanks in the battery released hydrogen sulfide, as oil added to the tanks stirred up the settled oil, emitting H_2S. For the first three years of the facility's operation, there was no flare, and the hydrogen sulfide would accumulate and then be vented.

This interviewee was exposed to hydrogen sulfide many times before he realized what was taking place. He often woke up dizzy, and reports staggering for a half hour before regaining his balance for the rest of the day. Initially, he thought the dizziness was due to high blood pressure, but tests revealed that his blood pressure was normal. During and after every exposure, he experienced angina pains (pain due to lack of oxygen to the heart muscle) while walking even short distances. After moving away, the angina improved and he is able to control it with medication. Nevertheless, he has undergone six by-pass surgeries. Additionally, he experienced pressure inside his head and short term memory loss.

This interviewee experienced health problems as a result of several specific hydrogen sulfide releases from the tank battery. He believes he was exposed to a very high, but unknown, concentration of hydrogen sulfide on one occasion, when he was harvesting crops approximately 500 feet from the oil facility's fence line. He recalls briefly smelling the rotten egg odor, and then not noticing it further. At that time, he experienced a stiffening of the neck and shoulders, and his head 'froze' in the position he had turned it. Now, if he is exposed to hydrogen sulfide, he experiences similar but not as severe symptoms of the head, neck, and shoulders.

On another occasion, when the rotten egg odor characteristic of hydrogen sulfide was especially strong outside the house, he was sick for three days. During this episode, which he attributes to many small exposures over the three days, his balance was disrupted so that he could not stand when he stood up, and he experienced dry heaving. After this episode, he started to be observant and to study the effects of hydrogen sulfide on human health. He used the Internet and visited other people who had problems due to H_2S, and found that his symptoms matched hydrogen sulfide exposure.

The interviewee eventually purchased a hydrogen sulfide monitor, and he reports that there were short periods of time when H_2S concentrations were very high. On one occasion, his 17-year-old grandson experienced knockdown while monitoring for hydrogen sulfide on the property. The monitor recorded 200 ppm at that time. His grandson had been exposed at other times while working on the ranch, and had difficulty in school after the knockdown.

I also spoke with the grandson about his knockdown. He experienced dull headaches in the front of his head whenever he was exposed to H_2S. He remembers having a very intense headache right before the incident. His head and neck stiffened, and he lost consciousness. Since this exposure, he has difficulty remembering details and notices his memory getting progressively worse. His balance is not as good as it used to be, and he experiences hot flashes several times per week.

The older interviewee sought medical help on many occasions because of his health problems. Eight hours of testing by an H_2S specialist ruled out Alzheimer's, Parkinson's, and Lou Gehrig's diseases, as well as progressive blindness and deafness. According to this professional's letter, which the interviewee read to me, the diagnosis was of a "75-year-old man who had extensive exposure" and now suffers from chemical encephalopathy (swelling of the brain) due to H_2S, small airways obstruction beyond that due to cigarette smoking and attributable to H_2S, $SO_{2,}$ and diesel exhaust, and chemical hypersensitivity due to H_2S exposure. His symptoms are a dry cough, shortness of breath, throat irritation, fatigue, lightheadedness, dizziness, insomnia, lack of concentration, and memory loss. The symptoms that improved after moving are throat and eye irritation and balance, but the others persist.

There have also been problems with cattle in the area, including spontaneous abortions and animals' hooves falling off and not healing.

Story 2

A 44-year-old woman has suffered many health impacts from exposure to hydrogen sulfide and from an oil refinery, and there are many pump jacks, collection ponds, and tank batteries close to her residence.

The oil refinery transfers its wastewater and production water to the municipal wastewater treatment facility, which also received wastewater from a dairy facility until 2001.[160] Her husband, who was employed at the wastewater treatment facility and had previously worked for an oil company, is now on permanent Social Security Disability Leave because repeated exposure rendered him physically and psychologically unfit to work. According to a safety company monitoring data that she has seen, she reported that concentrations of 10 ppm are commonplace in the street in front of the wastewater treatment plant. A park where children play is across the street from the plant.

She believes that she is exposed to hydrogen sulfide daily or almost daily. The smell of rotten eggs is regularly present in town and at her residence. Sometimes, the odor is very strong for a short time, “a minute or so,” and then she no longer detects it. She thinks this is due to concentrations above the odor threshold, which occurs between 50 and 100 ppm.[161] At other times, visitors new to the area could detect an odor while she could not. She thinks her nose is no longer as sensitive to the odor of H_2S due to chronic exposure.

As a result of her and others’ complaints, the Center for Disease Control’s ATSDR sent personnel to her property to monitor for H_2S. Based on the levels they found in the ambient air, ATSDR has plans to follow up with water and soil sampling on the property. Although the monitors registered H_2S, the ATSDR took no action because of a lack of health studies attributing adverse health effects to the measured levels. She does not know the exact levels of H_2S on her property.

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[160] Since then, the diary has secured a discharge permit from the state Department of Environmental Quality to treat its waters on site. The treatment amounts to holding ponds on adjacent farmland that the dairy purchased, and then discharging the water over their property.

[161] Refer to Health Effects Chart.

She also experiences headaches, balance problems, concentrations problems, eye irritation, problems sleeping, and general pain. The headaches are a daily occurrence, but the severity changes. If she leaves town for several days, the headaches stop. Other problems are low muscle strength, trouble walking, problems with memory retention and reading comprehension, and hypersensitivity of the skin. She believes some of her problems are due to sexual contact with her husband, who had been routinely exposed to much higher levels at the workplace, as high as 200 ppm on one occasion, according to a police report of the accident. Specialists have diagnosed her husband with brain damage and physical damage to the neurological and muscular system from exposure to hydrogen sulfide.

Her symptoms prompted her to seek medical help on many occasions. Because of her low muscle strength, one doctor initially diagnosed her with multiple sclerosis. He later changed the diagnosis to chemical encephalopathy along with peripheral neuropathy. Another doctor has diagnosed her with cystic fibrosis, and she is awaiting results from a breast tissue biopsy. She has experienced immune system disorders and her blood tests show abnormalities that no one can explain. Other people in the area have similar blood problems.

Story 3

A couple in their mid-40s lived for eleven years in a rural Colorado area of farmland, orchards, trees, and country roads. They have since moved from that location because of the myriad health problems they were experiencing. A natural gas well was situated directly across the street, less than a thousand feet from their residence. There were other gas wells close to their property, including several on the mountainside nearby, where they could see many being flared. On that mountainside, there was also a big pit containing wastewater.

The property was situated amidst hills and mountains, and it was often very windy. They continually smelled a rotten egg odor from the well across the street, which caused them to complain to the company that was doing the drilling. At first, the company was responsive, shutting the well off for a few days, draining the tanks, and then turning the rig back on. Soon, however, the couple would notice the smell again, complain, and the company would again shut off the well, drain the tanks, then eventually turn them back on. After a year and a half, the company was no longer as responsive to their complaints or as prompt to take action.

There was flaring for many weeks at both gas wells. According to the husband, the company received several citations for illegal flaring. As a result of the their complaints, the company eventually removed one of the tanks. The company told them that they were smelling sour gas and that they had nothing to worry about. In addition to the smell, they were disturbed by the noise from the well. On many occasions, they would leave for the weekend to escape the noise and the odors.

The couple believe that they were continually exposed to hydrogen sulfide for eleven years from the gas well directly across the street and from a well on an adjacent plot. They did not know what they were exposed to until 2005, but based on information they have since gathered and on professional medical assessments, they believe it was hydrogen sulfide all along. They do not know to what concentrations they were exposed.

The couple experienced health problems, which they now attribute to ongoing exposure to hydrogen sulfide. The wife, who spent more time at home, experienced and continues to experience more and worse symptoms than her husband, who would leave the house during the week for work. Specifically, the wife, who had always been healthy before the gas wells started operating near their residence, experienced pains similar to severe rheumatoid arthritis, though tests did not reveal its presence in her body. She nevertheless took medication for nine years, which did not help with her pain. She also experienced blistering of the skin when showering, severe burns on the bottoms of her feet, and her skin was covered in welts. Her entire body was swollen and her throat burned. She spent months sleeping and vomiting. She also suffered from severe sinus headaches, and both husband and wife experienced rectal bleeding, as did some of their neighbors.

After moving, the wife's arthritis symptoms relaxed, but she still sleeps a lot, and undergoes spells of vomiting. Her body experienced symptoms of detoxification after moving. Eventually, her gall bladder was removed, and showed symptoms of poisoning. By this time, she had lost over 50 pounds and was malnourished. Her gall bladder was enlarged to the size of a small pineapple, and had excessive scar tissue, which the doctor attributed to toxicity. She has been experiencing one especially disturbing, and puzzling, behavior, which started after the couple moved away from their old residence near the gas wells. Although she was born and raised in Southern California and English is her native language, she now speaks with a strange, heavy accent, which at times resembles Russian, German, or Swedish. Because of the many persistent heath problems, she is no longer considered ‘insurable’ by medical insurance companies, nor is she able to work. She is now on permanent Social Security disability.

In addition to their health problems, the couple believe hydrogen sulfide in the air around their former residence is responsible for causing the metal siding on their house to peel just two years after installation, although it was supposed to last for 50 years. Further, animals on their property experienced health problems. Two baby llamas died from a pneumonia-type illness, and an older llama had severe sinus problems. They put their dogs to sleep because of tumors. They tried to breed miniature poodles, but all the dogs were sterile.

Story 4

In October 2004, a couple in their mid-60s retired to a poor rural county in Texas, a known region of sour gas. There are several sour gas wells near their residence. Since March 2005, their property has been surrounded by several wells, all within one mile of their house, with one well across the street and less than a quarter of a mile away. Additionally, an amine gas treating plant where sour gas is sweetened, which also began operating in March 2005, is a half mile from their residence. According to a public record document that the wife received from the state environmental department in response to one of her complaints, “The facility receives sour natural gas and treats the gas with an amine treater to remove CO_2 and H_2S.”[162]

The couple believe they are exposed to hydrogen sulfide from the amine plant and the sour wells that surround their property and that their exposure is ongoing. They have noticed that odors are worse at night. They are convinced that there are hydrogen sulfide

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[162] Personal communication, February 27, 2006.

emissions because of the fact that the region is know for sour gas, because the amine plant's purpose is to sweeten sour gas, and because they have read a permit from the state allowing the amine plant to emit up to four pounds of H_2S per hour into the air. They often notice a strong rotten egg odor, as well as other chemical smells, including a sweet smell. (The latter may be due to benzene, or to high levels of H_2S, which has been reported to produce a sickening, sweet smell in concentrations above 30 ppm.[163]) The couple acknowledge that there are other pollutants emitted into the air that they do not know about. There has been no monitoring done on their property, and they do not know to what concentrations they are exposed.

Both husband and wife have experienced a host of adverse health effects since the gas wells and the amine plant began operating. Though neither smokes, nor ever has, they are both experiencing a chronic sore throat. Their other symptoms include congestion, coughing, headaches, swollen eyes, insomnia, occasional nosebleeds, and a general lack of energy. The husband's face burns, as do his hands and eyes. The wife has experienced heart palpitations and is now on heart medication, though she was entirely healthy before moving. They have both seen doctors many times because of their problems, including several visits to the emergency room, but neither has been officially diagnosed with hydrogen sulfide exposure. However, they think this is due to the general lack of knowledge about the subject.

On many occasions, they have been awakened by rotten egg fumes that choked, and burned their eyes, nose, and throat, and made them feel dizzy. At these times, they

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[163] Snyder, Jack W., MD, PhD. et al. 1995. "Occupational Fatality and Persistent Neurological Sequelae After Mass Exposure to Hydrogen Sulfide." *American Journal of Emergency Medicine*. p. 200.

leave the house and stay in a hotel, and now have a packed suitcase ready in case they need to evacuate in a hurry.

Story 5

A New Mexico couple in their late 40s live a quarter to a half mile from a municipal wastewater treatment facility, which has been receiving wastewater from an oil refinery since 1992. The oil refinery itself is four miles from the couple's residence, and there are several oil fields in the vicinity. The refinery has been there since the 1970s, but until 1992, it injected its wastewater into the ground. The wastewater facility used to receive water from a dairy operation as well.

At their residence, the couple are routinely exposed to hydrogen sulfide, which emanates from the water at the treatment facility. The husband used to work at the wastewater treatment facility, so he was exposed to H_2S more frequently, and to higher concentrations than his wife. Accordingly, his symptoms are much more severe. The couple own an H2S monitor, which sounds an alarm at 10 ppm, a daily occurrence inside and outside the house, and while driving in town. A monitor within the gates of the wastewater facility in the past registered 375 ppm, prompting the facility to be temporarily shut down. Additionally, staff from the Centers for Disease Control (CDC) were in the area for six weeks, studying hydrogen sulfide. They placed two monitors on the couple's property, and although the official results are not yet ready, the CDC staff acknowledged that conditions are bad.

The husband's blood tests showed abnormally high levels of H2S, levels so high that the examining physician thought the sample was from a deceased man. Doctors have also confirmed that the wife has been exposed to hydrogen sulfide. The husband's health has been deteriorating since 1992, when the refinery started discharging wastewater into the municipal wastewater treatment facility. His symptoms include nosebleeds, headaches, burning eyes, throat itching, itching all over his body, severe headaches, and severe rashes. His skin burns when he sweats. His teeth have been damaged, and he has suffered nerve damage and slurred speech. The wife has experienced rapidly deteriorating eyesight, ringing in her ears, memory problems, has had her gall bladder removed, and, since 1995, has trouble with balance, tremors, trouble walking up and down stairs, and severe migraine headaches.

Both have been examined by several H_2S specialists, and both have been diagnosed with chemical encephalopathy. Each time they are tested, the results are worse. The husband is permanently and totally disabled, and is on Social Security disability.

Story 6

This interviewee lived on a 640 acre farm in a relatively flat prairie areas with some undulating hills in Alberta, Canada. A natural gas well said to contain one percent hydrogen sulfide was situated about a third of a mile from the residence. There were other gas wells in the vicinity of her property, and gas was piped from these wells to a site about a mile away, where it was flared. Within three miles from the residence, there were at least a dozen natural gas wells, all with hydrogen sulfide content of one percent. There was also a battery three miles away.

Her first serious exposure occurred as a result of flaring during an initial test soon after the closest well to her house was drilled. The flaring created a jet plane-like sound, shaking the house. At this time, she experienced a headache and felt extremely sick. Her

20-year-old son, who was out walking in the field when the incident occurred, experienced knockdown. He staggered into the house, lost his balance, and collapsed. His skin was a greenish gray color when he collapsed. She contacted a regulatory body, which asked the company to stop operations. However, next day the wells were operating again. This flaring continued for a week, continually exposing her and her family to H2S. She smelled the rotten egg odor of hydrogen sulfide, and the company told her that 1 ppm of H2S was blowing to the residence. They continued to smell H2S several times per week. There has been no monitoring to determine the exact concentrations of H2S at her residence.

Within a month of the acute exposure, she was experiencing extreme fatigue, confusion, anxiety, heart symptoms, shaking and tremors, dizziness, headaches, nosebleeds, memory and cognitive impairments. Exposure to H2S or other chemicals would aggravate many of her symptoms. She also has bronchial asthma symptoms though she has never smoked. Her son developed heart arrhythmia, balance problems, and pneumonia three months after the knockdown. He now walks with a cane, experiences extreme headaches, confusion, ongoing heart problems, skin conditions including psoriasis, and burning in his lungs when exposed to chemicals. Both the interviewee and her son have multiple chemical sensitivities. An H2S specialist has diagnosed them with non-recoverable chemical encephalopathy.

Other people in the area have experienced respiratory problems, and there have been many effects on animals, including abortions and cattle's hooves falling off.

Story 7

A 27 year-old interviewee lived half a mile from a gas plant, and a little over half a mile from several oil wells with flares. He has since moved to another residence in the same Alabama county, where over 500 oil and gas are active, and he is still exposed to hydrogen sulfide.

He is convinced that he is continually exposed to hydrogen sulfide because of the presence of the rotten egg odor. The results of a monitoring project at his residence confirm the presence of H2S in concentrations of 10 ppb.[164] In addition to his ongoing exposure, the interviewee recalls nearly experiencing knockdown on one occasion while driving by a sour gas plant about five miles from his former residence. The source of that exposure was a flare at the plant, but the concentration of hydrogen sulfide is not known. At that time, he experienced shortness of breath and felt very near unconsciousness.

When he first moved to his previous residence, he started experiencing blurred vision and a loss of energy. His current health problems consist of brain fog, memory impairment, excessive sleepiness, and a lack of energy and strength. He has also experienced diarrhea, blood in his urine, loss of libido, abnormal heart rhythm, and anxiety-like attacks. Sometimes, he experiences severe and protracted involuntary muscle movements in his arms and legs that last up to a day. Exposure to hydrogen sulfide aggravates his existing symptoms. Since moving to the new residence, his heart symptoms have lessened.

He has seen several doctors about his health problems. One doctor diagnosed him with optic nerve damage, and another with chemical encephalopathy. He has tested

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[164] Monitoring done by Lisa Sumi, Research Director, Oil and Gas Accountability Project. August 2005, using Jerome 631 H2S monitor. Data used with permission.

negative for a host of diseases, including Parkinson’s. Though he is 27, he said he feels 67, and that not a day goes by when he feels normal.

Cats at his old residence were also affected. They experienced vomiting and weight loss, and exhibited sexually confused behavior.

Story 8:

This interviewee, a woman in her 50s, is in the process of moving to eastern Texas from her western Colorado home, where she has lived for ten years and worked as an irrigator. There are two natural gas wells about a mile downwind of her residence, and a shut in well across the street. Flaring and open condensate pits were common at these wells.

Although this interviewee experienced symptoms at her residence, her primary exposure to hydrogen sulfide was while she was working in the area, because many wells dot the fields she was irrigating. She started working near the gas wells in March 2005. One well pad was very close to the inlet for the irrigation water. Within a month, she began experiencing burning and swelling in her nasal passages. Several treatments with antibiotics did not clear her symptoms, and her doctor conceded that he did not know what was causing her problems. After this experience, she began wearing a charcoal filter mask.

Her single major exposure, which resulted in a knockdown, occurred one evening when she was getting out of her truck to turn off the irrigation water. She was approximately 50 feet from the well, when she experienced a blinding headache that made her feel like her head would burst. She then started to collapse and black out. She caught the door of her truck and was dangling there for about five minutes. Her headache then abated and she started to smell the rotten egg odor of hydrogen sulfide, though she did not smell it when the headache started.

Since the knockdown, this interviewee has developed chemical sensitivities, and her doctor has advised her to move. She requires a respirator to be outside, and even with the respirator, she can only be outside for about an hour. She has installed three air scrubbers to purify the air in her house.

She experiences burning around her eyes and on the exposed skin on her face. Her sinuses burn and itch, and she frequently gets nosebleeds. If she is outside for more than an hour, even with the respirator, she develops ulcers on her tongue and in her mouth, and eventually the glands in her neck and armpits swell. If she ignores these symptoms, she gets nauseated and experiences vomiting and explosive diarrhea. She also has nerve inflammation in her legs, and her balance and short term memory are impaired.

The source of hydrogen sulfide, she believes, are fugitive emissions from the wells, and especially from open condensate tanks. A stack flare was also operating within a mile of her house. No tests have been done to confirm the presence of hydrogen sulfide.

Other people in her area have also been affected. One neighbor has been feeling nauseated, while many people smell the odors from the wells and have upper respiratory infections. The interviewee’s new mule, which grazes on land near the wells, has experienced hair falling out. A horse also had his mane thin out and experienced diarrhea during flaring. The horse’s hooves fell apart and would not heal, so the interviewee had him put down.

HYDROGEN SULFIDE:
EVALUATION OF CURRENT CALIFORNIA AIR QUALITY STANDARDS WITH RESPECT TO PROTECTION OF CHILDREN

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A. Extended abstract

The current California Ambient Air Quality Standard (CAAQS) for hydrogen sulfide is 0.03 ppm (30 ppb, 42 $\mu g/m^3$) for one hour. The standard was adopted in 1969 and was based on the geometric mean odor threshold measured in adults. The purpose of the standard was to decrease odor annoyance. The standard was reviewed in 1980 and 1984 (CARB, 1984), and was not changed since no new relevant information had emerged. The U.S. EPA presently does not classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant. However, several countries have short-term (usually 30 minute) standards for hydrogen sulfide, as well as long-term (24 hour) standards.

This report focuses on key studies in humans and animals bearing on the health-protectiveness of the CAAQS for hydrogen sulfide. It also includes a discussion of whether significant adverse health effects would reasonably be expected to occur, especially among infants and children, at exposure concentrations below the CAAQS of 30 ppb, based on the findings of published studies. Additional research on odor sensitivity in infants, children, and adults would be useful in evaluating the standard. This would include: (1) testing of the odor threshold for H_2S using the most current methodology among groups of healthy persons of both sexes in different age ranges; (2) odor testing of hydrogen sulfide in adolescents or younger children to determine their odor threshold for H_2S; (3) the identification of children hypersensitive to the odor of hydrogen sulfide; and (4) physiologic testing of anosmic (either specifically anosmic to H_2S or totally anosmic) children at the CAAQS to determine if adverse physiological symptoms occur in the absence of odor detection.

B. Background

The Mulford-Carrell Air Resources Act of 1967 directed the Air Resources Board to divide California into Air Basins and to adopt ambient air quality standards for each basin (Health and Safety Code (H&SC) Section 39606). The existing California state-wide ambient air quality standard (CAAQS) for hydrogen sulfide of 0.03 ppm (30 ppb, 42 $\mu g/m^3$), averaged over a period of 1 hour and not to be equaled or exceeded, protects against nuisance odor ("rotten egg smell") for the general public. The standard was adopted in 1969 and was based on rounding of the geometric mean odor threshold of 0.029 ppm (range = 0.012 – 0.069 ppm; geometric SD = 0.005 ppm) measured in adults (California State Department of Public Health, 1969). The standard was reviewed by the Department of Health Services in 1980 and 1984, and was not changed since no new relevant information had emerged. OEHHA (1999) formally adopted 30 ppb as the acute Reference Exposure Level (REL) for use in evaluating peak off-site concentrations from industrial facilities subject to requirements in H&SC Section 44300 *et seq*. OEHHA (2000) adopted a level of 8 ppb (10 $\mu g/m^3$) as the chronic Reference Exposure Level (cREL) for use in evaluating long term emissions from Hot Spots facilities. The cREL was based on a study demonstrating nasal histological changes in mice.

At the federal level, U.S. EPA does not currently classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant (HAP). U.S. EPA has developed a (chronic) Reference Concentration (RfC) of 0.001 mg/m^3 (1 $\mu g/m^3$) for hydrogen sulfide (USEPA, 1999). The RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.

There are no international standards for H_2S. Many countries have "short-term" (usually 30 minute) standards, which range from 6 to 210 ppb (WHO, 1981). The World Health Organization (WHO) recommends that, in order to avoid substantial complaints about odor annoyance among the exposed population, hydrogen sulfide concentrations should not be allowed to exceed 0.005 ppm (5 ppb; 7 $\mu g/m^3$), with a 30-minute averaging time (WHO, 1981; National Research Council, 1979; Lindvall, 1970). A very short-lived, peak concentration could also be annoying. Rule 2 of Regulation 9 of the Bay Area Air Quality Management District (BAAQMD) specifies that ambient ground level H_2S concentrations may not exceed 60 ppb averaged over 3 consecutive minutes. Regulating at averaging times less than 30 – 60 minutes may be difficult. Many countries have "long-term" (24 hour) standards (WHO, 1981).

NRC (1979), WHO (1981), Beauchamp *et al*. (1984), Reiffenstein *et al*. (1992), and ATSDR (1999) have published reviews of the health effects of hydrogen sulfide.

C. Principal sources/Exposure assessment

Hydrogen sulfide (H_2S) is used as a reagent and as an intermediate in the preparation of other reduced sulfur compounds (HSDB, 1999). It is also a by-product of desulfurization processes in the oil and gas industries and rayon production, sewage treatment, and leather tanning (Ammann, 1986). Geothermal power plants, petroleum production and refining, and sewer gas are specific sources of hydrogen sulfide in California. The annual statewide industrial emissions from facilities reporting under the Air Toxics Hot Spots Information and Assessment Act in California (H&SC Sec. 44300 *et seq*.), based on the most recent inventory, were estimated to be 5,688,172 pounds of hydrogen sulfide (CARB, 1999).

A specific concern in California has been schools located near workplaces emitting toxic substances. For example, the Hillcrest Elementary School in Rodeo (Contra Costa County; part of the BAAQMD) is adjacent to an oil refinery which, on occasion, has emitted enough malodorous sulfur compounds (including H_2S) for the school to close its doors and for the teachers and children to "shelter-in-place." Thus the school district has planned to relocate the school (West County Times, November 23, 1999). These compounds have also affected other schools in the area.

Hydrogen sulfide is produced endogenously in mammalian tissues from L-cysteine, mainly by two pyridoxal-5'-phosphate-dependent enzymes, cystathionine beta-synthetase and cystathionine gamma-lyase (Hosoki *et al*., 1997). Abe and Kimura (1996) suggested that hydrogen sulfide may be an endogenous neuromodulator in the hippocampus based on the high level of cystathionine beta-synthetase in the hippocampus and on experimental effects of activators and inhibitors of the enzyme.

D. Key studies of acute and chronic health impacts

D.1. Toxicity to Humans

D.1.1. Adults. Hydrogen sulfide is an extremely hazardous gas (ACGIH, 1991). Exposure to high concentrations of hydrogen sulfide is reported to be the most common cause of sudden death in the workplace (NIOSH, 1977). Estimates of the mortality resulting from acute hydrogen sulfide intoxication include 2.8% (Arnold *et al*., 1985) and 6% (WHO, 1981). While severe intoxication is especially of concern when exposure occurs in confined spaces, an accidental release of hydrogen sulfide into the ambient air surrounding industrial facilities can cause very serious effects. As a result of an accidental release of hydrogen sulfide due to a malfunctioning flare at an oilfield at Poza Rica, Mexico in 1950, 320 people were hospitalized and 22 died (WHO, 1981).

Most information on H_2S toxicity comes from studies that used levels of H_2S orders of magnitude above the standard of 0.03 ppm. Hazardtext (1994) reported an inhalation LC_{Lo} of 600 and 800 ppm (840 and 1,120 mg/m^3) for 30 and 5 minutes, respectively. A lethal exposure was documented for a worker exposed to approximately 600 ppm H_2S for 5 to 15 minutes (Simson and Simpson, 1971). Inhalation of 1,000 ppm (1,400 mg/m^3) is reported to cause immediate respiratory arrest (ACGIH, 1991). Concentrations greater than 200 ppm (280 mg/m^3) H_2S are reported to cause direct irritant effects on exposed surfaces and can cause pulmonary edema following longer exposures (Spiers and Finnegan, 1986). The mechanism of H_2S

toxicity, cellular hypoxia caused by inhibition of cytochrome oxidase, is similar to that for cyanide. Toxicity can be treated by induction of methemoglobin or by therapy with hyperbaric oxygen (Elovaara *et al*., 1978; Hsu *et al*., 1987).

At concentrations exceeding 50 ppm (70 mg/m³) H_2S, olfactory fatigue prevents detection of H_2S odor. Exposure to 100-150 ppm (140-210 mg/m³) for several hours causes local irritation (Haggard, 1925). Exposure to 50 ppm for 1 hour causes conjunctivitis with ocular pain, lacrimation, and photophobia; this can progress to keratoconjunctivitis and vesiculation of the corneal epithelium (ACGIH, 1991).

Bhambhani and Singh (1985) reported that exposure of 42 individuals to 2.5 to 5 ppm (3.5 to 7 mg/m³) H_2S caused coughing and throat irritation after 15 minutes. Bhambhani and Singh (1991) showed that 16 healthy adult male subjects (25.2±5.5 years old) exposed to 5 ppm (7 mg/m³) H_2S under conditions of moderate exercise exhibited impaired lactate and oxygen uptake in the blood. Subsequently Bhambani *et al*. (1994) compared the effects of inhaling 5 ppm H_2S on physiological and hematological responses during exercise. Subjects were 13 men (mean±SD for age, height, and weight = 24.7±4.6 y, 173±6.6 cm, and 73.1±8.1 kg, respectively) and 12 women (mean±SD = 22.0±2.1 y, 165±8.2 cm, and 63.4±8.6 kg, respectively). Subjects completed two 30-minute exercise tests on a cycle ergometer at 50% of their predetermined maximal aerobic power, while breathing either air or 5 ppm H_2S. There were no significant differences between the two exposures for metabolic (oxygen uptake, carbon dioxide production, respiratory exchange ratio), cardiovascular (heart rate, blood pressure, rate pressure product), arterial blood (oxygen and carbon dioxide tensions, pH), and perceptual (rating of perceived exertion) responses. No one reported adverse health effects following H_2S exposure. The authors believe that healthy adults can safely perform moderate intensity work in environments containing 5 ppm H_2S.

Bhambhani *et al*. (1996) examined the acute effects of “oral” inhalation of 10-ppm H_2S, the occupational exposure limit, on lung physiology as measured by pulmonary function in nine men and ten women. The volunteers inhaled medical air or 10 ppm H_2S through the mouth for 15 minutes each during cycle exercise at 50% of their maximal aerobic power. Routine pulmonary function tests (FVC, FEV_1, FEV_1/FVC, PEFR, maximal ventilation volume, and DL_{CO}) were administered at rest and immediately after the two exposure conditions. There were no significant changes in any of the variables derived from the flow volume loop, maximum ventilation volume, and diffusion capacity of the lung for carbon monoxide (DL_{CO}) in both genders. No subject experienced any sign or symptom as a result of H_2S. The authors concluded that inhalation of 10 ppm H_2S through the mouth at an elevated metabolic and ventilation rate does not significantly alter pulmonary function in healthy people.

Jappinen *et al*. (1990) exposed ten adult asthmatic volunteers to 2 ppm H_2S for 30 minutes and tested pulmonary function. All subjects reported detecting “very unpleasant” odor but “rapidly became accustomed to it.” Three subjects reported headache following exposure. No significant changes in mean FVC or FEV_1 were reported. Although individual values for specific airway resistance (SR_{aw}) were not reported, the difference following exposure ranged from –5.95% to +137.78%. The decrease in specific airway conductance, SG_{aw}, ranged from –57.7% to +28.9%. The increase in mean SR_{aw} and the decrease in mean SG_{aw} were not statistically significant for the entire group. However, markedly (>30%) increased airway resistance and decreased airway conductance were noted in two of the ten asthmatic subjects at 2 ppm, which indicated bronchial obstruction and may be clinically important. Two ppm is 67 times the CAAQS of 0.03 ppm.

Hydrogen sulfide is noted for its strong and offensive odor. The existing CAAQS of 0.03 ppm (30 ppb, 42 $\mu g/m^3$) for 1 hour is based on rounding the geometric mean odor detection threshold of 0.029 ppm (range = 0.012 – 0.069 ppm; GSD = 0.005 ppm). The threshold was determined for a panel of 16 presumably healthy adults (California State Department of Public Health, 1969). No information on the sex or age of the panel members has been located. Amoore (1985) reviewed 26 studies, published between 1848 and 1979, all of which reported average odor detection thresholds for H_2S. The 26 studies seem to be mainly controlled exposures and used various measurement methods. They included (1) at least two studies using only one subject, (2) a study of a panel of 35 people testing odors in natural gas in Southern California, and (3) another study of 852 untrained young adults (age range = 17.5 – 22.4 years) tested at county and state fairs in the Northwest. The average odor detection threshold in the 26 studies ranged from 0.00007 to 1.4 ppm H_2S. The geometric mean of the 26 studies was 0.008 ppm (8 ppb), approximately one-fourth the value determined by the Department of Public Health and lower than the lowest individual threshold of 12 ppb measured in the California panel. Surprisingly the Department of Public Health panel study was <u>not</u> one of the 26 studies used by Amoore and was not even mentioned in his 1985 report to the ARB.

Venstrom and Amoore (1968) reported that, in general, olfactory sensitivities decrease by a factor of 2 for each 22 years of age above age 20. The conclusion was based on a study of 18 odorants in 97 government laboratory workers, ages 20 through 70. Hydrogen sulfide was not tested. The geometric mean odor threshold of 8 ppb for H_2S from the 26 studies is based on an average age of 40 (possibly assumed to be the age of an average adult). Amoore (1985) estimated that an 18-year-old person would have a threshold of 4 ppb H_2S, while a 62-year-old person was predicted to have a threshold of 16 ppb. Amoore also stated that there was no noticeable trend of odor sensitivity between young adults and children down to 5 years but did not present specific data to support the statement.

Concentrations, which substantially exceed the odor threshold for, result in the annoying and discomforting physiological symptoms of headache or nausea (Amoore, 1985; Reynolds and Kauper 1984). The perceived intensity of the odor of H_2S depends on the longevity of the concentration, and the intensity increases 20% for each doubling of the concentration (Amoore, 1985). Several studies have been conducted to establish the ratio of discomforting annoyance threshold to detection threshold for unpleasant odors (Winkler, 1975; Winneke and Kastka, 1977; Hellman and Small, 1974; Adams *et al.,* 1968; and NCASI, 1971). The geometric mean for these studies is 5; therefore an unpleasant odor should result in annoying discomfort when it reaches an average concentration of 5 times its detection threshold. (Two studies that tested only H_2S had a geometric mean of 4.) Applying the 5-fold multiplier to the mean detectable level of 8 ppb results in a mean annoyance threshold of 40 ppb. Amoore (1985) estimates that at 30 ppb, the CAAQS, H_2S would be detectable by 83% of the population and would be discomforting to 40% of the population (Table 1). These "theoretical" estimates have been substantiated by odor complaints and reports of nausea and headache (Reynolds and Kauper 1984) at 30 ppb H_2S exposures from geyser emissions.

In order to avoid substantial complaints about odor annoyance among the exposed population, the World Health Organization (WHO) recommends that hydrogen sulfide concentrations should not exceed 0.005 ppm (5 ppb; 7 $\mu g/m^3$), with a 30-minute averaging time (WHO, 1981; National Research Council, 1979; Lindvall, 1970). The WHO task group believed that 5 ppb averaged over 30 minutes "should not produce odour nuisance in most situations."

Table 1. Predicted effects of exposure to ambient H_2S. (Adapted from Amoore, 1985)

H_2S (ppb)	% able to detect odor[a]	Perceived odor intensity[b] (ratio)	Median odor units[c]	% annoyed by odor[d]
200	99	2.31	25	88
100	96	1.93	12	75
50	91	1.61	6.2	56
40	88	1.52	5.0	50
35	87	1.47	4.4	47
30 (CAAQS)	83	1.41	3.7	40
25	80	1.34	3.1	37
20	74	1.27	2.5	31
15	69	1.18	1.9	22
10	56	1.06	1.2	17
8	50	1.00	1.00	11
6	42	0.93	0.75	8
4	30	0.83	0.50	5
2	14	0.70	0.25	2
1	6	0.58	0.12	1
0.5	2	0.49	0.06	0

[a] Based on mean odor detection threshold of 8.0 ppb and SD±2.0 binary steps

[b] Based on intensity exponent of 0.26 (Lindvall, 1974).

[c] H_2S concentration divided by mean odor detection threshold of 8 ppb.

[d] Based on assumption that mean annoyance threshold is 5x the mean odor detection threshold, and SD±2.0 binary steps.

Kilburn and Warshaw (1995) investigated whether people exposed to sulfide gases, including H_2S, as a result of working at or living downwind from the processing of "sour" crude oil demonstrated persistent neurobehavioral dysfunction. They studied 13 former workers and 22 neighbors of a California coastal oil refinery who complained of headaches, nausea, vomiting, depression, personality changes, nosebleeds, and breathing difficulties. Neurobehavioral functions and a profile of mood states were compared to 32 controls matched for age and educational level. The exposed subjects' mean values were statistically significantly different (abnormal) compared to controls for several tests (two-choice reaction time; balance (as speed of sway); color discrimination; digit symbol; trail-making A and B; immediate recall of a story). Their profile of mood states (POMS) scores were much higher than those of controls. Test scores for anger, confusion, depression, tension-anxiety, and fatigue were significantly elevated and nearly identical in both exposed residents and former workers, while the scores for controls equaled normal values from other published studies. Visual recall was significantly impaired in neighbors, but not in the former workers. Limited off-site air monitoring (one week) in the neighborhood found average levels of 10 ppb H_2S (with peaks of 100 ppb), 4 ppb dimethylsulfide, and 2 ppb mercaptans. On-site levels were much higher. The authors concluded that neurophysiological abnormalities were associated with exposure to reduced sulfur gases, including H_2S from crude oil desulfurization.

D.1.2. Children. In a case report Gaitonde *et al*. (1987) described subacute encephalopathy, ataxia, and choreoathetoid (jerky, involuntary) responses in a 20-month-old child with long term (approximately one year) exposure to hydrogen sulfide from a coal mine. Levels of up to at least 0.6 ppm (600 ppb) were measured and levels were possibly higher before measurements started. The abnormalities resolved after the emission source ceased operation.

As part of the South Karelia Air Pollution Study in Finland (Jaakkola *et al*., 1990), Marttila *et al*. (1994) assessed the role of long-term exposure to ambient air malodorous sulfur compounds released from pulp mills as a determinant of eye and respiratory symptoms and headache in children. The parents of 134 children living in severely polluted (n = 42), moderately polluted (n = 62), and rural, non-polluted (n = 30) communities responded to a cross-sectional questionnaire (response rate = 83%). In the severely polluted area, the annual mean concentrations of hydrogen sulfide and methyl mercaptan (H_3CSH) were estimated to be 8 $\mu g/m^3$ (6 ppb) and 2 - 5 $\mu g/m^3$ (1.4 – 3.6 ppb), respectively. The highest daily average concentrations were 100 $\mu g/m^3$ (71 ppb) and 50 $\mu g/m^3$ (36 ppb), respectively. The adjusted odds ratios (OR) for symptoms experienced during the previous 4 weeks and 12 months in the severely versus the non-polluted community were estimated in logistic regression analysis controlling for age and gender. The risks of nasal symptoms, cough, eye symptoms, and headache were increased in the severely polluted community, but did not reach statistical significance (Table 2). In addition, OEHHA staff noted that the highest percentages of children with symptoms were in the moderately polluted community, not in the severely polluted community. The authors concluded that exposure to malodorous sulfur compounds may affect the health of children. The odor threshold for methyl mercaptan of 1.6 ppb (Amoore and Hautala, 1983) indicates that it also likely contributed to the odor and probably the symptoms.

Table 2. Symptoms Reported in Marttila *et al*. (1994)

Symptom	*Time*	*Odds Ratio*	*95% CI*	*Time*	*Odds ratio*	*95%CI*
nasal symptoms	4 weeks	1.40	0.59-3.31	12 months	2.47	0.93-6.53
cough	4 weeks	1.83	0.75-4.45	12 months	2.28	0.95-5.47
eye symptoms	NR	NR	NR	12 months	1.15	0.43-3.05
headache	NR	1.02	0.36-2.94	12 months	1.77	0.69-4.54

NR = not reported

Studies of controlled exposures in children to study H_2S odor detection have not been located. A recent report studying children concluded that children aged 8 to 14 years have equivalent odor sensitivity to young adults (Cain *et al*., 1995), although children lack knowledge to identify specific odors by name. Koelega (1994) found that prepubescent children (58 nine-year-olds) were inferior in their detection of 4 of 5 odors compared to 15-year-olds (n = 58) and 20-year-olds (n = 112). Schmidt and Beauchamp (1988) have even tested 3-year-olds (n = 16) for sensitivity to noxious chemicals, such as butyric acid and pyridine.

In March-April 1983, 949 cases (including 727 in adolescent females) of acute non-fatal illness consisting of headache, dizziness, blurred vision, abdominal pain, myalgia, and fainting occurred at schools on the West Bank. However, physical examinations and biochemical tests were normal. There was no common exposure to food, drink, or agricultural chemicals among those affected. No toxins were consistently present in patients' blood or urine. The only environmental toxicant detected was H_2S gas in low concentrations (40 ppb) in a schoolroom at the site of the first outbreak (from a faulty latrine in the schoolyard). The illness was deemed to be psychogenic and possibly triggered by the smell of H_2S (Landrigan and Miller , 1983; Modan *et al*., 1983).

D.1.3. Development. Xu *et al*. (1998) conducted a retrospective epidemiological study in a large petrochemical complex in Beijing, China in order to assess the possible association between petrochemical exposure and spontaneous abortion. The facility consisted of 17 major production plants divided into separate workshops, which allowed for the assessment of exposure to specific chemicals. Married women (n = 2,853), who were 20-44 years of age, had never smoked, and who reported at least one pregnancy during employment at the plant, participated in the study. According to their employment record, about 57% of these workers reported occupational exposure to petrochemicals during the first trimester of their pregnancy. There was a significantly increased risk of spontaneous abortion for women working in all of the production plants with frequent exposure to petrochemicals compared with those working in non-chemical plants. Also, when a comparison was made between exposed and non-exposed groups within each plant, exposure to petrochemicals was consistently associated with an increased risk of spontaneous abortion (overall odds ratio (OR) = 2.7 (95% confidence interval (CI) = 1.8 to 3.9) after adjusting for potential confounding factors). Using exposure information obtained from interview responses for (self-reported) exposures, the estimated OR for spontaneous abortions was 2.9 (95% CI = 2.0 to 4.0). When the analysis was repeated by excluding 452 women who provided inconsistent reports between recalled exposure and work history, a comparable risk of spontaneous abortion (OR 2.9; 95% CI = 2.0 to 4.4) was found. In analyses for exposure to specific chemicals, an increased risk of spontaneous abortion was found with exposure to most chemicals. There were 106 women (3.7% of the study population) exposed only to hydrogen sulfide; the results for H_2S (OR 2.3; 95% CI = 1.2 to 4.4) were statistically significant. Unfortunately H_2S exposure concentrations were not reported.

D.2. Effects of Animal Exposure

D.2.1. Adult/mature animals. A median lethal concentration (LC_{50}) in rats exposed to H_2S for 4 hours was estimated as 440 ppm (616 mg/m³) (Tansy *et al*., 1981). An inhalation LC_{Lo} of 444 ppm for an unspecified duration is reported in rats, and a lethal concentration of 673 ppm (942 mg/m³) for 1 hour is reported in mice (RTECS, 1994). In another study, mortality was significantly higher for male rats (30%), compared to females (20%), over a range of exposure times and concentrations (Prior *et al*., 1988). A concentration of 1,000 ppm (1,400 mg/m³) caused respiratory arrest and death in dogs after 15-20 minutes (Haggard and Henderson, 1922). Inhalation of 100 ppm (140 mg/m³) for 2 hours resulted in altered leucine incorporation into brain proteins in mice (Elovaara *et al*., 1978). Kosmider *et al*. (1967) reported abnormal electrocardiograms in rabbits exposed to 100 mg/m³ (71 ppm) H_2S for 1.5 hours.

Khan *et al*. (1990) exposed groups of 12 male Fischer 344 rats to 0, 10, 50, 200, 400, or 500-700 ppm hydrogen sulfide for 4 hours. Four rats from each group were euthanized at 1, 24, or 48 hours post-exposure. The activity of cytochrome c oxidase in lung mitochondria, a primary molecular target of H_2S, was significantly ($p<0.05$) decreased at 50 ppm (15%), 200 ppm (43%), and 400 ppm (68%) at 1-hour post-exposure compared to controls. A NOAEL of 10 ppm for inhibition of cytochrome c oxidase was identified in this study.

Fischer and Sprague-Dawley rats (15 per group) were exposed to 0, 10.1, 30.5, or 80 ppm (0, 14.1, 42.7, or 112 mg/m^3, respectively) H_2S for 6 hours/day, 5 days/week for 90 days (CIIT, 1983a,b). Measurements of neurological and hematological function revealed no abnormalities due to H_2S exposure. Histological examination of the nasal turbinates also revealed no significant exposure-related changes. A significant decrease in body weight was observed in both strains of rats exposed to 80 ppm (112 mg/m^3).

In a companion study, the CIIT conducted a 90-day inhalation study in mice (10 or 12 mice per group) exposed to 0, 10.1, 30.5, or 80 ppm (0, 14.1, 42.7, or 112 mg/m^3, respectively) H_2S for 6 hours/day, 5 days/week (CIIT, 1983c). Neurological function was measured by tests for posture, gait, facial muscle tone, and reflexes. Ophthalmologic and hematologic examinations were also performed, and a detailed necropsy was included at the end of the experiment. The only exposure-related histological lesion was inflammation of the nasal mucosa of the anterior segment of the noses of mice exposed to 80 ppm (112 mg/m^3) H_2S. Weight loss was also observed in the mice exposed to 80 ppm. Neurological and hematological tests revealed no abnormalities. The 30.5 ppm (42.5 mg/m^3) level was considered to be a NOAEL for histological changes in the nasal mucosa. (Different adjustments were made to this NOAEL by U. S. EPA to calculate the RfC of 1 μg/m^3 and by OEHHA to calculate the chronic REL of 10 μg/m^3 (8 ppb).)

Hydrogen sulfide (0, 10, 30, or 80 ppm) was administered via inhalation (6 h/d, 7 d/wk) to 10-week-old male CD rats (n = 12/group) for 10 weeks (Brenneman *et al*., 2000). Histological evaluation revealed that rats exposed to 30 or 80 ppm had significant increases in lesions of the olfactory mucosa but not other tissues. Multifocal, rostrocaudally-distributed olfactory neuron loss and basal cell hyperplasia were seen. The dorsal medial meatus and the dorsal and medial portions of the ethmoid recess were affected. The lowest dose (10 ppm) was considered a no observed adverse effect level for olfactory lesions.

Fischer F344 rats inhaled 0, 1, 10, or 100 ppm hydrogen sulfide for 8 hours/day for 5 weeks (Hulbert *et al*, 1989). No effects were noted on baseline measurements of airway resistance, dynamic compliance, tidal volume, minute volume, or heart rate. Two findings were noted more frequently in exposed rats: (1) proliferation of ciliated cells in the tracheal and bronchiolar epithelium, and (2) lymphocyte infiltration of the bronchial submucosa. Some exposed animals responded similarly to controls to aerosol methacholine challenge, whereas a subgroup of exposed rats were hyperreactive to concentrations as low as 1 ppm H_2S.

Male rats were exposed to 0, 10, 200, or 400 ppm H_2S for 4 hours (Lopez *et al.*, 1987). Samples of bronchoalveolar and nasal lavage fluid contained increased inflammatory cells, protein, and lactate dehydrogenase in rats treated with 400 ppm. Later Lopez and associates (1988) showed that exposure to 83 ppm (116 mg/m^3) for 4 hours resulted in mild perivascular edema.

D.2.2. Developing animals. Saillenfait *et al.* (1989) investigated the developmental toxicity of H_2S in rats. Rats were exposed 6 hours/day on days 6 through 20 of gestation to 100 ppm hydrogen sulfide. No maternal toxicity or developmental defects were observed.

Hayden *et al*. (1990) exposed gravid Sprague-Dawley rat dams continuously to 0, 20, 50, and 75 ppm H_2S from day 6 of gestation until day 21 postpartum. The animals demonstrated normal reproductive parameters until parturition, when delivery time was extended in a dose-dependent manner (with a maximum increase of 42% at 75 ppm). Pups exposed in utero and neonatally to day 21 postpartum developed with a subtle decrease in time of ear detachment and hair development, but with no other observed change in growth and development through day 21 postpartum.

Hannah and Roth (1991) analyzed the dendritic fields of developing Purkinje cells in rat cerebellum to determine the effects of chronic exposure to low concentrations of H_2S during perinatal development. Treatment of timed-pregnant female Sprague Dawley rats with 20 and 50 ppm H_2S for 7 hours per day from day 5 after mating until day 21 after birth produced severe alterations in the architecture and growth characteristics of the dendritic fields of the Purkinje cells. The architectural modifications included longer branches, an increase in the vertex path length, and variations in the number of branches in particular areas of the dendritic field. The treated cells also exhibited a nonsymmetrical growth pattern at a time when random terminal branching is normally occurring. Thus, developing neurons exposed to H_2S may be at risk of severe deficits. However, the lower level of 20 ppm for 7 hours is nearly 2 orders of magnitude above the present one-hour standard.

Dorman *et al*. (2000) examined the effect of perinatal exposure of H_2S on pregnancy outcomes, offspring development, and offspring behavior in rats. Male and female Sprague-

Dawley rats (12 rats/sex/concentration) were exposed to 0, 10, 30, or 80 ppm H_2S 6 h/day, 7 days/week for 2 weeks prior to breeding. Exposures continued during a 2-week mating period and then from Gestation Day (GD) 0 through GD 19. Exposure of rat dams and their pups (eight rats/litter after culling) resumed between postnatal day (PND) 5 and 18. Adult males were exposed for 70 consecutive days. Offspring were evaluated using motor activity (assessed on PND 13, 17, 21, and 60±2), passive avoidance (PND 22±1 and 62±3), functional observation battery (FOB) (PND 60±2), acoustic startle response (PND 21 and 62±3), and neuropathology (PND 23±2 and 61±2). No deaths occurred and no adverse physical signs were seen in F_0 males or females. There were no statistically significant effects on the reproductive performance of the F_0 rats as assessed by the number of females with live pups, litter size, average length of gestation, and the average number of implants per pregnant female. Exposure to H_2S did not affect pup growth, development, or performance on any behavioral test. The authors conclude that H_2S is neither a reproductive toxicant nor a behavioral developmental neurotoxicant in the rat at occupationally relevant exposure concentrations (i.e., at 10 ppm, the current occupational daily average exposure limits - TLV and PEL; however, the ACGIH is considering lowering the TLV to 5 ppm). The lowest level tested (10 ppm) is more than 300-fold higher than the CAAQS of 0.030 ppm.

E. Interactions between hydrogen sulfide and other pollutants

Ethanol can potentiate the effects of H_2S by shortening the mean time-to-unconsciousness in mice exposed to 800 ppm (1,120 mg/m³) H_2S (Beck *et al*., 1979).

Endogenous hydrogen sulfide may regulate smooth muscle tone in synergy with nitric oxide (Hosoki *et al*., 1997).

Hydrogen sulfide is often accompanied by other malodorous sulfur compounds, such as methyl mercaptan, dimethyl sulfide, and dimethyl disulfide. Some of these have odor thresholds lower than that of hydrogen sulfide. The complex mixture is often referred to as TRS (total reduced sulfur).

Lindvall (1977) reported that the perceived odor strength of H_2S is increased by the simultaneous presence of 600 ppb nitric oxide (600 ppb nitric acid is imperceptible by itself).

F. Conclusions

The current standard of 0.03 ppm (30 ppb) hydrogen sulfide for one hour based on odor is well below NOAEL levels from animal experiments where exposure lasted weeks to months, including the period of intrauterine development. However, it is greater than OEHHA's chronic Reference Exposure Level (REL) of 8 ppb, which is based on histological changes in the nasal area of mice. (The chronic REL is compared to the annual average H_2S concentration.) Ideally neither of these two benchmark levels should be exceeded by the properly averaged concentration.

Additional research might help reduce uncertainties regarding the impacts of hydrogen sulfide on the health of infants and children. This would include:

a. Odor testing of hydrogen sulfide in adolescents or younger children, if ethically permissible, to determine their odor threshold. Current data on odor detection in children are not consistent. Data on H_2S odor detection in children under controlled exposure are lacking.

b. The identification of children hypersensitive to the odor of hydrogen sulfide. While the odor from very low level H_2S would not itself threaten their physical health, the odor might be alarming to hypersensitive children. Psychosomatic complaints might be more confusing to children than to adults.

c. Physiologic testing of anosmic (either specifically anosmic to H_2S or totally anosmic) children at the CAAQS would be useful in determining whether if adverse physiological symptoms occur in the absence of odor detection.

d. Testing of the odor threshold for H_2S using the most current methodology among groups of healthy persons of both sexes in different age ranges. Data from such testing would likely be an improvement over the use of either the mean of 16 people (California Department of Public Health, 1969) or the mean from 26 studies, conducted over a period of 130 years, which found thresholds spanning a 20,000 fold range, from 0.07 ppb to 1400 ppb (Amoore, 1985). (If the highest and lowest values of the range in Amoore (1985) are dropped as outliers - Amoore (1985) stated that these two studies seemed to involve only one subject - the range would be 0.43 ppb to 190 ppb, a 440-fold range).

e. Further research is needed on the topic of when odor is an adverse health effect and how much consideration should be given to psychosomatic complaints accompanying odor annoyance (Dalton *et al*., 1997; ATS, 2000). A recent American Thoracic Society position paper titled “What Constitutes an Adverse Health Effect of Air Pollution?” (ATS, 2000) indicates that air pollution exposures, which interfere with the quality of life, can be considered adverse. This suggests that, for the purpose of setting a standard, odor-related annoyance should be considered adverse, even if nausea or headache or other symptoms are not present.

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