Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study

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[1] The multispecies analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory (BAO) in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and non-methane hydrocarbons (propane, n-butane, i-pentane, n-pentane and benzene) around BAO, a pilot study involving automobile-based surveys was carried out during the summer of 2008. A mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the alkane ratios we observe in air masses impacted by oil and gas operations in northeastern Colorado. Using the WRAP Phase III inventory of total volatile organic compound (VOC) emissions from oil and gas exploration, production and processing, together with flashing and venting emission speciation profiles provided by State agencies or the oil and gas industry, we derive a range of bottom-up speciated emissions for Weld County in 2008. We use the observed ambient molar ratios and flashing and venting emissions data to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. Our analysis suggests that the emissions of the species we measured are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two.

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1. Introduction

[2] Since 2004, the National Oceanic and Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) has increased its measurement network density over North America, with continuous carbon dioxide (CO_2) and carbon monoxide (CO) measurements and daily collection of discrete air samples at a network of tall towers (A. E. Andrews et al., manuscript in preparation, 2012) and bi-weekly discrete air sampling along vertical aircraft profiles (C. Sweeney et al., manuscript in preparation, 2012). Close to 60 chemical species or isotopes are measured in the discrete air samples, including long-lived greenhouse gases (GHGs) such as CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), tropospheric ozone precursors such as CO and several volatile organic compounds (VOCs), and stratospheric-ozone-depleting substances. The NOAA multispecies regional data set provides unique information on how important atmospheric trace gases vary in space and time over the continent, and it can be used to quantify how different processes contribute to GHG burdens and/or affect regional air quality.

[3] In this study we focus our analysis on a very strong alkane atmospheric signature observed downwind of the Denver-Julesburg Fossil Fuel Basin (DJB) in the Colorado Northern Front Range (Figure 1 and auxiliary material

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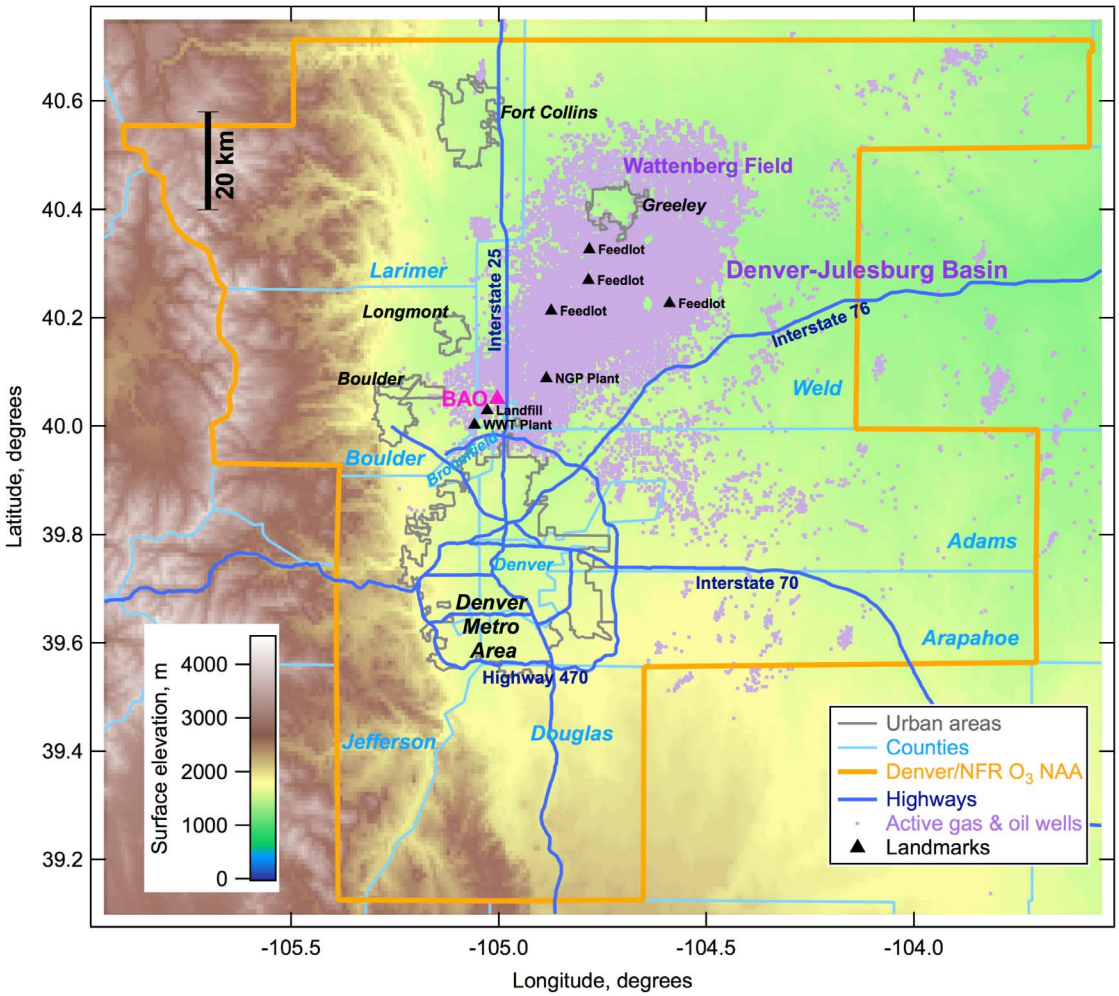

Figure 1. Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, based on COGCC well data). Also shown are the locations of landmarks used in the study, including selected point sources (NGP Plant = natural gas processing plant, WWT Plant = Lafayette wastewater treatment plant).

Figure S1).[1] In 2008, the DJB was home to over 20,000 active natural gas and condensate wells. Over 90% of the production in 2008 came from tight gas formations.

[4] A few recent studies have looked at the impact of oil and gas operations on air composition at the local and regional scales in North America. *Katzenstein et al.* [2003] reported results of two intensive surface air discrete sampling efforts over the Anadarko Fossil Fuel Basin in the southwestern United States in 2002. Their analysis revealed substantial regional atmospheric CH_4 and non-methane hydrocarbon (NMHC) pollution over parts of Texas, Oklahoma, and Kansas, which they attributed to emissions from the oil and gas industry operations. More recently, *Schnell et al.* [2009] observed very high wintertime ozone levels in the vicinity of the Jonah-Pinedale Anticline natural gas field in western Wyoming. *Ryerson et al.* [2003], *Wert et al.* [2003], *de Gouw et al.* [2009] and *Mellqvist et al.* [2010] reported elevated emissions of alkenes from petrochemical plants and refineries in the Houston area and studied their contribution to ozone formation. *Simpson et al.* [2010] present an extensive analysis of atmospheric mixing ratios for a long list of trace gases over oil sands mining operations in Alberta during one flight of the 2008 Arctic Research of the Composition of the Troposphere from Aircraft and Satellites campaign. Our study distinguishes itself from previous ones by the fact that it relies substantially on the analysis of daily air samples collected at a single tall-tower monitoring site between August 2007 and April 2010.

[5] Colorado has a long history of fossil fuel extraction [*Scamehorn*, 2002]. Colorado natural gas production has been increasing since the 1980s, and its share of national production jumped from 3% in 2000 to 5.4% in 2008. 1.3% of the nationally produced oil in 2008 also came from Colorado, primarily from the DJB in northeastern Colorado and from the Piceance Basin in western Colorado. As of

[1]Auxiliary materials are available in the HTML. doi:10.1029/2011JD016360.

2004, Colorado also contained 43 natural gas processing plants, representing 3.5% of the conterminous U.S. processing capacity [*U.S. Energy Information Administration* (*EIA*), 2006], and two oil refineries, located in Commerce City, in Adams County just north of Denver.

[6] Emissions management requirements for both air quality and climate-relevant gases have led the state of Colorado to build detailed baseline emissions inventories for ozone precursors, including volatile organic compounds (VOCs), and for GHGs. Since 2004, a large fraction of the Colorado Northern Front Range, including Weld County and the Denver metropolitan area, has been in violation of the 8-h ozone national ambient air quality standard [*Colorado Department of Public Health and Environment* (*CDPHE*), 2008]. In December 2007, the Denver and Colorado Northern Front Range (DNFR) region was officially designated as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard (see area encompassed by golden boundary in Figure 1). At the end of 2007, Colorado also adopted a Climate Action Plan, which sets greenhouse gas emissions reduction targets for the state [*Ritter*, 2007].

[7] Methane, a strong greenhouse gas with a global warming potential (GWP) of 25 over a 100 yr time horizon [*Intergovernmental Panel on Climate Change*, 2007], accounts for a significant fraction of Colorado GHG emissions, estimated at 14% in 2005 (*Strait et al.* [2007] and auxiliary material Table S1; note that in this report, the oil and gas industry CH_4 emission estimates were calculated with the EPA State Greenhouse Gas Inventory Tool). The natural gas industry (including exploration, production, processing, transmission and distribution) is the single largest source of CH_4 in the state of Colorado (estimated at 238 Gg/yr or ktonnes/yr), followed closely by coal mining (233 Gg/yr); note that all operating surface and underground coal mines are now in western Colorado. Emission estimates for oil production operations in the state were much lower, at 9.5 Gg/yr, than those from gas production. In 2005, Weld County represented 16.5% of the state's natural gas production and 51% of the state crude oil/ natural gas condensate production (auxiliary material Table S2). Scaling the state's total CH_4 emission estimates from *Strait et al.* [2007], rough estimates for the 2005 CH_4 source from natural gas production and processing operations and from natural gas condensate/oil production in Weld County are 19.6 Gg and 4.8 Gg, respectively. It is important to stress here that there are large uncertainties associated with these inventory-derived estimates.

[8] Other important sources of CH_4 in the state include large open-air cattle feedlots, landfills, wastewater treatment facilities, forest fires, and agriculture waste burning, which are all difficult to quantify. 2005 state total CH_4 emissions from enteric fermentation and manure management were estimated at 143 and 48 Gg/yr, respectively [*Strait et al.*, 2007]; this combined source is of comparable magnitude to the estimate from natural gas systems. On-road transportation is not a substantial source of methane [*Nam et al.*, 2004].

[9] In 2006, forty percent of the DNFR NAA's total anthropogenic VOC emissions were estimated to be due to oil and gas operations [*CDPHE*, 2008]. Over the past few years, the State of Colorado has adopted more stringent VOC emission controls for oil and gas exploration and processing activities. In 2007, the Independent Petroleum Association of Mountain States (IPAMS, now Western Energy Alliance), in conjunction with the Western Regional Air Partnership (WRAP), funded a working group to build a state-of-the-knowledge process-based inventory of total VOC and NOx sources involved in oil and gas exploration, production and gathering activities for the western United State's fossil fuel basins, hereafter referred to as the WRAP Phase III effort (http://www.wrapair.org/forums/ogwg/index.html). Most of the oil and gas production in the DJB is concentrated in Weld County. Large and small condensate storage tanks in the County are estimated to be the largest VOC fossil fuel production source category (59% and 9% respectively), followed by pneumatic devices (valve controllers) and unpermitted fugitives emissions (13% and 9% respectively). A detailed breakdown of the WRAP oil and gas source contributions is shown in auxiliary material Figure S2 for 2006 emissions and projected 2010 emissions [*Bar-Ilan et al.*, 2008a, 2008b]. The EPA NEI 2005 for Weld County, used until recently by most air quality modelers, did not include VOC sources from oil and natural gas operations (auxiliary material Table S3).

[10] Benzene (C_6H_6) is a known human carcinogen and it is one of the 188 hazardous air pollutants (HAPs) tracked by the EPA National Air Toxics Assessment (NATA). Benzene, like VOCs and CH_4, can be released at many different stages of oil and gas production and processing. Natural gas itself can contain varying amounts of aromatic hydrocarbons, including C_6H_6 [*U. S. Environmental Protection Agency* (*EPA*), 1998]. Natural gas associated with oil production (such sources are located in several places around the DJB) usually has higher C_6H_6 levels [*Burns*, 1999] than non-associated natural gas. Glycol dehydrators used at wells and processing facilities to remove water from pumped natural gas can vent large amounts of C_6H_6 to the atmosphere when the glycol undergoes regeneration [*EPA*, 1998]. Condensate tanks, venting and flaring at the wellheads, compressors, processing plants, and engine exhaust are also known sources of C_6H_6 [*EPA*, 1998]. C_6H_6 can also be present in the liquids used for fracturing wells [*EPA*, 2004].

[11] In this paper, we focus on describing and interpreting the measured variability in CH_4 and C_{3-5} alkanes observed in the Colorado Northern Front Range. We use data from daily air samples collected at a NOAA tall tower located in Weld County as well as continuous CH_4 observations and discrete targeted samples from an intensive mobile sampling campaign in the Colorado Northern Front Range. These atmospheric measurements are then used together with other emissions data sets to provide an independent view of methane and non-methane hydrocarbon emissions inventory results.

[12] The paper is organized as follows. Section 2 describes the study design and sampling methods. Section 3 presents results from the tall tower and the Mobile Lab surveys, in particular the strong correlation among the various alkanes measured. Based on the multispecies analysis in the discrete air samples, we were able to identify two major sources of C_6H_6 in Weld County. In section 4.1 we discuss the results and in section 4.2 we compare the observed ambient molar ratios with other relevant data sets, including raw natural gas composition data from 77 gas wells in the DJB. The last discussion section 4.3, is an attempt to shed new light on

Table 1. Locations of a Subset of the NOAA ESRL Towers and Aircraft Profile Sites Used in This Study[a]

Site Code	City	State	Latitude (°N)	Longitude (°E)	Elevation (Meters Above Sea Level)	Sampling Height (Meters Above Ground)
BAO	Erie	Colorado	40.05	105.01	1584	300
LEF	Park Falls	Wisconsin	45.93	90.27	472	396
NWF	Niwot Ridge	Colorado	40.03	105.55	3050	23
STR	San Francisco	California	37.755	122.45	254	232
WGC	Walnut Grove	California	38.26	121.49	0	91
WKT	Moody	Texas	31.32	97.33	251	457
SGP[b]	Southern Great Plains	Oklahoma	36.80	97.50	314	<650

[a]STR and WGC in Northern California are collaborations with Department of Energy Environmental Energy Technologies Division at Lawrence Berkeley National Laboratory (PI: Marc Fischer). The last column gives the altitudes of the quasi-daily flask air samples used in this study. We use midday data for all sites, but at Niwot Ridge Forest we used nighttime data to capture background air from summertime downslope flow. We also show the location information of SGP, a NOAA ESRL aircraft site in north central Oklahoma, for which we used samples taken below 650 m altitude.
[b]Aircraft discrete air samples.

methane and VOC emission estimates from oil and gas operations in Weld County. We first describe how we derived speciated bottom-up emission estimates based on the WRAP Phase III total VOC emission inventories for counties in the DJB. We then used (1) an average ambient propane-to-methane molar ratio, (2) a set of bottom-up estimates of propane and methane flashing emissions in Weld County and (3) three different estimates of the propane-to-methane molar ratio for the raw gas leaks to build top-down methane and propane emission scenarios for venting sources in the county. We also scaled the top-down propane (C_3H_8) estimates with the observed ambient alkane ratios to calculate top-down emission estimates for n-butane (n-C_4H_{10}), i- and n-pentane (i-C_5H_{12}, n-C_5H_{12}), and benzene. We summarize our main conclusions in section 5.

2. The Front Range Emissions Study: Sampling Strategy, Instrumentation, and Sample Analysis

2.1. Overall Experimental Design

[13] The Colorado Northern Front Range study was a pilot project to design and test a new measurement strategy to characterize GHG emissions at the regional level. The anchor of the study was a 300-m tall tower located in Weld County, 25 km east-northeast of Boulder and 35 km north of Denver, called the Boulder Atmospheric Observatory (BAO) [40.05°N, 105.01°W; base of tower at 1584 m above sea level] (Figure 1). The BAO is situated on the southwestern edge of the DJB. A large landfill and a wastewater treatment plant are located a few kilometers southwest of BAO. Interstate 25, a major highway going through Denver, runs in a north-south direction 2 km east of the site. Both continuous and discrete air sampling have been conducted at BAO since 2007.

[14] To put the BAO air samples into a larger regional context and to better understand the sources that impacted the discrete air samples, we made automobile-based on-road air sampling surveys around the Colorado Northern Front Range in June and July 2008 with an instrumented "Mobile Lab" and the same discrete sampling apparatus used at all the NOAA towers and aircraft sampling sites.

2.2. BAO and Other NOAA Cooperative Tall Towers

[15] The BAO tall tower has been used as a research facility of boundary layer dynamics since the 1970s [*Kaimal and Gaynor*, 1983]. The BAO tower was instrumented by the NOAA ESRL Global Monitoring Division (GMD) in Boulder in April 2007, with sampling by a quasi-continuous CO_2 non-dispersive infrared sensor and a CO Gas Filter Correlation instrument, both oscillating between three intake levels (22, 100 and 300 m above ground level) (Andrews et al., manuscript in preparation, 2012). Two continuous ozone UV-absorption instruments have also been deployed to monitor ozone at the surface and at the 300-m level.

[16] The tower is equipped to collect discrete air samples from the 300-m level using a programmable compressor package (PCP) and a programmable flasks package (PFP) described later in section 2.4. Since August 2007 one or two air samples have been taken approximately daily in glass flasks using PFPs and a PCP. The air samples are brought back to GMD for analysis on three different systems to measure a series of compounds, including methane (CH_4, also referred to as C_1), CO, propane (C_3H_8, also referred to as C_3), n-butane (n-C_4H_{10}, nC_4), isopentane (i-C_5H_{12}, iC_5), n-pentane (n-C_5H_{12}, nC_5), acetylene (C_2H_2), benzene, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Ethane and i-butane were not measured.

[17] In this study, we use the results from the NOAA GMD multispecies analysis of air samples collected midday at the 300-m level together with 30- second wind speed and direction measured at 300-m. 30-min averages of the wind speed and direction prior to the collection time of each flask are used to separate samples of air masses coming from three different geographic sectors: the North and East (NE sector), where the majority of the DJB oil and gas wells are located; the South (S sector), mostly influenced by the Denver metropolitan area; and the West (W sector), with relatively cleaner air.

[18] In 2008, NOAA and its collaborators were operating a regional air sampling network of eight towers and 18 aircraft profiling sites located across the continental U.S. employing in situ measurements (most towers) and flask sampling protocols (towers and aircraft sites) that were similar to those used at BAO. Median mixing ratios for several alkanes, benzene, acetylene, and carbon monoxide from BAO and a subset of five other NOAA towers and from one aircraft site are presented in the Results (section 3). Table 1 provides the three letter codes used for each sampling site, their locations and sampling heights. STR is located in San Francisco. WGC is located 34 km south of downtown Sacramento in California's Central Valley where

Table 2. List of the Front Range Mobile Lab Measurement and Flasks Sampling Surveys[a]

Road Survey Number	Road Survey Date	Geographical Area/Target Sources	Measurements/Sampling Technique
1	June 4	Boulder	12 flasks
2	June 11	Boulder + Foothills	12 flasks
3	June 19	NOAA-Longmont-Fort Collins- Greeley (Oil and Gas Drilling, Feedlots)	24 flasks
4	July 1	NOAA - Denver	12 flasks
5	July 9	Around Denver	Picarro
6	July 14	NOAA - Greeley	12 flasks
7	July 15	NOAA-Greeley	Picarro
8	July 25	BAO surroundings - Natural Gas Processing Plant - Feedlot	Picarro + 8 flasks
9	July 31	"Regional" CH_4 enhancements, Landfill, Corn field	Picarro + 12 flasks

[a]Some trips (1, 2, 3, 4, 6) sampled air using the flask only. Surveys 5 and 7 used only the continuous analyzers on the Mobile Lab with no discrete flask collection. The last two trips targeted flask sampling close to known point or area sources based on the continuous methane measurement display in the Mobile Lab.

agriculture is the main economic sector. Irrigated crop fields and feedlots contribute to the higher CH_4 observed at WGC. The LEF tower in northern Wisconsin is in the middle of the Chequamegon National Forest which is a mix of temperate/boreal forest and lowlands/wetlands [*Werner et al.*, 2003]. Air samples from NWF (surface elevation 3050 m), in the Colorado Rocky Mountains, mostly reflect relatively unpolluted air from the free troposphere. The 457m tall Texas tower (WKT) is located between Dallas/Fort Worth and Austin. It often samples air masses from the surrounding metropolitan areas. In summer especially, it also detects air masses with cleaner background levels arriving from the Gulf of Mexico. The SGP NOAA aircraft sampling site (Sweeney et al., manuscript in preparation, 2012; http://www.esrl.noaa.gov/gmd/ccgg/aircraft/) in northern Oklahoma is also used in the comparison study. At each aircraft site, twelve discrete air samples are collected at specified altitudes on a weekly or biweekly basis. Oklahoma is the fourth largest state for natural gas production in the USA (EIA, Natural gas navigator, 2008, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm) and one would expect to observe signatures of oil and gas drilling operations at both SGP and BAO. Additional information on the tower and aircraft programs is available at http://www.esrl.noaa.gov/gmd/ccgg/. Median summer mixing ratios for several alkanes, C_2H_2, C_6H_6 and CO are presented in the Results section.

2.3. Mobile Sampling

[19] Two mobile sampling strategies were employed during this study. The first, the Mobile Lab, consisted of a fast response CO_2 and CH_4 analyzer (Picarro, Inc.), a CO gas-filter correlation instrument from Thermo Environmental, Inc., an O_3 UV-absorption analyzer from 2B Technologies and a Global Positioning System (GPS) unit. All were installed onboard a vehicle. A set of 3 parallel inlets attached to a rack on top of the vehicle brought in outside air from a few meters above the ground to the instruments. Another simpler sampling strategy was to drive around and collect flask samples at predetermined locations in the Front Range region. A summary of the on-road surveys is given in Table 2.

[20] The Mobile Lab's Picarro Envirosense $CO_2/CH_4/H_2O$ analyzer (model G1301, unit CFADS09) employs Wavelength-Scanned Cavity Ring-Down Spectroscopy (WS-CRDS), a time-based measurement utilizing a near-infrared laser to measure a spectral signature of the molecule. CO_2, CH_4, and water vapor were measured at a 5-s sampling rate (0.2 Hz), with a standard deviation of 0.09 ppm in CO_2 and 0.7 ppb for CH_4. The sample was not dried prior to analysis, and the CO_2 and CH_4 mole fractions were corrected for water vapor after the experiment based on laboratory tests. For water mole fractions between 1% and 2.5%, the relative magnitude of the CH_4 correction was quasi-linear, with values between 1 and 2.6%. CO_2 and CH_4 mole fractions were assigned against a reference gas tied to the relevant World Meteorological Organization (WMO) calibration scale. Total measurement uncertainties were 0.1 ppm for CO_2 and 2 ppb for CH_4 (Sweeney et al., manuscript in preparation, 2012). The CO and ozone data from the Mobile Lab are not discussed here. GPS data were also collected in the Mobile Lab at 1 Hz, to allow data from the continuous analyzers to be merged with the location of the vehicle.

[21] The excursions with the flask sampler (PFP) focused on characterizing the concentrations of trace gases in Boulder (June 4 and 11, 2008), the northeastern Front Range (June 19), Denver (July 1) and around oil and gas wells and feedlots in Weld County south of Greeley (July 14) (see Table 2). Up to 24 sampling locations away from direct vehicle emissions were chosen before each drive.

[22] Each Mobile Lab drive lasted from four to six hours, after a ~30 min warm-up on the NOAA campus for the continuous analyzer before switching to battery mode. The first two Mobile Lab drives, which did not include discrete air sampling, were surveys around Denver (July 9) and between Boulder and Greeley (July 15). The last two drives with the Mobile Lab (July 25 and 31) combined in situ measurements with discrete flask sampling to target emissions from specific sources: the quasi-real-time display of the data from the continuous CO_2/CH_4 analyzer was used to collect targeted flask samples at strong CH_4 point sources in the vicinity of BAO. Discrete air samples were always collected upwind of the surveying vehicle and when possible away from major road traffic.

2.4. Chemical Analyses of Flask Samples

[23] Discrete air samples were collected at BAO and during the road surveys with a two-component collection apparatus. One (PCP) includes pumps and batteries, along with an onboard microprocessor to control air sampling. Air was drawn through Teflon tubing attached to an expandable 3-m long fishing pole. The second package (PFP) contained a sampling manifold and twelve cylindrical, 0.7 L, glass flasks of flow-through design, fitted with Teflon O-ring on both

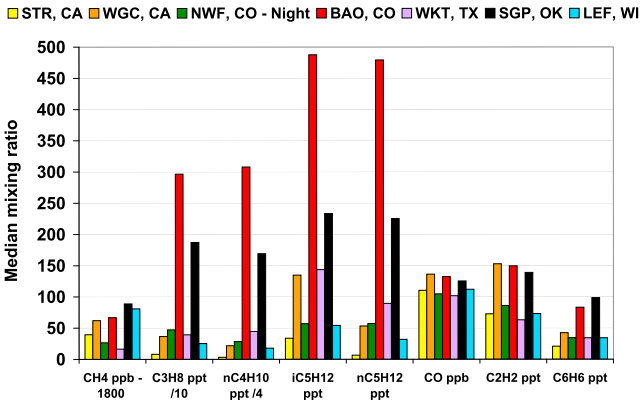

Figure 2. Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June–August (2007–2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly downslope winds. Notice the different units with all columns and the different scaling applied to methane, propane and n-butane.

stopcocks. Before deployment, manifold and flasks were leak-checked then flushed and pressurized to ~1.4 atm with synthetic dry zero-air containing approximately 330 ppm of CO_2 and no detectable CH_4. During sampling, the manifold and flasks were flushed sequentially, at ~5 L min^{-1} for about 1 min and 10 L min^{-1} for about 3 min respectively, before the flasks were pressurized to 2.7 atm. Upon returning to the NOAA lab, the PFP manifold was leak-checked and metadata recorded by the PFP during the flushing and sampling procedures were read to verify the integrity of each air sample collected. In case of detected inadequate flushing or filling, the affected air sample is not analyzed.

[24] Samples collected in flasks were analyzed for close to 60 compounds by NOAA GMD (http://www.esrl.noaa.gov/gmd/ccgg/aircraft/analysis.html). In this paper, we focus on eight species: 5 alkanes (CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) as well as CO, C_2H_2 and C_6H_6. CH_4 and CO in each flask were first quantified on one of two nearly identical automated analytical systems (MAGICC 1 and 2). These systems consist of a custom-made gas inlet system, gas-specific analyzers, and system-control software. Our gas inlet systems use a series of stream selection valves to select an air sample or standard gas, pass it through a trap for drying maintained at ~−80°C, and then to an analyzer.

[25] CH_4 was measured by gas chromatography (GC) with flame ionization detection (±1.2 ppb = average repeatability determined as 1 s.d. of ~20 aliquots of natural air measured from a cylinder) [*Dlugokencky et al.*, 1994]. We use the following abbreviations for measured mole fractions: ppm = μmol mol^{-1}, ppb = nmol mol^{-1}, and ppt = pmol mol^{-1}. CO was measured directly by resonance fluorescence at ~150 nm (±0.2 ppb) [*Gerbig et al.*, 1999; *Novelli et al.*, 1998]. All measurements are reported as dry air mole fractions relative to internally consistent calibration scales maintained at NOAA (http://www.esrl.noaa.gov/gmd/ccl/scales.html).

[26] Gas chromatography/mass spectrometric (GC/MS) measurements were also performed on ~200 mL aliquots taken from the flask samples and pre-concentrated with a cryogenic trap at near liquid nitrogen temperatures [*Montzka et al.*, 1993]. Analytes desorbed at ~110°C were then separated by a temperature-programmed GC column (combination 25 m × 0.25 mm DB5 and 30 m × 0.25 mm Gaspro), followed by detection with mass spectrometry by monitoring compound-specific ion mass-to-charge ratios. Flask sample responses were calibrated versus whole air working reference gases which, in turn, are calibrated with respect to gravimetric primary standards (NOAA scales: benzene on NOAA-2006 and all other hydrocarbons (besides CH_4) on NOAA-2008). We used a provisional calibration for n-butane based on a diluted Scott Specialty Gas standard. Total uncertainties for analyses from the GC/MS reported here are <5% (accuracy) for all species except n-C_4H_{10} and C_2H_2, for which the total uncertainty at the time of this study was of the order of 15–20%. Measurement precision as repeatability is generally less than 2% for compounds present at mixing ratios above 10 ppt.

[27] To access the storage stability of the compounds of interest in the PFPs, we conducted storage tests of typically 30 days duration, which is greater than the actual storage time of the samples used in this study. Results for C_2H_2 and C_3H_8 show no statistically significant enhancement or degradation with respect to our "control" (the original test gas tank results) within our analytical uncertainty. For the remaining species, enhancements or losses average less than 3% for the 30 day tests. More information on the quality control of the flask analysis data is available at http://www.esrl.noaa.gov/gmd/ccgg/aircraft/qc.html.

[28] The flask samples were first sent to the GC/MS instrument for hydrocarbons, CFCs, and HFCs before being analyzed for major GHGs. This first step was meant to screen highly polluted samples that could potentially damage the greenhouse gas MAGICC analysis line with concentrations well above "background" levels. The time interval between flask collection and flask analysis spanned between 1 to 11 days for the GC/MS analysis and 3 to 12 days for MAGICC analysis.

3. Results

3.1. BAO Tall Tower: Long-Term Sampling Platform for Regional Emissions

3.1.1. Comparing BAO With Other Sampling Sites in the U.S.

[29] Air samples collected at BAO have a distinct chemical signature (Figure 2), showing enhanced levels of most alkanes (C_3H_8, n-C_4H_{10}, i-C_5H_{12} and n-C_5H_{12}) in comparison to results from other NOAA cooperative tall towers (see summary of site locations in Table 1 and data time series in auxiliary material Figure S1). The midday summer time median mixing ratios for C_3H_8 and n-C_4H_{10} at BAO were at least 6 times higher than those observed at most other tall tower sites. For i-C_5H_{12} and n-C_5H_{12}, the summertime median mixing ratios at BAO were at least 3 times higher than at the other tall towers.

[30] In Figure 2, we show nighttime measurements at the Niwot Ridge Forest tower (NWF) located at a high elevation site on the eastern slopes of the Rocky Mountains, 50 km west of BAO. During the summer nighttime, downslope flow brings clean air to the tower [*Roberts et al.*, 1984]. The median summer mixing ratios at NWF for all the species shown in Figure 2 are much lower than at BAO, as would be expected given the site's remote location.

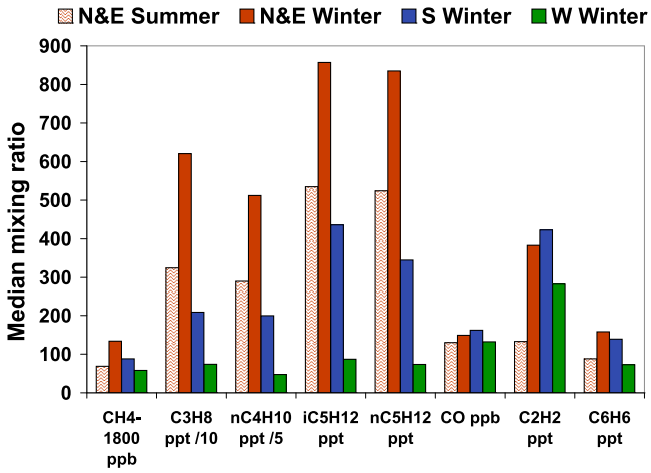

Figure 3. Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-m level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean air. The time span of the data is from August 2007 to April 2010. Summer includes data from June to August and winter includes data from November to April. Due to the small number of data points (<15), we do not show summer values for the S and W wind sectors. Data outside of the 11am-3pm local time window were not used. Notice the different scales used for methane, propane and n-butane. The minimum number of data points used for each wind sector is: NE summer 33, NE winter 89, S winter 65 and W winter 111.

[31] Similarly to BAO, the northern Oklahoma aircraft site, SGP, exhibits high alkane levels in the boundary layer and the highest methane summer median mixing ratio of all sites shown in Figure 2 (1889 ppb at SGP versus 1867 ppb at BAO). As for BAO, SGP is located in an oil- and gas-producing region. Oklahoma, the fourth largest state in terms of natural gas production in the U.S., has a much denser network of interstate and intrastate natural gas pipelines compared to Colorado. *Katzenstein et al.* [2003] documented the spatial extent of alkane plumes around the gas fields of the Anadarko Basin in Texas, Oklahoma, and Kansas during two sampling intensives. The authors estimated that methane emissions from the oil and gas industry in that entire region could be as high as 4–6 Tg CH_4/yr, which is 13–20% of the U.S. total methane emission estimate for year 2005 reported in the latest EPA U.S. GHG Inventory (EPA, Inventory of U.S. Greenhouse Gas emissions and Sinks: 1990–2009, 2011, available at http://www.epa.gov/climatechange/emissions).

[32] Enhancements of CH_4 at BAO are not as striking in comparison to other sites. CH_4 is a long-lived gas destroyed predominantly by its reaction with OH radicals. CH_4 has a background level that varies depending on the location and season [*Dlugokencky et al.*, 1994], making it more difficult to interpret differences in median summer CH_4 mixing ratios at the suite of towers. Since we do not have continuous measurements of CH_4 at any of the towers except WGC, we cannot clearly separate CH_4 enhancements from background variability in samples with levels between 1800 and 1900 ppb if we only look at CH_4 mixing ratios by themselves (see more on this in the next section).

3.1.2. Influence of Different Sources at BAO

3.1.2.1. Median Mixing Ratios in the Three Wind Sectors

[33] To better separate the various sources influencing air sampled at BAO, Figure 3 shows the observed median mixing ratios of several species as a function of prevailing wind direction. For this calculation, we only used samples for which the associated 30-min average wind speed (prior to collection time) was larger than 2.5 m/s. We separated the data into three wind sectors: NE, including winds from the north, northeast and east (wind directions between 345° and 120°); S, including south winds (120° to 240°); and W, including winds from the west (240° to 345°).

[34] For the NE sector, we can further separate summer (June to August) and winter (November to April) data. For the other two wind sectors, only the winter months have enough data points. The species shown in Figure 3 have different photochemical lifetimes [*Parrish et al.*, 1998], and all are shorter-lived in the summer season. This fact, combined with enhanced vertical mixing in the summer, leads to lower mixing ratios in summer than in winter.

[35] Air masses from the NE sector pass over the oil and gas wells in the DJB and exhibit large alkane enhancements. In winter, median mole fractions of C_3-C_5 alkanes are 8 to 11 times higher in air samples from the NE compared to the samples from the W sector, while the median CH_4 value is 76 ppb higher. The NE wind sector also shows the highest median values of C_6H_6, but not CO and C_2H_2.

[36] C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers in air samples from the NE wind sector are much higher than in air samples coming from the Denver metropolitan area in the South wind sector. Besides being influenced by Denver, southern air masses may pass over two operating landfills, the Commerce City oil refineries, and some oil and gas wells (Figure 1). The S sector BAO CO and C_2H_2 mixing ratios are higher than for the other wind sectors, consistent with the higher density of vehicular emission sources [*Harley et al.*, 1992; *Warneke et al.*, 2007; *Baker et al.*, 2008] south of BAO. There are also occasional spikes in CFC-11 and CFC-12 mixing ratios in the S sector (not shown). These are most probably due to leaks from CFC-containing items in the landfills. Air parcels at BAO coming from the east pass over Interstate Highway 25, which could explain some of the high mole fractions observed for vehicle combustion tracers such as CO, C_2H_2, and C_6H_6 in the NE sector data (see more discussion on C_6H_6 and CO in section 4.4 and Figure 4).

[37] The W wind sector has the lowest median mole fractions for all anthropogenic tracers, consistent with a lower density of emission sources west of BAO compared to the other wind sectors. However, the S and W wind sectors do have some data points with high alkane values, and these data will be discussed further below.

3.1.2.2. Strong Alkane Source Signature

[38] To detect if the air sampled at BAO has specific chemical signatures from various sources, we looked at correlation plots for the species shown in Figure 3. Table 3 summarizes the statistics for various tracer correlations for the three different wind sectors. Figure 4 (left) shows correlation plots of some of these BAO species for summer data in the NE wind sector.

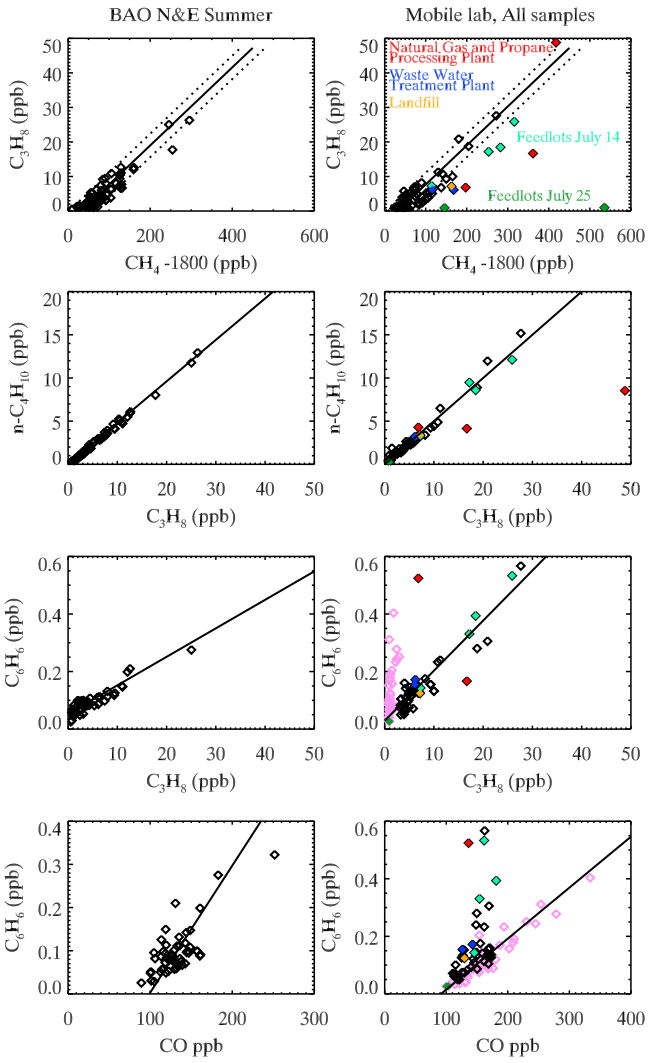

Figure 4. Correlation plots for various species measured in the (left) BAO summertime NE wind sector flask samples and (right) summer 2008 Mobile Lab samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 2009. See also Table 3.

[39] Even though BAO data from the NE winds show the largest alkane mixing ratios (Figure 3), all three sectors exhibit strong correlations between C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers (Table 3). The r^2 values for the correlations between C_3H_8 and n-C_4H_{10} or the C_5H_{12} isomers are over 0.9 for the NE and W sectors. CH_4 is also well correlated with C_3H_8 in the NE wind sector for both seasons. For the NE wind sector BAO summertime data, a min/max range for the C_3H_8/CH_4 slope is 0.099 to 0.109 ppb/ppb.

[40] The tight correlations between the alkanes suggest a common source located in the vicinity of BAO. Since large alkane enhancements are more frequent in the NE wind sector, this common source probably has larger emissions north and east of the tower. This NE wind sector encompasses Interstate Highway 25 and most of the DJB oil and gas wells. The C_3-C_5 alkane mole fractions do not always correlate well with combustion tracers such as C_2H_2 and CO for the BAO NE wind sector (C_{3-5}/CO and C_{3-5}/C_2H_2: $r^2 < 0.3$ for 50 summer samples; C_{3-5}/CO: $r^2 < 0.4$ and C_{3-5}/C_2H_2: $r^2 \sim 0.6$ for 115 winter samples). These results indicate that the source responsible for the elevated alkanes at BAO is not the major source of CO or C_2H_2, which argues against vehicle combustion exhaust as being responsible. Northeastern Colorado is mostly rural with no big cities. The only operating oil refineries in Colorado are in the northern part of the Denver metropolitan area, south of BAO. The main industrial operations in the northeastern Front Range are oil and natural gas exploration and production and natural gas processing and transmission. We therefore hypothesize here that the oil and gas operations in the DJB, as noted earlier in section 2, are a potentially substantial source of alkanes in the region.

3.1.2.3. At Least Two Sources of Benzene in BAO Vicinity

[41] The median winter C_6H_6 mixing ratio at BAO is higher for the NE wind sector compared to the South wind sector, which comprises the Denver metropolitan area. The C_6H_6-to-CO winter correlation is highest for the S and W wind sectors BAO samples ($r^2 = 0.85$ and 0.83 respectively) compared to the NE wind sector data ($r^2 = 0.69$). The C_6H_6-to-CO correlation slope is substantially higher for the NE wind sector data compared to the other two wind sectors, suggesting that there may be a source of benzene in the NE

Table 3. Correlation Slopes and r^2 for Various Species Measured in the BAO Tower Midday Air Flask Samples for Summer (June to August, When More Than 25 Samples Exist) and Winter (November to April) Over the Time Period Spanning August 2007 to April 2010[a]

Sector		BAO North and East						BAO South Winter			BAO West Winter			Mobile Lab Summer		
Season		Summer			Winter											
Molar Ratios y/x	Units	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n	Slope	r^2	n
C_3H_8/ CH_4	ppb/ ppb	**0.104 ± 0.005**	0.85	81	**0.105 ± 0.004**	0.90	115	0.079 ±0.008	0.53	130	**0.085 ± 0.005**	0.73	148	**0.095 ± 0.007**	0.76	77
nC_4H_{10}/ C_3H_8	ppb/ ppb	**0.447 ± 0.013**	1.00	81	**0.435 ± 0.005**	1.0	120	**0.449 ± 0.011**	0.98	131	**0.434 ± 0.006**	1.00	151	**0.490 ± 0.011**	1.00	85
iC_5H_{12}/ C_3H_8	ppb/ ppb	**0.14 1 ± 0.004**	1.00	81	**0.134 ± 0.004**	0.98	120	**0.142 ± 0.009**	0.81	121	**0.130 ± 0.004**	0.94	151	**0.185 ± 0.011**	0.81	85
nC_5H_{12}/ C_3H_8	ppb/ ppb	**0.150 ± 0.003**	1.00	81	**0.136 ± 0.004**	0.98	120	**0.142 ± 0.006**	0.90	131	**0.133 ± 0.003**	0.91	151	**0.186 ± 0.008**	0.92	85
C_6H_6/ C_3H_8	ppt/ ppb	10.1 ± 1.2	0.67	49	**8.2 ± 0.5**	0.79	117	-	0.33	130	-	0.39	150	**17.9 ± 1.1**	0.95	46
C_6H_6/ CO	ppt/ ppb	2.89 ± 0.40	0.58	53	3.18 ± 0.24	0.69	112	**1.57 ± 0.08**	0.85	123	**1.81 ± 0.08**	0.83	148	**1.82 ± 0.12**	0.89	39
C_2H_2/ CO	ppt/ ppb	**3.15 ± 0.33**	0.85	81	**7.51 ± 0.39**	0.85	100	**5.03 ± 0.17**	0.92	110	**5.85 ± 0.25**	0.86	131	**4.32 ± 0.28**	0.89	39
C_6H_6/ C_2H_2	ppt/ ppt	0.51 ± 0.09	0.55	50	**0.34 ± 0.02**	0.90	103	**0.27 ± 0.02**	0.90	111	**0.32 ± 0.02**	0.96	132	**0.37 ± 0.04**	0.75	39

[a]The three wind sectors used in Figure 3 are also used here with a 30-min average wind speed threshold of 2.5 m/s. Also shown are the slopes derived from flask samples collected by the Mobile Lab in summer 2008. The slope is in bold when r^2 is higher than 0.7 and the slope is not shown when r^2 is less than 0.4. The number of data points (n) used for the slope and r^2 calculations are provided. All slope units are ppb/ppb, except for C_6H_6/C_3H_8, C_6H_6/CO and C_2H_2/CO, which are in ppt/ppb. We used the IDL routine linmix_err.pro for the calculations with the following random measurement errors: 2ppb for CH_4 and CO and 5% for C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}, C_2H_2, and C_6H_6.

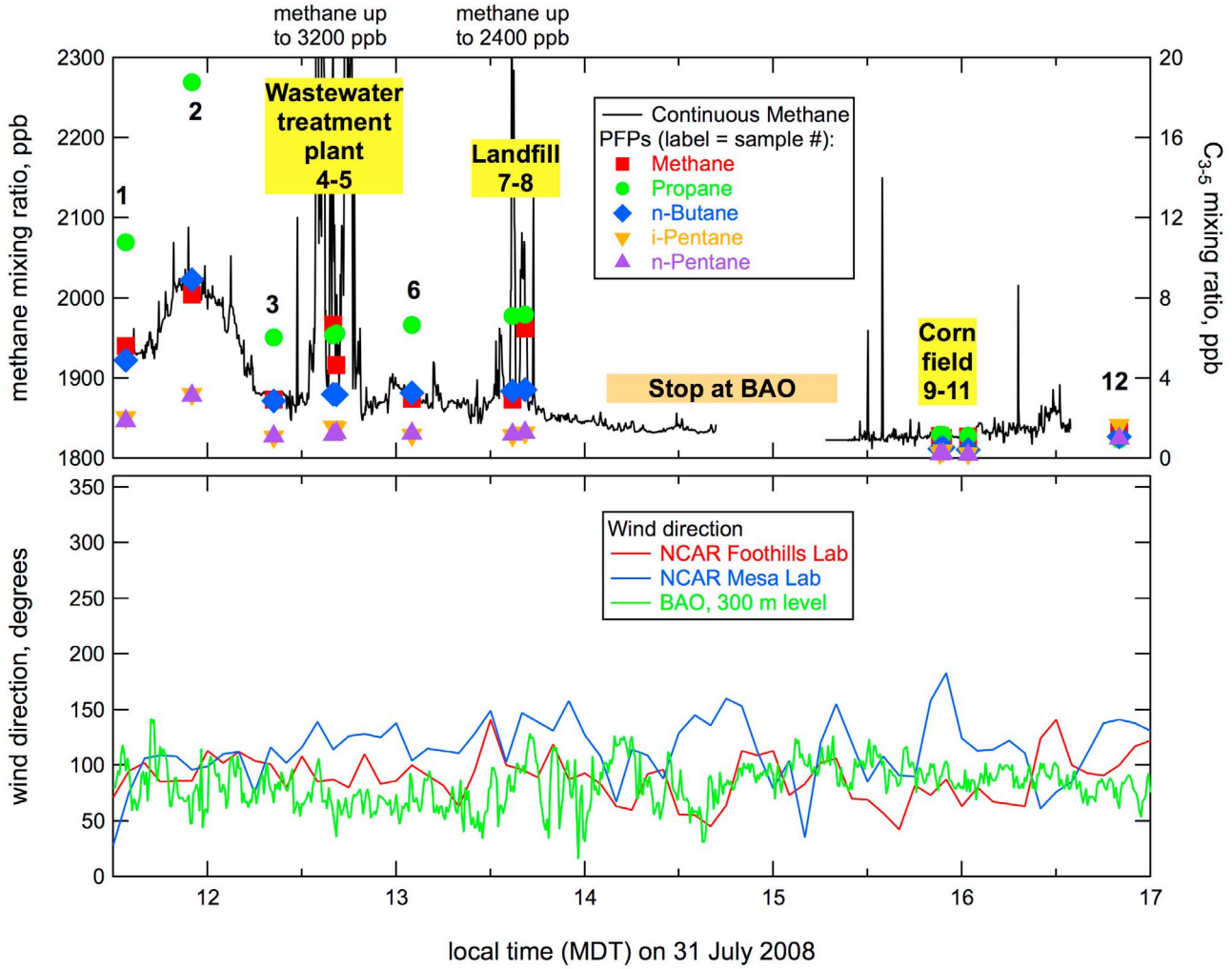

Figure 5. (top) Time series of the continuous methane measurements from Mobile Lab Survey 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in more noisy data for the alkanes and the CFCs ($\sigma < 10\%$ instead of 5%). However, the amplitudes of the C_{3-5} alkane signals are much larger than the noise here. The methane mixing ratio scale is shown on the left hand vertical axis. For all other alkanes, refer to the right hand vertical axis. (bottom) Time series of wind directions at the NCAR Foothills and Mesa Laboratories in Boulder (see Figure 6 for locations) and from the 300-m level at the BAO on July 31, 2008.

that is not a significant source of CO. The C_6H_6-to-C_2H_2 correlation slope is slightly higher for the NE wind sector data compared to the other two wind sectors. C_6H_6 in the BAO data from the NE wind sector correlates more strongly with C_3H_8 than with CO. The C_6H_6-to-C_3H_8 summer correlation slope for the NE wind sector is 10.1 $\pm$ 1.2 ppt/ppb ($r^2 = 0.67$).

[42] For the S and W wind sectors BAO data, the C_6H_6-to-C_2H_2 (0.27 - 0.32 ppt/ppt) and C_6H_6-to-CO (1.57 - 1.81 ppt/ppb) slopes are larger than observed emissions ratios for the Boston/New York City area in 2004: 0.171 ppt/ppt for C_6H_6-to-C_2H_2 ratio and 0.617 ppt/ppb for C_6H_6-to-CO ratio [*Warneke et al.*, 2007]. *Baker et al.* [2008] report an atmospheric molar C_6H_6-to-CO ratio of 0.9 ppt/ppb for Denver in summer 2004, which is in between the Boston/NYC emissions ratio value reported by *Warneke et al.* [2007] and the BAO S and W wind sectors correlation slopes.

[43] The analysis of the BAO C_6H_6 data suggests the existence of at least two distinct C_6H_6 sources in the vicinity of BAO: an urban source related mainly to mobile emissions, and a common source of alkanes and C_6H_6 concentrated in northeastern Colorado. We discuss C_6H_6 correlations and sources in more detail in section 4.4.

3.2. On-Road Surveys: Tracking Point and Area Source Chemical Signatures

[44] Road surveys with flask sampling and the Mobile Lab with the fast-response CH_4 analyzer were carried out in June–July 2008 (Table 2). The extensive chemical analysis of air samples collected in the Front Range provides a snapshot of a broader chemical composition of the regional boundary layer during the time of the study. The Mobile Lab surveys around the Front Range using the in situ CH_4 analyzer allowed us to detect large-scale plumes with long-

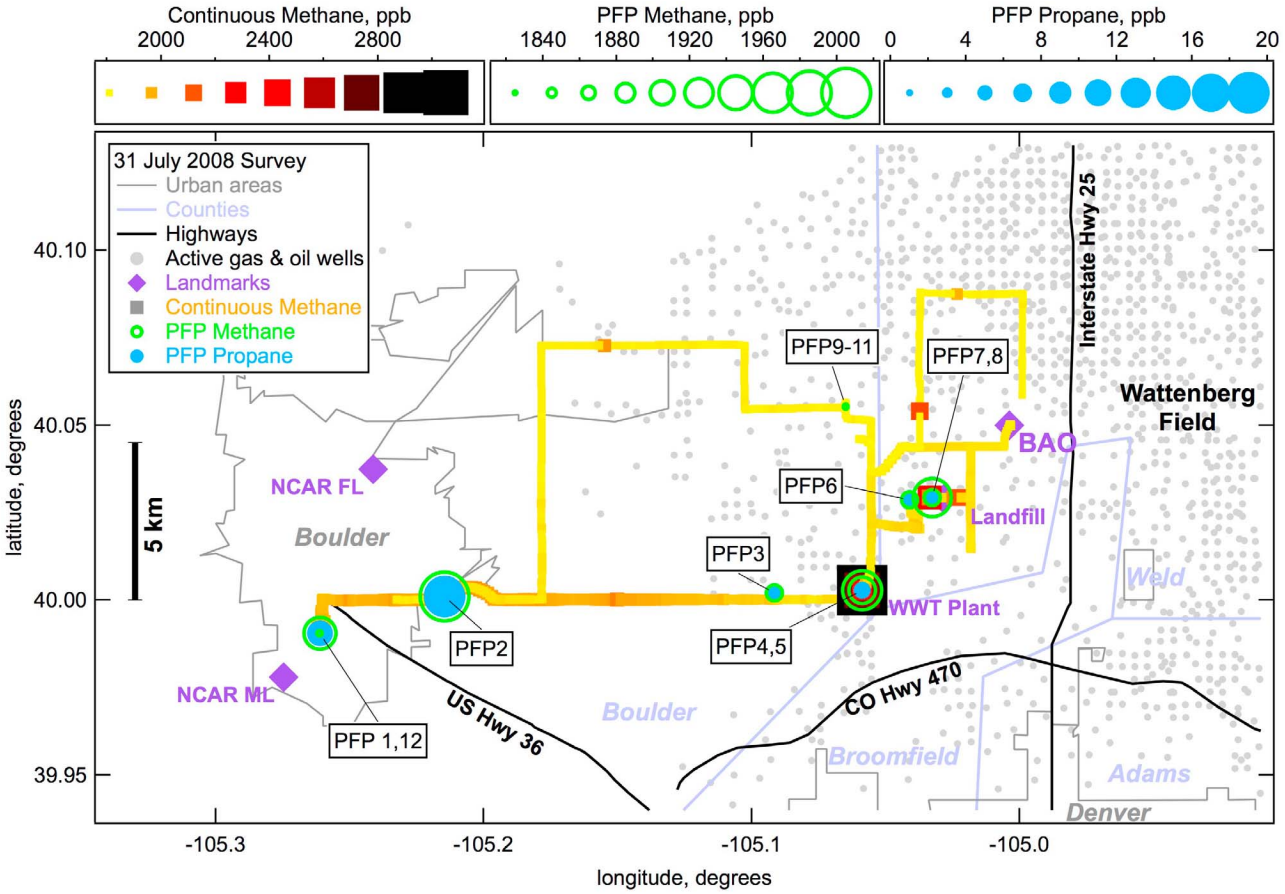

Figure 6. Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey 9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (squares, green circles) and flask propane (blue circles). The labels indicate the flask sample number (also shown in the time series in Figure 5). NCAR = National Center for Atmospheric Research, FL = NCAR Foothills Laboratory, ML = NCAR Mesa Laboratory, WWT Plant = Lafayette wastewater treatment plant.

lasting enhancements of CH_4 mixing ratios as well as small-scale plumes associated with local CH_4 point sources. In the last two Mobile Lab surveys (surveys 8 and 9), we combined the monitoring of the continuous CH_4 analyzer with targeted flask sampling, using the CH_4 data to decide when to collect flask samples in and out of plumes.

[45] The regional background CH_4 mixing ratio at the surface (interpreted here as the lowest methane level sustained for ~10 min or more) was between 1800 ppb and 1840 ppb for most surveys. Some of the highest "instantaneous" CH_4 mixing ratios measured during the Mobile Lab surveys were: 3166 ppb at a wastewater treatment plant, 2329 ppb at a landfill, 2825 ppb at a feedlot near Dacono, over 7000 ppb close to a feedlot waste pond near Greeley, and 4709 ppb at a large natural gas processing and propane plant in Fort Lupton (Figure 1).

[46] The analysis of the summer 2008 intensive data suggests that regional scale mixing ratio enhancements of CH_4 and other alkanes are not rare events in the Colorado Northern Front Range airshed. Their occurrence and extent depends on both emissions and surface wind conditions, which are quite variable and difficult to predict in this area. During the Mobile Lab road surveys, the high-frequency measurements of CO_2 and CH_4 did not exhibit any correlation. Unlike CO_2, the CH_4 enhancements were not related to on-road emissions. Below we present two examples of regional enhancements of CH_4 observed during the Front Range Mobile Lab surveys.

3.2.1. Survey 9: C_{3-5} Alkane Levels Follow Large-Scale Changes in Methane

[47] Figure 5 shows a time series of the continuous CH_4 mixing ratio data and alkane mixing ratios measured in twelve flask samples collected during the Front Range Mobile Lab survey on 31 July 2008 (flasks 1 to 12, sampled sequentially as shown in Figure 6). The wind direction on that day was from the ENE or E at the NCAR Foothills Lab and BAO tower. The Mobile Lab left the NOAA campus in Boulder around 11:40 A.M. and measured increasing CH_4 levels going east toward the BAO tower (Figure 6). An air sample was collected close to the peak of the CH_4 broad enhancement centered around 11:55 A.M. The CH_4 mixing ratio then decreased over the next 25 min and reached a local minimum close to 1875 ppb. The CH_4 level stayed around 1875 ppb for over one hour and then decreased again, more slowly this time, to ~1830 ppb over the next two hours.

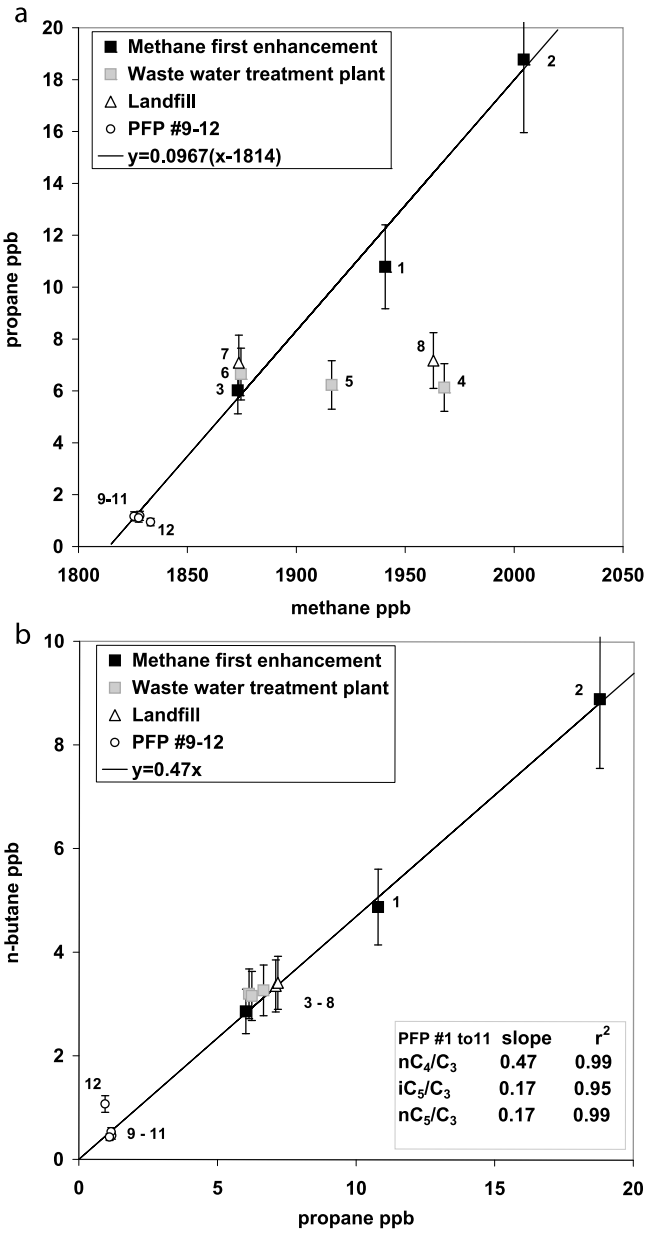

Figure 7. (a) Propane versus methane mixing ratios for air samples collected during Survey 9 on July 31, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 7a shows the correlation line for samples not impacted by local sources of methane (all flasks except 4, 5, 8, and 12). The black line in Figure 7b shows the correlation line for all samples except flask 12. The flask sample number is shown next to each data point. The twelve samples were filled sequentially (see Figure 6).

[48] Flasks 1 to 3 were collected before, at the peak, and immediately after the broad CH_4 feature between 11:40 and 12:15. Flasks 4 and 5 were sampled close to a wastewater treatment plant and flasks 7 to 8 were sampled in a landfill. The in situ measurements showed that CH_4 was still elevated above background as these samples were collected. After a 90-min stop at BAO to recharge the Mobile Lab UPS batteries, flasks 9 to 11 were collected in a corn field while the in situ measurements showed lower CH_4 levels. The last flask sample was collected on the NOAA campus just before 17:00 MDT, about 5.5 h after the first flask sample was collected. The flask samples were always collected upwind of the Mobile Lab car exhaust.

[49] Sharp spikes in the continuous CH_4 data reflect local point sources (wastewater treatment plant, landfill). The highly variable signals in both the continuous and discrete CH_4 close to these sources are driven by the spatial heterogeneity of the CH_4 emissions and variations in wind speed and direction. Broader enhancements in the continuous CH_4 data reflect larger (regional) plumes. The last flask (12) sampled at NOAA has much higher levels of combustion tracers (CO, C_2H_2, C_6H_6) than the other samples.

[50] Figure 7 shows correlation plots for C_3H_8 versus CH_4 and n-C_4H_{10} versus C_3H_8 in the 12 flasks taken on 31 July. Air samples not directly influenced by identified point sources (flasks 1–3, 6–7, 9–12) show a very strong correlation between the various measured alkanes. Using the data from the air samples not directly influenced by identified point sources (flasks 1–3, 6–7, 9–12), we derive a C_3H_8-to-CH_4 (C_3/C_1) mixing ratio slope of 0.097 $\pm$ 0.005 ppb/ppb (Figure 7a). This slope is very similar to the one observed for the summertime NE wind sector data at BAO (0.104 $\pm$ 0.005; Table 3). Three air samples collected downwind of the wastewater treatment plant and the landfill (flasks 4–5 and 8) are off the C_3H_8-to-CH_4 correlation line and have higher CH_4 than air samples collected nearby but not under the influence of these local CH_4 sources (flasks 3 and 6). Flask 8 also has elevated CFC-11 (310 ppt) compared to the other samples collected that day (<255 ppt), probably related to leaks from old appliances buried in the landfill.

[51] The C_3-C_5 alkane mixing ratios in samples collected on 31 July are tightly correlated for flasks 1 to 11 with $r^2 > 0.95$ (Figure 7b). As concluded for the BAO alkane mixing ratio enhancements earlier, this tight correlation suggests that the non-methane alkanes measured during the surveys are coming from the same source types. The nC_4/C_3 correlation slope on 31 July (0.47 ppb/ppb; flasks 1–11) is similar to the summer slope in the BAO NE samples (0.45 ppb/ppb), while the 31 July iC_5/C_3 and nC_5/C_3 slopes are slightly higher (0.17 and 0.17 ppb/ppb, respectively) than for BAO (0.14 and 0.15 ppb/ppb, respectively).

3.2.2. Survey 6: Alkane Enhancements in the Denver-Julesburg Oil and Gas Production Zone and Cattle Feedlot Contributions to Methane

[52] The flask-sampling-only mobile survey on 14 July 2008 focused on the agricultural and oil and gas drilling region south of Greeley. Eleven of the twelve air samples collected on 14 July were taken over the Denver-Julesburg Basin (flasks 2–12 in auxiliary material Figure S3). Figure 8a shows a correlation plot of C_3H_8 versus CH_4 mixing ratios in these air samples. Flasks collected NE of BAO and not near feedlots (flasks 4, 6–8, and 10–12) fall on a line: $y = 0.114(x-1830)$ ($r^2 = 0.99$). This slope and the correlation slope calculated for the BAO NE wind sector data are indistinguishable (within the 1-σ uncertainties in the slopes). Four samples collected in the vicinity of four different cattle feedlots (flasks 2, 3, 5, and 9) exhibit a lower C_3H_8-to-CH_4 correlation slope (0.083 ppb/ppb, $r^2 = 0.93$). The r^2 for the C_3H_8-to-CH_4 correlation using all the flasks is 0.91.

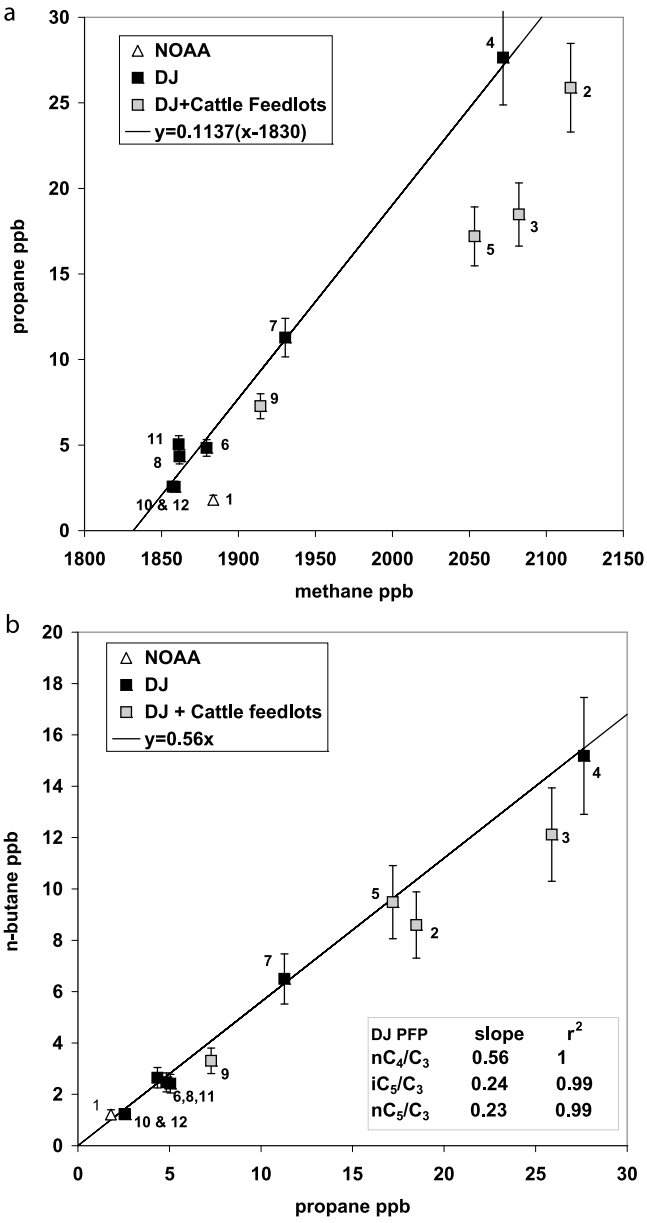

Figure 8. (a) Propane versus methane mixing ratios for air samples collected during Survey 6 on July 14, 2008. (b) The n-butane versus propane mixing ratios in the same air samples. The black line in Figure 8a shows the correlation line for samples not impacted by local sources of methane (all flasks except 1–3, 5, and 9). The black line in Figure 8b shows the correlation line for samples not impacted by local sources of propane.

[53] The n-C_4H_{10} versus C_3H_8 correlation plot and its slope, along with the n-C_4H_{10}–to-C_3H_8 and C_5H_{12}–to-C_3H_8 correlation slopes for air samples not collected downwind of feedlots are shown in Figure 8b. The r^2 for the n-C_4H_{10}-to-C_3H_8 correlation using all the flasks is 0.98, which is slightly higher than the r^2 for the C_3H_8-to-CH_4 correlation using all flasks (0.91). The r^2 for the i-C_5H_{12}-to-n-C_4H_{10} and n-C_5H_{12}-to-n-C_4H_{10} correlations using all the flasks are 0.96 ppb/ppb and 0.99 ppb/ppb, respectively. These results suggest that cattle feedlots have no substantial impact on n-C_4H_{10} and the C_5H_{12} levels.

[54] The strong correlation observed between the various alkane mixing ratios for air samples not collected downwind of feedlots once again suggests that a common source contributes to most of the observed alkanes enhancements. It is possible that some of the C_3H_8 enhancements seen near the feedlots are due to leaks of propane fuel used for farm operations (R. Klusman, personal communication, 2010). Two flask samples were collected downwind of a cattle feedlot near Dacono during Mobile Lab survey 8, on 25 July 2008. The analysis of these samples revealed large CH_4 enhancements (1946 and 2335 ppb), but no enhancement in C_3H_8 (∼1ppb), n-C_4H_{10} (<300ppt), the C_5H_{12} (<130ppt) or C_6H_6 (<30ppt).

[55] For survey 6, the n-C_4H_{10}-to-C_3H_8 correlation slope (0.56 ppb/ppb) is 16% higher than the summer slope observed at BAO for the NE wind sector data, while the 14 July i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes (0.24 and 0.23 ppb/ppb, respectively) are 76% and 53% higher, respectively, than the summer NE BAO data. These slopes are higher than for flasks from survey 9. The difference in the C_5/C_3 slopes between the various Mobile Lab surveys data and the BAO NE summer data may reflect the spatial variability in the alkane source molar composition.

3.2.3. Benzene Source Signatures

[56] To look at the C_6H_6 correlations with other tracers, the 88 Mobile Lab flask samples have been divided into two subsets, none of which includes the three samples collected downwind of the natural gas and propane processing plant near Dacono, CO. In the summer, the lifetimes of C_6H_6 and C_3H_8 at 800 mbar and 40°N are close to 3 or 4 days and the lifetime of CO is about 10 days [*Finlayson-Pitts and Pitts*, 2000; *Spivakovsky et al.*, 2000].

[57] The first subset of 39 samples has C_3H_8 mixing ratios smaller than 3 ppb and it includes flasks collected mostly during surveys 2, 3 and 4. For this subset influenced mostly by urban and mobile emissions, C_6H_6 correlates well with CO (slope = 1.82 ppt/ppb, r^2 = 0.89) and C_2H_2 (slope = 0.37 ppt/ppt, r^2 = 0.75) but not with C_3H_8 (r^2 < 0.3). The C_6H_6-to-CO correlation slope for this subset is similar to the correlation slopes for the BAO S and W wind sector winter samples.

[58] The second subset of 46 samples corresponds to flasks with a C_3H_8 mixing ratio larger than 3ppb. These flasks were collected mostly during surveys 1, 6, 8 and 9. For this second subset influenced mostly by emissions from the DJB, C_6H_6 correlates well with C_3H_8 (slope = 17.9 ppt/ppb, r^2 = 0.95) but not with CO or C_2H_2 (r^2 < 0.3). The C_6H_6-to-C_3H_8 slope for these samples is almost twice as big as the slope calculated for the BAO NE wind sector data (10.1 ppt/ppb) (Table 3).

4. Discussion

4.1. Comparing the Alkane Enhancements in the BAO and Mobile Lab Data Sets

[59] In the previous section we showed two examples of enhanced alkanes in northeast Colorado using mobile sampling (surveys 6 and 9 on 14 and 31 July 2008, respectively). With lifetimes against OH removal on the order of 3.5, 1.7 and 1.0 days in the summer at 40°N [*Finlayson-Pitts and Pitts*, 2000; *Spivakovsky et al.*, 2000] respectively, C_3H_8,

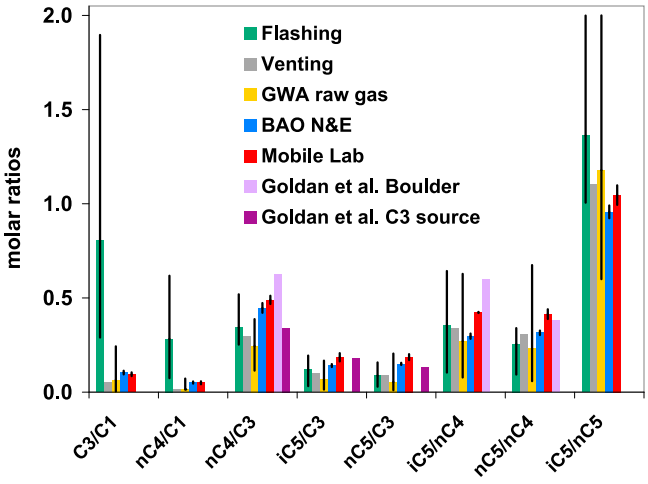

Figure 9. Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June–July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (gray) sources used by *Bar-Ilan et al.* [2008a] for the DJB WRAP Phase III emissions inventory. The error bars indicate the min and max values for the flashing emissions molar ratios. Also shown are the mean, min and max molar ratios derived from the composition analysis of gas samples collected in 2006 at 77 different gas wells in the Great Wattenberg Area (yellow) [*Colorado Oil and Gas Conservation Commission*, 2007]. *Goldan et al.* [1995] data are from a two week measurement campaign in the Foothills, west of Boulder, in February 1991 (light purple). Goldan et al. identified a "local" propane source (lower limit for correlation slope) with clear C_{4-5} alkane ratios to propane (dark purple, see also text). The error bars on the observed atmospheric molar ratios are the 2-sigma calculated for the ratios with linmix_err.pro (http://idlastro.gsfc.nasa.gov/ftp/pro/math/linmix_err.pro).

n-C_4H_{10} and the C_5H_{12} isomers do not accumulate over the continent. Instead their atmospheric mixing ratios and the slopes of correlations between different alkanes reflect mostly local or regional sources within a few days of atmospheric transport.

[60] The source responsible for the alkane enhancements observed at BAO and in multiple surveys during the Front Range Study appears to be located in the northeastern part of the Front Range region within the Denver-Julesburg Basin, so we call it the DJB source. The small differences in alkane correlation slopes for the BAO and Mobile Lab samples likely reflect differences in the emitted alkane molar ratios across this distributed source, as well as the mix of chemical ages for the air samples collected at a variety of locations and on different days.

[61] In Table 3 and Figure 4, we compare the alkane correlation slopes in the Mobile Lab flask data set with the correlation slopes in the BAO data set. To calculate the DJB source C_3H_8-to-CH_4 correlation slope from the Mobile Lab data set, we have removed air samples collected downwind of feedlots, the wastewater treatment plant, and the natural gas and propane processing plant (Figure 1). The Mobile Lab flasks C_3H_8-to-CH_4 correlation slope is 0.095 ± 0.007 ppb/ppb (R^2 = 0.76, 77 samples), similar to the slope calculated for the BAO NE wind sector data. Samples collected downwind of the natural gas processing plant exhibit variable chemical signatures, reflecting a complex mix of contributions from leaks of gas and combustion exhaust from flaring units and compressor engines.

[62] To calculate the DJB source n-C_4H_{10}-to-C_3H_8, i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes from the Mobile Lab data set, we have removed the three air samples collected downwind of the natural gas and propane processing plant (Figure 1). The C_4/C_3, i-C_5/C_3 and n-C_5/C_3 correlation slopes in the Mobile Lab data are 0.49, 0.19 and 0.19 ppb/ppb, respectively (r^2 > 0.8, 85 samples). The i-C_5/C_3 and n-C_5/C_3 correlation slopes are 40% and 30% higher, respectively, than the BAO NE sector summer slopes. If we remove the 11 data points from survey 6 samples collected in the middle of the DJB, the C_5H_{12}-to-C_3H_8 ratios are only 15% higher than calculated for the NE sector at BAO.

[63] High correlations among various alkanes were reported in this region by *Goldan et al.* [1995]. In that study, hourly air samples were analyzed with an in situ gas chromatograph deployed on a mesa at the western edge of Boulder for two weeks in February 1991. CH_4 was not measured during that study. The correlation coefficient (r^2) between C_3H_8, n-C_4H_{10}, and the C_5H_{12} isomers was around 0.86, with a clear minimum slope for the abundance ratios [see *Goldan et al.*, 1995, Figure 4]. The authors proposed that the C_4-C_6 alkanes shared one common source with propane (called the "C_3 source" in the next section and in Figure 9), with additional emissions contributing to some C_4-C_6 alkane enhancements.

4.2. Comparing the Front Range Observed Alkane Signatures With VOC Emissions Profiles for Oil And Gas Operations in the Denver-Julesburg Basin

[64] In this section we compare the alkane ratios calculated from the BAO NE wind sector and the Mobile Lab samples to emissions profiles from the DJB oil and gas exploration and production sector. Most of these profiles were provided by the WRAP Phase III inventory team, who developed total VOC and NOx emission inventories for oil and gas production and processing operation in the DJB for 2006 [*Bar-Ilan et al.*, 2008a]. Emissions and activity data were extrapolated by the WRAP Phase III inventory team to derive emission estimates for 2010 based on projected production numbers and on state and federal emissions control regulations put in place in early 2008 for oil and gas permitted activities in the DNFR NAA [*Bar-Ilan et al.*, 2008b]. The VOCs included in the inventories are: C_3H_8, i,n-C_4H_{10}, i,n-C_5H_{12} and higher alkanes, C_6H_6, toluene, ethyl-benzene, xylenes and 224-trimethylpentane. The WRAP Phase III inventories for 2006 and 2010 were only provided as total VOC and NOx emitted at the county level for all the counties in the Colorado part of the DJB. The emission estimates are based on various activity data (including the number of new wells (spuds), the total number of wells, estimates of oil, condensate and gas production, and equipment counts) and measured/reported or estimated VOC speciation profiles for the different source categories. Auxiliary material Figure S2 and *Bar-Ilan et al.* [2008a, 2008b] present more details on how the inventory emission estimates are derived.

[65] We focus primarily on flashing and venting sources here, since the WRAP Phase III inventory indicates that these two sources are responsible for 95% of the total VOC emissions from oil and gas exploration and production operations in Weld County and in the NAA [*Bar-Ilan et al.*, 2008a, 2008b] (see auxiliary material Figure S2). In 2006, all the oil produced in the DJB was from condensate wells. Condensate tanks at well pads or processing plants store a mostly liquid mix of hydrocarbons and aromatics separated from the lighter gases in the raw natural gas. Flash losses or emissions happen for example when the liquid condensate is exposed to decreasing atmospheric pressure: gases dissolved in the liquid are released and some of the heavier compounds may be entrained with these gases. Flashing emissions from condensate storage tanks are the largest source of VOCs from oil and gas operations in the DJB. In the DNFR NAA, operators of large condensate tanks have to control and report emission estimates to the Colorado Department of Public Health and the Environment (CDPHE). In 2006 and 2010 flashing emissions represented 69% and 65% respectively of the total VOC source from oil and gas exploration, production and processing operations, for the nine counties in the NAA (see auxiliary material Figure S2 and *Bar-Ilan et al.* [2008a] for more details on how the estimates are derived).

[66] Venting emissions are related to loss of raw natural gas when a new oil or gas well is drilled or when an existing well is vented (blowdown), repaired or restimulated (recompletion). Equipment at active well sites (e.g., wellhead, glycol dehydrators and pumps) or in the midstream network of compressors and pipelines gathering the raw natural gas can also leak significant amounts of natural gas. In the WRAP Phase III inventory, venting emissions represented 27% and 21% respectively of the total VOC estimated source from the NAA oil and gas operations in 2006 and 2010 (see *Bar-Ilan et al.* [2008a, 2008b] and auxiliary material Figure S2).

[67] The molar compositions of venting and flashing emissions are quite different (see auxiliary material Figure S4). Emissions from flash losses are enriched in C_{2+} alkanes compared to the raw natural gas emissions. To convert the total VOC bottom-up source into speciated emission ratio estimates, we use molar ratio profiles for both flashing and venting emissions reported in three data sets: (1) *Bar-Ilan et al.* [2008a]: mean venting profile used for the 2006 DJB inventory, also called the "Venting-WRAP" profile; (2) *Colorado Oil and Gas Conservation Commission* (*COGCC*) [2007]: composition of 77 samples of raw natural gas collected at different wells in the Greater Wattenberg Area in December 2006, also called "Venting-GWA" profiles. Note that C_6H_6 was not reported in this data set; and (3) Colorado Department of Public Health and the Environment (C. LaPlante, CDPHE, personal communication, 2011): flashing emissions profiles based on condensate composition data from 16 different storage tanks in the DJB and EPA TANK2.0 (flashing emissions model) runs.

[68] Figure 9 shows a comparison of the alkane molar ratios for the raw natural gas and flash emissions data sets with the correlation slopes derived for the Mobile Lab 2008 samples and for air samples collected at BAO in the summer months only (between August 2007 and April 2010) for the NE wind sector (see auxiliary material Table S4 to get the plotted values). The alkane correlation slopes observed at BAO and across the Northern Front Range with the Mobile Lab are all within the range of ratios reported for flashing and/or venting emissions. The C_{3-5} alkane ratios for both flashing and venting emissions are too similar for their atmospheric ratios to be useful in distinguishing between the two source processes. The ambient C_3H_8-to-CH_4 and n-C_4H_{10}-to-CH_4 molar ratios are lower than what could be expected from condensate tank flashing emissions alone, indicating that most of the CH_4 observed came from the venting of raw natural gas. In the next section, we will describe how we derive bottom-up emission estimates for CH_4 and C_3H_8 as well as three top-down emissions scenarios consistent with the observed atmospheric slopes.

[69] Figure 9 also shows the correlation slopes calculated by *Goldan et al.* [1995] for the 1991 Boulder study. These slopes compare very well with the BAO and Mobile Lab results and the oil and gas venting and flashing emissions ratios. *Goldan et al.* [1995] compared the measured C_4/C_3 and C_5/C_3 ratios for the Boulder C_3 source (see definition in section 4.1) with the ratios reported in the locally distributed pipeline-quality natural gas for February 1991, and concluded that the common C_3H_8 and higher alkane source was not linked with the local distribution system of processed natural gas. However, the composition of the raw natural gas at the extraction well is quite different from the purified pipeline-quality natural gas distributed to end-users. Processed pipeline-quality natural gas delivered throughout the USA is almost pure CH_4 [*Gas Research Institute*, 1992]. Since *Goldan et al.* [1995] did not measure CH_4 in their 1991 study, they could not determine if the atmospheric C_{3+}/C_1 alkane ratios were higher than expected in processed natural gas.

4.3. Estimation of the Alkane Source in Weld County

4.3.1. Bottom-Up Speciated Emission Estimates

[70] In this section, we derive bottom-up and top-down estimates of alkane emissions from the DJB source for Weld County. We have averaged the 2006 and 2010 WRAP Phase III total VOC emissions data [*Bar-Ilan et al.*, 2008a, 2008b] to get bottom-up estimates for the year 2008, resulting in 41.3 Gg/yr for flashing emissions and 16.8 Gg/yr for venting emissions. There are no uncertainty estimates provided in the WRAP Phase III inventory. 2006 total VOC flashing emission estimates in Weld County are based on reported emissions for controlled large condensate tanks (34.8 Gg/yr) and calculated emissions for uncontrolled small condensate tanks (5.4 Gg/yr) (see *Bar-Ilan et al.* [2008a] for more details). Uncertainties attached to these estimates may be due to inaccurate emissions factors (number of pounds of VOC flashed per tons of condensate produced) and/or inaccurate estimate of the effectiveness of emission control systems.

[71] The WRAP Phase III total VOC emission from venting sources for Weld County was calculated by averaging industry estimates of the volume of natural gas vented or leaked to the atmosphere by various processes shown in auxiliary material Figure S2 (well blowdown, well completion, pneumatic devices…). A basin-wide average of gas composition analyses provided by oil and gas producers was then used to compute a bottom-up estimate of the total mass of VOC vented to the atmosphere by oil and gas exploration, production and processing operations. Uncertainties attached to the venting source can be related to

Table 4. Bottom-Up (Inventory-Derived) Emission Estimates and Top-Down Emissions Scenarios for CH_4 and C_3H_8 in Weld County

	Bottom-Up Estimates				Top-Down Scenarios: Venting[a] (Gg/yr)			Top-Down Scenarios: TOTAL Bottom-Up Flashing + Top-Down Venting[a] (Gg/yr)			Top-Down Scenarios: Percent Of Production Vented[a,b]		
	Flashing[c] (Gg/yr)	Venting[d] (Gg/yr)	Flashing + Venting (Gg/yr)	Percent of Production Vented[e]	1	2	3	1	2	3	1	2	3
Methane	**11.2**	53.1	64.3	**1.68%**	118.4	92.5	157	**129.6**	103.7	168.2	**4.0%**	3.1%	5.3%
Min[f]	**4**	42	46		86.5	67.6	114.7	90.5	**71.6**	118.7	2.9%	**2.3%**	3.8%
Max[f]	**23**	63	86		172.6	134.9	228.9	195.6	157.9	**251.9**	5.8%	4.5%	**7.7%**
Propane	**18.3**	7.8	26.1		17.4	10.2	28	**35.7**	28.5	46.3			
Min[f]	**14**	1	15		12.7	7.5	20.5	26.7	**21.5**	34.5			
Max[f]	**24**	28	52		25.3	14.9	40.8	49.3	38.9	**64.8**			

[a]The CH_4-to-C_3H_8 molar ratio for vented natural gas is 18.75 (WRAP report estimate) for scenario 1, 15.43 for scenario 2 (median of molar ratios in GWA data set) and 24.83 for scenario 3 (mean of molar ratios in GWA data set).

[b]Using the assumptions of a CH_4 molar ratio of 77% for the vented natural gas and a molar volume for the gas of 23.6 L/mol (Pressure = 14.73 pounds per square inch and Temperature = 60°F) as used by the *EIA* [2004].

[c]The bottom-up flashing emissions for methane and propane were calculated using the 2008 estimate of total VOC flash emissions derived by averaging the WRAP estimate for 2006 and the projection for 2010 (Cf. section 4.3).

[d]The bottom-up venting emissions for methane and propane were calculated using the WRAP Phase III inventory estimate for the total volume of natural gas vented and the GWA 77 natural gas composition profiles.

[e]Using the WRAP Phase III inventory data set and assumptions, including a CH_4 mean molar ratio of 77.44% for the vented natural gas and a molar volume for the gas of 22.4 L/mol.

[f]The minimum and maximum values reported here come from the ensemble of 16 condensate tank emissions speciation profiles provided by CDPHE.

uncertainties in leak rates or intensity of out-gassing events, as well to the variability in the composition of raw natural gas, none of which were quantitatively taken into account in the WRAP Phase III inventory.

[72] Next we describe the calculations, summarized in auxiliary material Figure S5, to derive bottom-up estimates of venting and flashing emissions for the various trace gases we measured using information from the WRAP Phase III inventory and the COGCC GWA raw natural gas composition data set (Table 4 and auxiliary material Figure S6). From the total annual vented VOC source and the average vented emission profile provided by *Bar-Ilan et al.* [2008a] (auxiliary material Table S2), we derived an estimate of the volume of natural gas that we assumed is vented to the atmosphere by the oil and gas production and processing operations in Weld County. Following *Bar-Ilan et al.* [2008a] inventory data and assumptions, we used the weight fraction of total VOC in the vented gas (18.74%), the molar mass of the vented gas (21.5g/mol) and standard pressure and temperature with the ideal gas law to assume that 1 mol of raw natural gas occupies a volume 22.4 L (as was done in the WRAP Phase III inventory). The total volume of vented gas we calculate for Weld County in 2008 is 3.36 billion cubic feet (Bcf), or the equivalent of 1.68% of the total natural gas produced in the county in 2008 (202.1 Bcf). We then use the estimate of the volume of vented gas and the molar composition profiles for the 77 raw natural gas samples reported in the COGCC GWA study to compute average, minimum, and maximum emissions for CH_4, each of the C_{3-5} alkanes we measured, and C_6H_6. Using this procedure, 2008 Weld County average venting CH_4 and C_3H_8 bottom-up source estimates are 53.1 Gg/yr and 7.8 Gg/yr, respectively (Table 4).

[73] For flashing emissions, we distributed the WRAP 2008 total annual VOC source estimate (41.3 Gg/yr) using the modeled flash loss composition profiles for 16 different condensate tanks provided by the CDPHE. Average CH_4 and C_3H_8 emissions as well as the minimum and maximum estimates are reported in Table 4. The 2008 average flashing CH_4 and C_3H_8 bottom-up emission estimates are 11.2 Gg/yr and 18.3 Gg/yr, respectively (Table 4). The total flashing + venting CH_4 and C_3H_8 bottom-up estimates range from 46 to 86 Gg/yr and from 15 to 52 Gg/yr, respectively.

4.3.2. Top-Down Emissions Scenarios

[74] Finally, we use our atmospheric measurements to bring new independent constraints for the estimation of venting and flashing emissions in Weld County in 2008. The exercise consists in calculating three top-down venting emission scenarios for CH_4 and C_3H_8 (x_m, x_p: mass of methane and propane vented respectively) consistent with a mean observed CH_4-to-C_3H_8 atmospheric molar ratio of 10 ppb/ppb (Table 4) in the DJB. We assume, as done earlier in the bottom-up calculations, that the observed C_3H_8-to-CH_4 ratio in the DJB results from a combination of flashing and venting emissions. The bottom-up information used here is (1) the set of speciated flashing emissions derived earlier for the 16 condensate tanks provided by CDPHE for CH_4 and C_3H_8 $(y_m, y_p)_{\text{tank}=1,16}$, and (2) three scenarios for the basin-average raw (vented) natural gas CH_4-to-C_3H_8 molar ratio, denoted $\boldsymbol{v}_{m/p}$. The three values used for basin-average vented gas CH_4-to-C_3H_8 molar ratio are: 18.75, which is the WRAP Phase III inventory assumption (scenario 1); 15.43, which is the median of the molar ratios for the COGCC GWA 77 gas samples (scenario 2); and 24.83, which is the mean of the molar ratios for the COGCC GWA 77 gas samples (scenario 3). For each vented gas profile scenario, we use the set of 16 flash emission estimates to calculate an ensemble of venting emission estimates for CH_4 (x_m) and C_3H_8 (x_p) following the two equations below.

[75] The first equation formalizes the assumption for CH_4-to-C_3H_8 molar ratio of the vented raw natural gas, with M_m (16g/mol) and M_p (44g/mol) being the molar masses of CH_4 and C_3H_8 respectively.:

$$v_{m/p} = \frac{M_p}{M_m} \times \frac{x_m}{x_p} \tag{1}$$

[76] In the second equation, the mean observed atmospheric CH_4-to-C_3H_8 molar ratio ($a_{m/p}$ = 10 ppb/ppb)

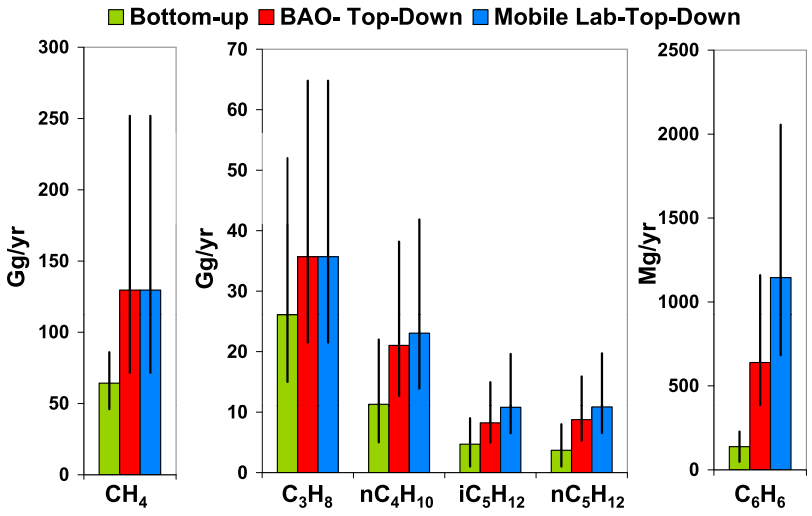

Figure 10. Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios described in Table 4.

constrains the overall ratio of methane versus propane emitted by both flashing and venting sources. Therefore, for each set of 16 bottom-up flashed emission estimates (y_m, y_p), we have:

$$\frac{M_p(x_m + y_m)}{M_m(x_p + y_p)} = a_{m/p} \tag{2}$$

[77] The analytical solutions to this set of equations are given by:

$$\begin{aligned} x_p &= \frac{1}{(v_{m/p} - a_{m/p})} \times \left(a_{m/p} \times y_p - \frac{M_p}{M_m} y_m\right) \\ x_m &= v_{m/p} \times \frac{M_m}{M_p} \times x_p \end{aligned} \tag{3}$$

[78] The average, minimum and maximum venting emission estimates, x_m and x_p, are reported for the three vented gas profile scenarios in Table 4 and Figure 10.

[79] The first goal of this top-down estimation exercise is to highlight the many assumptions required to build the bottom-up and top-down emission estimates. The choices made for the WRAP Phase III inventory or our top-down calculations are all reasonable, and the uncertainty attached to the values chosen (if available) should be propagated to calculate total uncertainty estimates for the final emission products. When the error propagation is done conservatively, the emission uncertainty is close to a factor of 2 for both CH_4 and C_3H_8. This number is much higher than the 30% uncertainty reported by the EPA for the 2009 national CH_4 source estimate from natural gas systems [*EPA*, 2011].

[80] The scenario 1 mean top-down vented CH_4 source (118.4 Gg/yr) is twice as large as the bottom-up estimate of 53.1 Gg/yr (Table 4). If we assume that 77% (by volume) of the raw gas is CH_4, an average estimate of 118.4 Gg/yr of CH_4 vented would mean that the equivalent of 4% of the 2008 natural gas gross production in Weld County was vented. It is important to note that the top-down scenarios cover a large range (67–229 Gg/yr), corresponding to between 2.3% and 7.7% of the annual production being lost to the atmosphere through venting (Table 4). The lowest estimate is, however, larger than what we derived from the WRAP Phase III bottom-up inventory (1.68%). If instead of using the *EIA* [2004] convention for the molar volume of gas (23.6 L/mol), we used the standard molar volume used by WRAP (22.4 L/mol), our top-down calculations of the volume of gas vented would be 5% lower than reported in Table 4.

[81] Emissions for the other alkanes measured are all derived from the C3H8 total sources scaled with the atmospheric molar ratios observed in the BAO NE summer samples and the Mobile Lab samples. Figure 10 shows a comparison of the bottom-up estimates and the top-down emission scenarios (mean of scenario 1 and overall minimum and maximum of the three scenarios).

[82] The main result of this exercise is that for each of the three top-down total emissions scenarios, the mean estimates for CH_4, n-C_4H_{10} and the C_5H_{12} isomers are at least 60% higher than the bottom-up mean estimates. The minimum top-down emissions scenarios are lower than (in the case of C_3H_8) or higher than (for CH_4, nC_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) the bottom-up mean estimates.

[83] To put the top-down CH_4 source estimate from oil and gas exploration, production and processing operations in perspective, we compare it with an estimate of the passive "geological" CH_4 flux over the entire DJB. *Klusman and Jakel* [1998] reported an average flux of 0.57 mg CH_4/m^2/day in the DJB due to natural microseepage of light alkanes. Multiplied by a rough upper boundary estimate of the DJB surface area (Figure 1), the estimated annual natural flux is 0.66 Gg CH_4 /yr, or less than 1% of the top-down venting source estimated for active exploration and production of natural gas in Weld County.

4.4. Benzene Sources in the Northern Front Range

[84] On-road vehicles are estimated to be the largest source of C_6H_6 in the U.S. (EPA, 2008 report on the environment,

2009, www.epa.gov/roe). Emissions from on-road and off-road vehicles and from large point sources (including chemical plants and refineries) have been regulated by the EPA for over thirty years [*Fortin et al.*, 2005; *Harley et al.*, 2006]. When motor vehicle combustion dominates emissions, such as in the BAO S and W wind sectors, C_6H_6 correlates well with CO and C_2H_2.

[85] Crude oil and natural gas production and processing emitted an estimated 8333 tonnes of benzene nationally in 2005, which represented 2% of the national total C_6H_6 source (EPA, 2008 report on the environment, 2009, www.epa.gov/roe). C_6H_6 and C_3H_8 have similar photochemical lifetimes (~3–4 days in the summer), so the observed atmospheric ratios we report in Table 3 should be close to their emission ratio if they are emitted by a common source. The strong correlation between C_6H_6 and C_3H_8 (Figure 4 and Table 3) for the BAO NE wind sector and in the DJB Mobile Lab air samples suggests that oil and gas operations could also be a non-negligible source of C_6H_6 in the Northern Colorado Front Range.

[86] The C_6H_6-to-C_3H_8 molar ratios in the flash losses from 16 condensate tanks simulated with the EPA TANK model are between 0.4 to 5.6 ppt/ppb. The C_6H_6-to-C_3H_8 molar ratio reported for vented emissions in the WRAP Phase III inventory is 5.3 ppt/ppb, based on regionally averaged raw gas speciation profiles provided by local companies [*Bar-Ilan et al.*, 2008a] (only an average profile was provided, other data is proprietary). These emission ratios are at least a factor of two lower than the atmospheric ratios measured in the Front Range air samples influenced by the DJB source (Table 3).

[87] If we use the mean C_3H_8 emission estimate for scenario 1 described in section 4.3 (35.7 Gg/yr), together with the C_6H_6-to-C_3H_8 correlation slope for the summer BAO NE wind sector data and that from the Mobile Lab samples (10.1 ppt/ppb and 17.9 ppt/ppb respectively), we derive a C_6H_6 emission estimate for the DJB source in Weld County in 2008 of 639 tonnes/yr (min/max range: 478/883 tonnes/yr) and 1145 tonnes/yr (min/max range: 847/1564 tonnes/yr), respectively. As expected, these numbers are much higher than what we derived for the bottom-up flashing and venting emissions (total of 139 tonnes/yr, min/max range of 49–229 tonnes/yr). For comparison, C_6H_6 emissions from facilities in Colorado reporting to the U.S. EPA for the Toxics Release Inventory amounted to a total of 3.9 tonnes in 2008 (EPA, Toxics Release Inventory program, 2009, data available at http://www.epa.gov/triexplorer/chemical.htm) and on–road emissions in Weld County were estimated at 95.4 tonnes/yr in 2008 (C. LaPlante, CDPHE, personal communication, 2011). Based on our analysis, oil and gas operations in the DJB could be the largest source of C_6H_6 in Weld County.

[88] More measurements are needed to further evaluate the various potential sources associated with oil and gas operations (for example, glycol dehydrators and condensate tank flash emissions). The past two iterations of the C_6H_6 emissions inventory developed by the State of Colorado for the National Emissions Inventory and compiled by the EPA do not show much consistency from one year to another. The 2008 and 2005 NEI reported very different C_6H_6 emission estimates for condensate tanks in Weld County (21.5 Mg/yr versus 1120 Mg/yr, respectively; see also auxiliary material Table S3). Estimates in the 2008 NEI are much closer to estimates provided by CDPHE (C. LaPlante, personal communication, 2011) for 2008 (21.3 Mg/yr), suggesting the 2005 NEI estimate may be flawed, even though it is in the range of our top-down estimation. We conclude that the current level of understanding of emissions of C_6H_6 from oil and gas operations cannot explain the top-down range of estimates we derive in our study, suggesting that, once again, more field measurements are needed to understand and quantify oil and gas operation sources.

5. Conclusion

[89] This study provides a regional overview of the processes impacting ambient alkane and benzene levels in northeastern Colorado in the late 2000s. We report atmospheric observations collected by two sampling platforms: a 300-m tall tower located in the SW corner of Weld County (samples from 2007 to 2010), and road surveys by a Mobile Lab equipped with a continuous methane analyzer and discrete canister sampling (June–July 2008). The analysis of the tower data filtered by wind sector reveals a strong alkane and benzene signature in air masses coming from northeastern Colorado, where the main activity producing these compounds is related to oil and gas operations over the Denver–Julesburg Fossil Fuel Basin. Using the Mobile Lab platform, we sampled air directly downwind of different methane sources (oil and gas wells, a landfill, feedlots, and a wastewater treatment plant) and collected targeted air samples in and out of plumes. The tall tower and Mobile Lab data both revealed a common source for air masses with enhanced alkanes. In the data from both platforms, the alkane mixing ratios were strongly correlated, with slight variations in the correlation slopes depending on the location and day of sampling. The alkanes did not correlate with combustion tracers such as carbon monoxide and acetylene. We hypothesize that the observed alkanes were emitted by the same source located over the Denver-Julesburg Basin, "the DJB source."

[90] The second part of the study brings in information on VOC emissions from oil and gas activities in the DJB from the detailed bottom-up WRAP Phase III inventory [*Bar Ilan et al.*, 2008a, 2008b]. We have used the total VOC emission inventory and associated emissions data for DJB condensate and gas production and processing operations to calculate annual emission estimates for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The main findings are summarized below:

1. The emissions profiles for flashing and venting losses are in good agreement with the atmospheric alkane enhancement ratios observed during this study and by *Goldan et al.* [1995] in Boulder in 1991. This is consistent with the hypothesis that the observed alkane atmospheric signature is due to oil and gas operations in the DJB.

2. The three top-down emission scenarios for oil and gas operations in Weld County in 2008 give a rather large range of potential emissions for CH_4 (71.6–251.9 Gg/yr) and the higher alkanes. Except for propane, the lowest top-down alkanes emission estimates are always larger than the inventory-based mean estimate we derived based on the WRAP Phase III inventory data and the COGCC GWA raw gas composition data set.

3. There are notable inconsistencies between our results and state and national regulatory inventories. In 2008 gas wells in Weld County represented 15% of the state's production. Based on our top-down analysis, Weld County methane emissions from oil and gas production and processing represent at least 30% of the state total methane source from natural gas systems derived by *Strait et al.* [2007] using the EPA State Inventory Tool. The methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two. Oil and gas operations are the largest source of alkanes in Weld County. They were included as a source of "total VOC" in the 2008 EPA NEI for Weld County but not in the 2005 NEI.

4. There are at least two main sources of C_6H_6 in the region: one related to combustion processes, which also emit CO and C_2H_2 (engines and mobile vehicles), and one related to the DJB alkane source. The C_6H_6 source we derived based on flashing and venting VOC emissions in the WRAP inventory (143 Mg/yr) most likely underestimates the actual total source of C_6H_6 from oil and gas operations. Our top-down source estimates for C_6H_6 from oil and gas operations in Weld County cover a large range: 385–2056 Mg/yr. Again, the lowest figure is much higher than reported in the 2008 CDPHE inventory for Weld County oil and gas total point sources (61.8 Mg/yr).

5. Samples collected at the BAO tall tower or while driving around the Front Range reflect the emissions from a complex mix of sources distributed over a large area. Using a multispecies analysis including both climate and air quality relevant gases, we can start unraveling the contributions of different source types. Daily multispecies measurements from the NOAA collaborative network of tall towers in the U.S. provide a unique opportunity to understand source chemical signatures in different airsheds and how these emissions may change over time.

6. More targeted multispecies well-calibrated atmospheric measurements are needed to evaluate current and future bottom-up inventory emissions calculations for the fossil fuel energy sector and to reduce uncertainties on absolute flux estimates for climate and air quality relevant trace gases.

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Regular Article

Methane emissions estimate from airborne measurements over a western United States natural gas field

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Abstract

[1] Methane (CH_4) emissions from natural gas production are not well quantified and have the potential to offset the climate benefits of natural gas over other fossil fuels. We use atmospheric measurements in a mass balance approach to estimate CH_4 emissions of $55 \pm 15 \times 10^3$ kg h^{-1} from a natural gas and oil production field in Uintah County, Utah, on 1 day: 3 February 2012. This emission rate corresponds to 6.2%–11.7% (1σ) of average hourly natural gas production in Uintah County in the month of February. This study demonstrates the mass balance technique as a valuable tool for estimating emissions from oil and gas production regions and illustrates the need for further atmospheric measurements to determine the representativeness of our single-day estimate and to better assess inventories of CH_4 emissions.

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ENERGY

Methane leaks erode green credentials of natural gas

Losses of up to 9% show need for broader data on US gas industry's environmental impact.

BY JEFF TOLLEFSON

Scientists are once again reporting alarmingly high methane emissions from an oil and gas field, underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system.

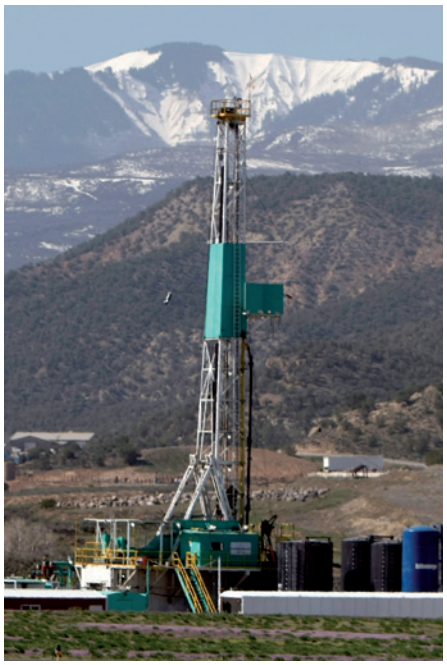
The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study[1] suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.

Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.

"We were expecting to see high methane levels, but I don't think anybody really comprehended the true magnitude of what we would see," says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA's Earth System Research Laboratory in Boulder.

Whether the high leakage rates claimed in Colorado and Utah are typical across the US natural-gas industry remains unclear. The NOAA data represent a "small snapshot" of a much larger picture that the broader scientific community is now assembling, says Steven Hamburg, chief scientist at the Environmental Defense Fund (EDF) in Boston, Massachusetts.

The NOAA researchers collected their data in February as part of a broader analysis of air pollution in the Uinta Basin, using ground-based equipment and an aircraft to make detailed measurements of various pollutants, including methane concentrations. The researchers used atmospheric modelling to calculate the level of methane emissions required to reach those concentrations, and then compared that with industry data on gas production to obtain the percentage escaping into the atmosphere through venting and leaks.



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

J. DAVID ZALUBOWSKI/AP

The results build on those of the earlier Colorado study[1] in the Denver–Julesburg Basin, led by NOAA scientist Gabrielle Pétron (see *Nature* **482,** 139–140; 2012). That study relied on pollution measurements taken in 2008 on the ground and from a nearby tower, and estimated a leakage rate that was about twice as high as official figures suggested. But the team's methodology for calculating leakage — based on chemical analysis of the pollutants — remains in dispute. Michael Levi, an energy analyst at the Council on Foreign Relations in New York, published a peer-reviewed comment[2] questioning the findings and presenting an alternative interpretation of the data that would align overall leakage rates with previous estimates.

Pétron and her colleagues have a defence of the Colorado study in press[3], and at the AGU meeting she discussed a new study of the Denver–Julesburg Basin conducted with scientists at Picarro, a gas-analyser manufacturer based in Santa Clara, California. That study relies on carbon isotopes to differentiate between industrial emissions and methane from cows and feedlots, and the preliminary results line up with their earlier findings.

A great deal rides on getting the number right. A study[4] published in April by scientists at the EDF and Princeton University in New Jersey suggests that shifting to natural gas from coal-fired generators has immediate climatic benefits as long as the cumulative leakage rate from natural-gas production is below 3.2%; the benefits accumulate over time and are even larger if the gas plants replace older coal plants. By comparison, the authors note that the latest estimates from the US Environmental Protection Agency (EPA) suggest that 2.4% of total natural-gas production was lost to leakage in 2009.

To see if that number holds up, the NOAA scientists are also taking part in a comprehensive assessment of US natural-gas emissions, conducted by the University of Texas at Austin and the EDF, with various industry partners. The initiative will analyse emissions from the production, gathering, processing, long-distance transmission and local distribution of natural gas, and will gather data on the use of natural gas in the transportation sector. In addition to scouring through industry data, the scientists are collecting field measurements at facilities across the country. The researchers expect to submit the first of these studies for publication by February, and say that the others will be complete within a year.

In April, the EPA issued standards intended to reduce air pollution from hydraulic-fracturing operations — now standard within the oil and gas industry — and advocates say that more can be done, at the state and national levels, to reduce methane emissions. "There are clearly opportunities to reduce leakage," says Hamburg. ■

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4. Alvarez, R. A., Pacala, S. W. Winebrake, J. J., Chameides, W. L. & Hamburg, S. P. *Proc. Natl Acad. Sci. USA* **109,** 6435–6440 (2012).

Quantifying sources of methane using light alkanes in the Los Angeles basin, California

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Abstract

Methane (CH_4), carbon dioxide (CO_2), carbon monoxide (CO), and C_2–C_5 alkanes were measured throughout the Los Angeles (L.A.) basin in May and June 2010. We use these data to show that the emission ratios of CH_4/CO and CH_4/CO_2 in the L.A. basin are larger than expected from population-apportioned bottom-up state inventories, consistent with previously published work. We use experimentally determined CH_4/CO and CH_4/CO_2 emission ratios in combination with annual State of California CO and CO_2 inventories to derive a yearly emission rate of CH_4 to the L.A. basin. We further use the airborne measurements to directly derive CH_4 emission rates from dairy operations in Chino, and from the two largest landfills in the L.A. basin, and show these sources are accurately represented in the California Air Resources Board greenhouse gas inventory for CH_4. We then use measurements of C_2–C_5 alkanes to quantify the relative contribution of other CH_4 sources in the L.A. basin, with results differing from those of previous studies. The atmospheric data are consistent with the majority of CH_4 emissions in the region coming from fugitive losses from natural gas in pipelines and urban distribution systems and/or geologic seeps, as well as landfills and dairies. The local oil and gas industry also provides a significant source of CH_4 in the area. The addition of CH_4 emissions from natural gas pipelines and urban distribution systems and/or geologic seeps and from the local oil and gas industry is sufficient to account for the differences between the top-down and bottom-up CH_4 inventories identified in previously published work.

1. Introduction

In California, methane (CH_4) emissions are regulated by Assembly Bill 32, enacted into law as the California Global Warming Solutions Act of 2006, requiring the state's greenhouse gas (GHG) emissions in the year 2020 not to exceed 1990 emission levels. To this end, the California Air Resources Board (CARB) was tasked with compiling and verifying an inventory of GHG emissions for the state. Two published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010] have concluded that atmospheric emissions of CH_4 in the Los Angeles (L.A.) area were greater than expected from a per capita apportionment of the statewide 2006 CARB GHG inventory and from a bottom-up accounting of CH_4 sources, respectively.

Several recent works have estimated CH_4 emissions to the South Coast Air Basin (SoCAB; Fig. 1a), which are summarized in Table 1. *Wunch et al.* [2009] used a Fourier transform infrared spectrometer at the Jet Propulsion Laboratory (JPL) in Pasadena, California to measure vertically-integrated total column enhancement ratios of CH_4 relative to CO and to CO_2. The observed column enhancement ratios, multiplied by CARB inventory values of CO for 2008 and an average of 2006 CARB GHG inventory and 2005 Emission Database for Global Atmospheric Research (EDGAR) for CO_2, were used to derive a lower limit to CH_4 emissions of 400 ± 100 Gg CH_4/yr (based on CO) or 600 ± 100 Gg CH_4/yr (based on CO_2) for the SoCAB. One reason for the discrepancy in their top-down analysis was that their observed CO/CO_2 enhancement ratio of 11 ± 2 ppb CO/ppm CO_2 was greater than the 8.6 ppb CO/ppm CO_2 calculated from the inventories. *Wunch et al.* [2009] contrasted these top-down assessments to a bottom-up estimate of 260 Gg CH_4/yr using the statewide 2006 CARB GHG inventory

apportioned by population after removal of agricultural and forestry emissions, and concluded that 140 – 340 Gg CH_4/yr were not accounted for in the CARB CH_4 inventory for the SoCAB.

Hsu et al. [2010] took a similar top-down approach and used observed atmospheric enhancement ratios of CH_4 to CO from *in situ* whole air samples taken at Mt. Wilson (34.22° N, 118.06° W, 1770 m above sea level), scaled by the projected CARB CO inventory for 2008, to derive CH_4 emissions of 200 ± 10 Gg CH_4/yr for just the Los Angeles (L.A.) County (Figure 1b) portion of the SoCAB (L.A. County ∩ SoCAB). They used methods prescribed by the Intergovernmental Panel for Climate Change (IPCC) to create the CARB GHG inventory and reached a bottom-up estimate of 140 Gg CH_4/yr, or 60 Gg less than their top-down calculation for the L.A. County portion of the SoCAB. *Hsu et al.* [2010] used higher spatial resolution emissions data from CARB to construct their bottom-up inventory, and therefore did not have to rely on population apportionment methods used by *Wunch et al.* [2009].

The difference between the top-down CH_4 emissions reported by *Wunch et al.* [2009] and by *Hsu et al.* [2010] (400 Gg and 200 Gg, respectively, both based on the CARB CO inventory) are in part due to the different geographic areas for which they calculate CH_4 emissions, and in part due to differences in observed CH_4/CO enhancements between these two studies: 0.66 ± 0.12 mol/mol for *Wunch et al.* [2009] [*Wennberg et al.*, 2012] and 0.52 ± 0.02 mol/mol for *Hsu et al*. [2010]. Both works suggested that fugitive losses of natural gas (NG) could be the source of the CH_4 missing from the bottom-up inventories.

More recently, *Townsend-Small et al.* [2012] analyzed stable CH_4 isotope ratios in atmospheric samples taken at Mt. Wilson and elsewhere in the western L.A. basin and showed they were consistent with isotope ratios in natural gas sources.

Wennberg et al. [2012] used the different atmospheric ethane/CH_4 enhancement ratios observed from research aircraft during the Arctic Research of the Composition of the Troposphere from Aircraft and Satellites (ARCTAS) field project in 2008 and the California Research at the Nexus of Air Quality and Climate Change (CalNex) field project [*Ryerson et al.*, in review] in 2010 to estimate an upper limit of 390 Gg CH_4/yr from natural gas leakage in the SoCAB. Further, their top-down analysis resulted in a calculated total emission of 440 Gg CH_4/yr in the SoCAB. *Wennberg et al.* [2012] also recalculated the data used by *Hsu et al.* [2010] to derive CH_4 emissions for the entire SoCAB, and calculated a SoCAB CH_4 emission from 2008 using data from ARCTAS. The results are summarized in Table 1.

Here we use ambient measurements in the SoCAB taken in May and June 2010 aboard the National Oceanic and Atmospheric Administration (NOAA) P-3 research aircraft during the CalNex field study to derive CH_4 emissions from the SoCAB using methods different from *Wennberg et al.* [2012]. We further examine CH_4 emissions from landfills and dairy farms in the SoCAB identified in the bottom-up CH_4 inventories reported by *Hsu et al.* [2010] and *Wennberg et al.* [2012]. We then expand on these previous studies by examining light alkane emissions from Los Angeles area data sets. In addition to CH_4 and ethane, we examine propane, *n*- and *i*-butane, and *n*- and *i*-pentane measurements to derive emissions of each of these light alkanes in the SoCAB, and use them in a system of linear equations to further quantify the source apportionment of CH_4 in the L.A. basin.

2. Measurements

We use trace gas measurements from a subset of platforms and sites from the CalNex field study. The NOAA P-3 research aircraft flew all or parts of 16 daytime flights in and around the L.A. basin. Two independent measurements of CH_4 and CO_2 were made aboard the aircraft by wavelength-scanned cavity ring-down spectroscopy (WS-CRDS; Picarro 1301-m) [*Peischl et al.*, 2012], and by quantum cascade laser direct absorption spectroscopy (QCLS) [*Kort et al.*, 2011]. Imprecision of the 1-Hz Picarro CH_4 measurement is ± 1.4 ppbv (all uncertainties herein are 1-σ) and inaccuracy is estimated at ± 1.2 ppbv. Imprecision of the 1-Hz QCLS CH_4 measurement is ±1 ppbv and inaccuracy is estimated at ± 15 ppbv. Imprecision of the 1-Hz Picarro CO_2 measurement is ± 0.14 ppmv and inaccuracy is estimated at ± 0.12 ppmv. Imprecision of the 1-Hz QCLS CO_2 measurement is ± 0.05 ppmv and inaccuracy is estimated at ± 0.10 ppmv. All CH_4 and CO_2 measurements are reported as dry air mole fractions. For this work, CH_4 and CO_2 data from the Picarro instrument are used, and QCLS CH_4 data from May 8 are used when the Picarro instrument was not operating. The 1-Hz CO data used in this analysis were measured by vacuum ultraviolet fluorescence spectroscopy [*Holloway et al.*, 2000]. Imprecision of the 1-Hz CO data is ± 1 ppbv; inaccuracy is estimated at ± 5%. C_2 to C_5 alkanes, and their structural isomers, were measured in whole air samples [*Colman et al.*, 2001], periodically filled during flight. Imprecision of these alkane measurements is ±5%; inaccuracies are estimated at ±10%. Wind measurements were derived from various sensors aboard the NOAA P-3; the uncertainty of the 1-Hz wind speed is estimated to be ± 1 m/s. Sensors aboard the NOAA P-3 also measured relative humidity, ambient temperature, and potential temperature with an estimated 1-Hz uncertainty of ± 0.5° C, ± 0.5° C, and ± 0.5 K, respectively.

At the CalNex Pasadena ground site, located on the California Institute of Technology (Caltech) campus, measurements of C_2–C_5 alkanes were made by a gas chromatograph-mass spectrometer (GC-MS) on 5 minute integrated samples taken every half hour [*Gilman et al.*, 2010]. Imprecision of these measurements are ±8% for ethane and ±6% for propane; inaccuracy is estimated at ± 15% for each. Data from the ground site were taken between 15 May and 15 June, 2010. CH_4 was not measured at the Pasadena ground site.

Additionally, whole-air flask samples were taken twice daily at the Mount Wilson Observatory (MWO) for most days during May and June 2010, and analyzed for a variety of trace gas species, including CH_4, CO_2, CO, and hydrocarbons [*Dlugokencky et al.*, 2011; *Conway, et al.*, 2011; *Novelli et al.*, 2010]. Imprecision of the CH_4 measurement is ± 1 ppb; imprecision of the CO_2 measurement is ± 0.1 ppm; imprecision of the CO measurement is ± 1 ppbv, and inaccuracy of CO measurement is estimated to be ± 5%.

We also analyze alkane data from whole air samples taken in the L.A. basin prior to 2010. Ethane and propane were measured in whole air samples taken on four flights in L.A. aboard an instrumented National Aeronautics and Space Administration (NASA) DC-8 research aircraft during ARCTAS in June 2008 [*Simpson et al.*, 2010]. Ethane and propane were also measured on one flight in L.A. aboard the NOAA P-3 during the Intercontinental Transport and Chemical Transformation (ITCT) study in May 2002 [*Schauffler et al.*, 1999].

3. Methods

To ensure sampling from the L.A. basin, we consider aircraft data collected between 33.6 and 34.3° N latitude and 118.5 and 116.8° W longitude (Figure 1d, dashed box) in the following analysis. Aircraft data were further limited to samples taken between 1000 and 1700 PST,

between 200 and 800 m above ground, and below 1400 m above sea level, to ensure daytime sampling was within the well-mixed boundary layer, which averaged 1000 ± 300 m above ground level for the daytime L.A. flights [*Neuman et al.*, 2012]. Ground-based measurements at Pasadena were retained between 1000 and 1700 PST to ensure sampling of a well-mixed daytime boundary layer. For MWO measurements, afternoon samples, which typically occurred between 1400 and 1500 PST, were retained to capture upslope transportation from the L.A. basin [*Hsu et al.*, 2010]. Linear fits to the data presented below are orthogonal distance regressions [*Boggs et al.*, 1989] weighted by instrument imprecision [*Bevington*, 1969] (weighted ODR). The total uncertainty in the fitted slope is calculated by quadrature addition of the fit uncertainty and the measurement uncertainties.

For flux determinations, crosswind transects were flown downwind of known point sources. Enhancements of CH_4 above background levels were integrated along the flight track, and a flux was calculated using the following equation:

$$flux = v\ cos(\alpha) \int_{Z_0}^{Z_1} n(z)\,dz \int_{-y}^{y} X_m(y)\,dy \qquad (1)$$

where v cos(α) is the component of the average wind velocity normal to the flight track, n is the number density of the atmosphere, z_0 is the ground level, z_1 is the estimated boundary layer height, and X_m is the measured mixing ratio enhancement above the local background along the flight track [*White et al.*, 1976; *Trainer et al.*, 1995; *Ryerson et al.*, 1998; *Nowak et al.*, 2012]. Boundary layer heights are estimated from vertical profiles of relative humidity, ambient temperature, and potential temperature made prior to and after the crosswind transects.

We assume the plume is vertically homogeneous within the mixed layer at the point of measurement and the wind velocity is constant between emission and measurement. We estimate the uncertainty in these assumptions, combined with the uncertainties of the wind speed, wind direction, temperature, and integrated atmospheric enhancements, to be ± 50% for the plumes studied here [*Nowak et al.*, 2012]. Weighted averages of the fluxes are calculated following *Taylor* [1997]. When calculating the CH_4 flux from dairies, CH_4 variability immediately upwind of the dairies is sufficiently large to complicate interpolation from the downwind local background. To account for this, we take the weighted ODR slope of CH_4/CO immediately upwind, multiply this ratio by the measured CO downwind of the dairies, and integrate the plume CH_4 enhancement calculated from CO ($CO \times [CH_4/CO]_{upwind}$), similar to the integrations performed by *Nowak et al.* [2012]. This assumes the dairies emit a negligible amount of CO.

As with previously published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010; *Wennberg et al.*, 2012], we estimate total CH_4 emissions in the SoCAB by multiplying enhancement ratios of CH_4 to CO and CO_2 by inventory estimates of CO and CO_2 for that region:

$$E_{CH4} = \left(\frac{CH_4}{X}\right)_{ODR\ slope} \times \left(\frac{MW_{CH4}}{MW_X}\right) \times E_X \qquad (2)$$

where E_{CH4} is the emission of CH_4, X is either CO or CO_2, MW is the molecular weight, and E_X is the inventory emission value of either CO or CO_2. Although not necessarily emitted from the same sources, we assume emissions of CH_4, CO, and CO_2 are well-mixed by the time they are sampled from the NOAA P-3.

We use the following latest-available inventories for our analysis below: the 2010 CARB emissions inventory for CO projected from the base-year 2008 inventory (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php), and the 2009 CARB GHG inventory (http://www.arb.ca.gov/cc/inventory/data/data.htm). Both inventories were accessed in November 2012.

CARB projects the total 2010 annually averaged CO emissions in the SoCAB at 979 Gg CO/yr (Table 2). We use the annually averaged CARB inventory that excludes biomass burning CO emissions because no known biomass burning events were observed in the L.A. basin during CalNex. This estimate is 4% less than the summertime CO inventory without biomass burning emissions, and approximately 6% less than the annually averaged CO inventory including biomass burning emissions used by *Wennberg et al.* [2012]. To estimate 2010 CH_4 emissions in the SoCAB using the 2009 CARB GHG inventory, we follow the method used by *Wunch et al.* [2009], and take the total statewide emission of 1525 Gg CH_4/yr, less agricultural and forestry CH_4 emissions of 898 Gg CH_4/yr, then apportion the remainder by population. In 2010, the SoCAB comprised 43% of California's population (http://www.arb.ca.gov/app/emsinv/trends/ems_trends.php). However, unlike *Wunch et al.* [2009], we include SoCAB dairy emissions of 31.6 Gg CH_4/yr, calculated in section 4.3 below. Therefore, we attribute a total of 301 Gg CH_4/yr to the SoCAB based on the 2009 CARB GHG inventory (Table 2).

According to CARB's mobile source emission inventory (EMFAC 2011) for the Los Angeles County portion of the SoCAB (http://www.arb.ca.gov/jpub/webapp//EMFAC2011WebApp/emsSelectionPage_1.jsp),

mobile source CO_2 emissions remained essentially unchanged between 2009 and 2010 (39.94 versus 39.95 Tg CO_2/yr). Additionally, the statewide CARB GHG inventory for CO_2, with out-of-state electricity generation emissions removed, decreased by less than 2% between 2008 and 2009. Therefore, we assume errors due to sampling year are negligible in examining the CO_2 emission inventories in the SoCAB from 2009–2010. To estimate 2010 CO_2 emissions in the SoCAB using the 2009 CARB GHG inventory, we take the total statewide emission of 465.7 Tg CO_2/yr, subtract out-of-state electricity generation of 47.9 Tg CO_2/yr, then apportion the remainder by population. We therefore attribute 180 Tg CO_2/yr to the SoCAB using the 2009 CARB GHG inventory (Table 2). We do not compare to the Vulcan CO_2 inventory [*Gurney et al.*, 2009] because at present it is only available for the 2002 reporting year.

4. Results and Discussion

4.1. Total derived emission of CH_4 in L.A. and comparison to inventories

In this section, we use P-3 measurements of CH_4, CO, and CO_2 to calculate enhancement ratios representative of the integrated emissions from the L.A. basin. We then use tabulated CO and CO_2 emissions taken from the CARB inventories to derive total CH_4 emissions based on enhancement ratios observed in CalNex, and compare to earlier estimates of total CH_4 emissions in L.A.

Figure 1c shows known stationary sources of CH_4 in the L.A. area, which include landfills, dairies, wastewater treatment facilities, and oil fields, as well as the location of measurement sites used in this study. Dairy sources are sized by estimated CH_4 emissions from enteric fermentation, as explained in section 4.3. Landfills are sized by CH_4 emissions from the 2008 CARB GHG inventory (L. Hunsaker, personal communication, 2011).

Point sources are sized by 2009 CARB individual facility CH_4 emissions (https://ghgreport.arb.ca.gov/eats/carb/index.cfm), but do not stand out in the map due to their low CH_4 emissions relative to the landfills and dairies. Figure 1d shows the locations of daytime boundary-layer CH_4 data from the P-3, colored by observed mixing ratio, that were retained for the analysis as described previously. The largest concentrations of CH_4 were typically encountered along the mountains at the north edge of the L.A. basin, likely driven by transport of air within the basin, as typical daytime winds in the L.A. basin were from the west and southwest during May and June 2010 [*Washenfelder et al.*, 2011]. CalNex CH_4 data are plotted against observed CO in Figure 2a. Weighted ODR fits to these data resulted in derived enhancement ratios of 0.74 ± 0.04 and 0.68 ± 0.03 ppbv CH_4/ppbv CO from the NOAA P-3 and MWO, respectively. We note that the same CH_4/CO enhancement ratio of 0.74 ± 0.03 was reported by *Wennberg et al.* [2012] using the CalNex P-3 data with different selection criteria. We include box and whisker plots in Figure 2a to show that the weighted ODR fit to the data is insensitive to the relatively few data points of higher CH_4. The ratio calculated from the CARB inventory (Table 2) is 0.54 ppb CH_4/ppb CO, and is displayed for comparison.

CalNex CH_4 data are plotted against observed CO_2 in Figure 2b. The slope from a weighted ODR of P-3 data is 6.70 ± 0.01 ppb CH_4/ppm CO_2 and of MWO data is 6.60 ± 0.04 ppb CH_4/ppm CO_2. The ratio of the CARB inventories from Table 2 is 4.64 ppb CH_4/ppm CO_2, and is displayed for comparison. In this case, because CH_4 and CO_2 are measured with high precision and accuracy, the largest uncertainties in interpreting the slope as an emissions ratio are likely determined by the extent of mixing of emissions from different sources within the Los Angeles air shed. Similarly, Figure 2c shows a correlation plot of CO against CO_2.

The slope from a weighted ODR of P-3 data is 9.4 ± 0.5 ppb CO/ppm CO_2 and of MWO data is 10.4 ± 0.5 ppb CO/ppm CO_2. The ratio of the CARB inventories from Table 2 is 8.5 ppb CO/ppm CO_2, and is plotted for comparison. We estimate a ± 7.5% uncertainty in each of the CARB CO and CO_2 inventories, which is sufficient to explain the difference between the CO/CO_2 enhancement ratio measured from the NOAA P-3 and the ratio calculated from the CARB inventories. Quantitative agreement between emission ratios derived from P-3 and MWO data (Figures 2a–c) is likely due to the fact that the transport within the basin was driven by the land-sea breeze, meaning typical daytime winds in the Pasadena area near Mt. Wilson were from the southwest [*Washenfelder et al.*, 2011]. This transport, and the highest values of CH_4 and CO_2 in the P-3 data that are not seen at MWO (Figures 2a and b), also suggests that MWO preferentially samples the western part of the L.A. basin [*Hsu et al.*, 2009]. We therefore use enhancement ratios determined from the NOAA P-3 data to derive CH_4 emissions from the entire basin.

We note that the ratio of the latest CARB CO and CO_2 inventories (Table 2) are in better agreement with ambient enhancement ratios in the CalNex data than was the case for *Wunch et al.* [2009]. This is likely due to either improved CARB inventories, the present use of a basin-wide data set to determine basin-wide emission ratios, or both.

With the slopes and inventory values quantified, we next derive a CH_4 emission using equation (2). Using the CH_4/CO slope derived from the weighted ODR fit to the 2010 NOAA P-3 data and the projected 2010 CARB annually-averaged CO emission inventory in equation (2) yields an estimated SoCAB emission of 410 ± 40 Gg CH_4/yr. The stated uncertainty is the quadrature propagation of the measurement uncertainty, errors on the slope of the ODR fit to P-3

data, and an estimated uncertainty in the CARB CO inventory. We note our derived emission of 410 ± 40 Gg CH_4/yr is similar to that derived from the P-3 data by *Wennberg et al.* [2012], which was 440 ± 100 Gg CH_4/yr using different selection criteria. It is further consistent with the emission derived by *Wunch et al.* [2009] of 400 ± 100 Gg CH_4/yr, which assumed a CARB CO inventory uncertainty of 15%. We also determine CH_4 emissions using estimates of CO_2 emissions in the SoCAB. P-3 measurements of the CH_4/CO_2 enhancement ratio observed during CalNex and SoCAB CO_2 emissions inferred from the 2009 CARB GHG inventory result in a derived CH_4 emission rate of 440 ± 30 Gg CH_4/yr, with the stated uncertainties determined by quadrature propagation of the measurement uncertainty, errors on the slope of the ODR fit to P-3 data, and an estimated uncertainty in the CARB CO_2 inventory. This value, based on the CO_2 inventory, is consistent with that derived using P-3 measurements and the CO inventory, further supporting both our assessment of uncertainties in the CARB CO and CO_2 inventories, and our assumption of sampling well-mixed emissions in the SoCAB, since any outlying CH_4 data do not affect the overall emission estimates significantly.

The derived 2010 top-down SoCAB CH_4 emission of 410 and 440 Gg CH_4/yr reported here using the CARB CO or CO_2 inventories, respectively, are in quantitative agreement, in contrast to that reported for 2008 [*Wunch et al.*, 2009]. The 2010 estimates are a factor of 1.35 to 1.45 greater than the modified population-apportioned 2009 CARB GHG inventory value of 301 Gg CH_4/yr (Table 2). A concurrent inverse modeling study by *Brioude et al.* [2012] has found no statistical difference between the total SoCAB CO emissions reported by CARB for 2010 and a top-down approach that estimated CO emissions in the SoCAB region using the same CO measurements used in this paper. For this reason, and for consistency with published works [*Wunch et al.*, 2009; *Hsu et al.*, 2010; *Wennberg et al.*, 2012],

we use 410 ± 40 Gg CH_4/yr from the top-down CH_4 assessment based on 2010 P-3 measured CH_4/CO enhancement ratios and the CARB CO inventory for the remainder of our analysis.

4.2. Methane emissions from L.A. basin landfills

Landfills are the largest non-fossil fuel CH_4 emission source in the bottom-up inventories compiled by *Hsu et al.* [2010] and by *Wennberg et al.* [2012], but these two studies disagree on the magnitude of this source. *Hsu et al.* [2010] estimated annual emissions from landfills totaled 90 Gg CH_4/yr from the Los Angeles County portion of the South Coast Air Basin. *Wennberg et al.* [2012] reported landfill emissions of just 86 Gg CH_4/yr for the entire South Coast Air Basin. However, that number is too low due to an error in their gridded landfill emissions inventory [*P. Wennberg,* personal communication, 2012] and is discarded in the following analysis.

In the CARB GHG inventory, CH_4 emissions are calculated for individual landfills using methods prescribed by the IPCC and summed over all landfills to estimate a statewide total. Annual CH_4 emission values for individual landfills were obtained directly from CARB [*L. Hunsaker,* personal communication, 2011] to facilitate direct comparison to the P-3 data from CalNex. We use the P-3 data to calculate emissions from two of the largest CH_4-emitting landfills in the statewide GHG inventory, both of which are located in the SoCAB.

The first landfill results we examine are from the Olinda Alpha landfill (33.934° N, 117.841° W) in Brea, Orange County, California. The NOAA P-3 flew five daytime boundary-layer transects on five different days downwind of this landfill (Figure 3), and a CH_4 emission flux was determined for each transect using equation (1). The results are summarized in Table 3.

For the three transects when both the WS-CRDS and QCLS CH_4 instruments were sampling ambient air, flux determinations using these independent CH_4 measurements agreed within 3%. In these cases, the flux was averaged and reported in Table 3. Three nearby CH_4 point sources are identified in the 2009 CARB GHG inventory: an oil and gas field power plant, which burns natural gas for fuel; the landfill power plant at Olinda Alpha, which burns landfill gas for fuel; and general stationary combustion from the landfill operations. Inventory data suggest that these three sources together emit between 0.0004 and 0.0015 Gg CH_4/yr, negligible amounts relative to CH_4 emitted directly from the landfill. On 19 May, the NOAA P-3 sampled plumes from the nearby oil and gas power plant and the landfill's power plant, both of which burn natural gas as fuel (Figure 3c). A large spike in CO_2, some CH_4, and perhaps a small amount of CO were encountered in the landfill power plant plume. However, downwind of the landfill in the large plume of CH_4, the CO_2 enhancement does not stand out significantly above the background variability. Therefore, our analysis of P-3 data supports the conclusion from the inventory that landfill CH_4 emissions dominate the observed plume enhancements downwind of Olinda Alpha landfill. Using NOAA P-3 CH_4 data from all five transects, we directly calculate a weighted average CH_4 emission flux via equation (1) of $(1.49 \pm 0.35) \times 10^{25}$ molecules/s, equal to 12.5 ± 2.9 Gg CH_4/yr assuming a constant emission, where the weights are the 50% uncertainty of each determination. For comparison, the CARB GHG inventory emission estimate from the Olinda Alpha landfill is 11.0 Gg/yr for 2008, showing agreement within the errors of the direct estimate using P-3 airborne data.

The second landfill results we examine in-depth are from the Puente Hills landfill (34.020° N, 118.006° W) in City of Industry, Los Angeles County, California. Of all California landfills, Puente Hills is the largest emitter of CH_4 in the 2008 CARB GHG inventory.

Nearby sources of CH_4 in the 2008 CARB GHG inventory include the Puente Hills power plant (0.00045 Gg CH_4/yr) and the Savage Hills Canyon landfill (1.1 Gg CH_4/yr), both of which are small relative to the CARB GHG inventory of 39 Gg CH_4/yr emission rate for Puente Hills. The NOAA P-3 conducted three daytime boundary layer plume transects from which we determine an average emission flux of $(4.06 \pm 1.18) \times 10^{25}$ molecules/s, which extrapolates to 34.0 ± 9.9 Gg CH_4/yr assuming a constant emission (Table 3). Similar to the findings for Olinda Alpha, the CARB GHG inventory of 39 Gg CH_4/yr for the Puente Hills landfill is in agreement within the errors of the direct estimate using P-3 airborne data.

Quantitative agreement between CH_4 flux estimates from the NOAA P-3 and the 2008 CARB GHG inventory for these two examples supports the use of that inventory to quantify total CH_4 emissions from landfills in the South Coast Air Basin. According to the 2008 CARB GHG inventory, CH_4 emissions from landfills totaled 117 Gg CH_4/yr in the L.A. County portion of the SoCAB, 30% higher than the 90 Gg CH_4/yr for the same geographic area using the CARB GHG inventory in 2008 reported by *Hsu et al.* [2010], which we attribute to different versions of the CARB GHG inventory.

The 2008 CARB GHG inventory further predicts an emission from landfills of 164 Gg CH_4/yr for the entire SoCAB. On the basis of the agreement with the CARB inventory described above for the emission rates from the two landfills quantified directly by the CalNex P-3 data (50 Gg CH_4/yr, or 30% of the inventory total for the SoCAB), we assume the remaining CARB landfill CH_4 emission estimates are accurate.

4.3. Methane emissions from L.A. basin dairies

Salas et al. [2008] published dairy locations in California for the year 2005, with an estimate of dairy cow population for each. The locations are plotted as filled yellow circles in Figure 1c, and sized by the expected CH_4 emission from enteric fermentation according to the 2009 CARB GHG inventory (144 kg CH_4 per cow per year). According to *Salas et al.* [2008], all dairies in San Bernardino and Riverside counties were also located in the SoCAB, and 87% of the dairy cows in the SoCAB in 2005 were located in the Chino area (the large grouping of dairies in Figure 1c). The Chino-area dairy operations, which at one time were distributed across the Riverside-San Bernardino county line in satellite images, now appear to be located mainly in San Bernardino County as the Riverside dairies have been converted to residential neighborhoods (*e.g.*, see Google Earth historical imagery since 2000). This declining number of dairies is confirmed by the United States Department of Agriculture (USDA) (http://www.nass.usda.gov/Statistics_by_State/California/Publications/County_Estimates/201005lvscef.pdf), which reports a decrease in dairy cows in San Bernardino and Riverside Counties from 200,000 head in 2005 to 137,500 head in 2010. In addition to dairy cows, dairies also stock immature heifers. Further, there are beef operations in the SoCAB, but these are negligible compared to the San Bernardino and Riverside dairy populations. According to the USDA, there were a total of 431,000 cattle in San Bernardino and Riverside counties in 2005, and 295,000 cattle in 2010. For both years, dairy cows represented approximately 46.5% of the cattle population in the SoCAB. From these dairy and cattle populations, we construct a bottom-up emissions inventory for the SoCAB using the same emission factors as the CARB GHG inventory.

We begin with CH_4 emissions from enteric fermentation. We assign to each of the 137,500 dairy cows in the SoCAB an emission factor of 144 kg CH_4/yr. We assume the remaining 157,500 head are dairy replacements, and assign each an emission factor of 57.7 kg CH_4/yr, or the average emission factor for 0–1 and 1–2 year old dairy replacements in the CARB GHG inventory. We calculate a total of 28.9 Gg CH_4/yr emitted solely from enteric fermentation in the SoCAB.

In addition to enteric fermentation, manure management practices have a substantial effect on CH_4 emissions from livestock operations. In the L.A. basin, dairies typically practice solid storage (http://www.aqmd.gov/rules/doc/r1127/pr1127_task1rpt_20020101.pdf and http://www.arb.ca.gov/planning/sip/sjv_report/addtl_resources.pdf), which emits relatively low levels of CH_4 (17 kg/yr per cow) according to the 2009 CARB GHG inventory. The tradeoff for this practice is that it emits larger amounts of NH_3 than other types of manure management (http://www.epa.gov/ttn/chief/ap42/ch09/draft/draftanimalfeed.pdf). Therefore, if we attribute dry manure management emissions to the SoCAB dairy cow population, and the dry lot emission rate of 2.1 kg CH_4/yr for the remaining heifers, we get an additional 2.7 Gg CH_4/yr from dairy operation manure management in the SoCAB. This results in a total of 31.6 Gg CH_4/yr from enteric fermentation and manure management for the SoCAB dairy operations. This is the emission from agriculture and forestry that we add back into the population-apportioned CARB CH_4 inventory above (Table 2).

Our estimate of 31.6 Gg CH_4/yr, based on inventory data, is less than half of the 76 Gg CH_4/yr estimated by *Wennberg et al.* [2012]. We attribute this difference in bottom-up inventories to the different assumptions of manure management practices.

Wennberg et al. [2012] scaled total California CH_4 emissions by livestock population, which also assumes the manure management practices from the San Joaquin Valley apply to the L.A. basin. For example, the anaerobic lagoons more commonly used in the San Joaquin Valley emit 325 kg CH_4 per cow per year according to the 2009 CARB GHG inventory, significantly higher than 17 kg CH_4 per cow per year from dry manure management practices typical of the L.A. basin.

Nowak et al. [2012] used P-3 data from CalNex to derive emissions of ammonia (NH_3) from dairy farms in the Chino area. From NOAA P-3 measurements, we determine a CH_4 flux from the Chino-area dairies for the same three downwind transects analyzed by *Nowak et al.* [2012]. Using the Chino to SoCAB population apportionment by *Salas et al.* [2008], we expect these same Chino-area dairies to emit approximately 28 Gg CH_4/yr. CH_4 fluxes determined from equation (1) range from 24 ± 12 to 88 ± 44 Gg CH_4/yr, and the average of the three transects is 49 ± 25 Gg CH_4/yr. This value derived from airborne flux determination lies between the 28 Gg CH_4/yr calculated from the inventory assuming dry manure management practices described above, and the estimate by *Wennberg et al.* [2012] of 76 Gg CH_4/yr (less livestock emissions from the SoCAB that are not in the Chino area) assuming mainly wet management practices. We attribute the differences to actual practices in the region, which are likely a mixture of the two manure management approaches. Satellite images of the area show what appear to be several anaerobic lagoons near Chino, California. Our flux determination is therefore consistent with our bottom-up CH_4 emission inventory, with room for a mixture of manure management practices, including some anaerobic lagoons, in the L.A. basin.

4.4. Spatial distribution of methane sources

Townsend-Small et al. [2012] concluded that the CH_4 emissions in the L.A. region had a stable isotope ratio similar to that of fossil-fuel CH_4. This conclusion was based on measurements made at the Mt. Wilson Observatory. A back-trajectory [*White et al.*, 2006; http://www.esrl.noaa.gov/psd/programs/2010/calnex/traj/] from MWO for 5 August 2009, the specific day that *Townsend-Small et al.* [2012] used to determine the excess CH_4 stable isotopic ratio, shows the prevailing winds to MWO were from the southwest, or from downtown L.A. and the coast west of downtown L.A. The trajectory tool also shows winds from the eastern basin on the previous day, which was excluded by *Townsend-Small et al.* [2012] due to lower correlation between the excess CH_4 and $\delta^{13}C$. We conclude that the MWO data interpreted by *Townsend-Small et al.* [2012] were dominated by emissions from the western basin only, and were not influenced by emissions from either the largest landfills (Puente Hills and Olinda Alpha), or from the dairies in the eastern part of the L.A. basin. This spatially-biased sampling is consistent with their conclusion that landfills do not contribute significantly to the total atmospheric CH_4 burden in L.A.

Evidence for the heterogeneous spatial distribution of CH_4 sources in the SoCAB can be seen in the NOAA P-3 data. Figure 4 shows that the correlation of ethane with CH_4 is dependent on the sample location in the L.A. basin. Also shown in Figure 4 is the slope used by *Wennberg et al.* [2012] to represent the ethane/CH_4 ratio (16.5 ± 2.5 ppt ethane/ppb CH_4) in pipeline-quality dry natural gas from the Southern California Gas Company (SoCalGas), the major provider of natural gas to the SoCAB, for 2010.

The chemical data in Figure 4 reflect the known source types shown on the map in Figure 1c: the large CH_4 sources in the eastern L.A. basin, primarily landfills and dairies, are not significant sources of ethane relative to CH_4.

We can reconcile the conclusions of *Townsend-Small et al.* [2012] and *Wennberg et al.* [2012] with the CARB GHG inventory by noting that fossil fuel CH_4 emissions predominate in the western basin, and that landfill and livestock CH_4 emissions predominate in the eastern basin. However, in contrast to the findings of *Wennberg et al.* [2012], we find that natural gas leaks from the SoCalGas and in-home pipelines are not the only possible source of fossil fuel CH_4 to the western basin, as described below.

4.5. Light alkane emissions from local natural gas production

Los Angeles was one of only three out of 28 cities characterized by propane and ethane levels within 10% of one another in the atmosphere [*Baker et al.*, 2008], consistent with an enhanced propane source term in L.A. Figure 5 shows correlations of propane vs. ethane in whole-air samples from various aircraft projects in the Los Angeles region (ITCT 2002, ARCTAS 2008, and CalNex 2010), as well as measurements from the CalNex Pasadena ground site in 2010. Also plotted are lines representing the composition ratios of other possible sources of ethane and propane in Los Angeles.

The L.A. basin is home to oil and gas operations (see Figure 1c); the composition ratios depicting possible emissions from local natural gas (gray lines) and local geologic seeps (salmon lines) in Figure 5 are those reported by *Jeffrey et al.* [1991]. The lower propane content relative to ethane seen in the seeps (*e.g.*, the La Brea tar pits) compared to the local natural gas is attributed to near-surface microorganisms forming shorter-chain alkanes from longer-chain

alkanes during the time the natural gas migrates toward the surface [*Jeffrey et al.*, 1991]. The average propane/ethane ratio for processed gas in SoCalGas pipelines [*Wennberg et al.*, 2012] is plotted as a dashed black line. Pipeline-quality dry natural gas has a low propane/ethane ratio because the natural gas has been processed (*i.e.*, the higher alkanes have been removed from the natural gas) before distribution. The SoCalGas ratio is representative of natural gas piped in from out of state (*e.g.*, from Texas, Wyoming, and Canada); approximately 90% of natural gas used in California is imported (http://www.socalgas.com/regulatory/documents/cgr/2010_CGR.pdf). The on-road emissions are taken from a San Francisco Bay-area tunnel study by *Kirchstetter et al.* [1996], who reported a vehicular emission ratio of 0.13 mol propane/mol ethane roughly similar to those by *Fraser et al.* [1998] (0.27 mol propane/mol ethane) and by *Lough et al.* [2005] (0.06 – 0.18 mol propane/mol ethane). Vehicle engine exhaust typically contains small, decreasing amounts of CH_4, ethane, and propane due to incomplete combustion, as gasoline and diesel fuel do not contain significant amounts of these light alkanes. The on-road emissions, local geologic seeps, and the pipeline-quality dry natural gas from SoCalGas contain 3–5 times more ethane than propane, and therefore cannot alone explain the ambient ratios measured in the L.A. basin. The propane and ethane composition of unprocessed natural gas from local wells, on the other hand, closely matches the SoCAB ambient measurements from three aircraft campaigns, the CalNex ground site measurements, and the *Baker et al.* study [2008]. Propane and ethane were also typically enhanced at the same time, with the exception of one sample with elevated propane near the Long Beach area (Figure 1e).

The data in Figure 5 suggest that local oil and gas wells contribute significantly to the atmospheric propane burden in the SoCAB. However, *Wennberg et al.* [2012] invoked a large

source of propane from fugitive losses from the liquefied petroleum gas (LPG) industry (*i.e.*, propane tanks), in addition to leaks from the pipeline-quality dry natural gas distribution system in the L.A. basin. This would be consistent with past works that have found significant fugitive losses of propane in other cities, such as Mexico City [*Blake and Rowland*, 1995]. We therefore extend our analysis to incorporate ethane, propane, and C_4 (*n*- and *i*-butane) and C_5 (*n*- and *i*-pentane) isomers to better attribute and quantify the sources of light alkanes and CH_4 to the SoCAB atmosphere. Light alkanes are plotted in Figure 6, with lines depicting the composition of natural gas in SoCalGas pipelines [*Wennberg et al.*, 2012] and of on-road emissions [*Kirchstetter et al.*, 1996]. We neglect chemical processing of these long-lived alkanes ($\tau \geq 3$ days at OH = 1×10^6 molecules/cm^3) as we find no detectable difference between daytime and nighttime enhancement ratios relative to CO, similar to the findings of *Borbon et al.* [2013] for *n*-butane and CO at the CalNex Pasadena ground site. Atmospheric enhancement ratios of propane, *n*-butane, and *i*-butane (Figures 6b–d) relative to ethane are consistent with emissions having the composition of local natural gas [*Jeffrey et al.*, 1991]. On-road emissions do not appear to contribute significantly to the CH_4, ethane, and propane in the L.A. atmosphere, and pipeline-quality dry natural gas and/or local geologic seeps do not appear to contribute significantly to the propane and *n*-butane relative to ethane in the L.A. atmosphere. Based on these observations, we conclude that the local natural gas industry contributes a significant fraction to the total atmospheric C_2-C_4 alkane abundances, including propane, in the L.A. basin. We infer CH_4 emissions from the local natural gas industry are non-negligible as well, as discussed below.

4.6. Source Attribution

Here we quantify total emissions of C_2–C_5 alkanes in the L.A. basin by multiplying their observed enhancement ratios to CO by the CARB SoCAB emission inventory for CO. Figure 7 shows C_2–C_5 alkanes plotted versus CO with their respective ODR fits. The slopes from these fits are used in equation (2) along with the projected 2010 CARB CO inventory to calculate annual alkane emissions in the SoCAB. We assume the slopes represent a direct emission with no chemical aging. These emissions are listed in the right-most column of Table 4. Also listed in Table 4 are the estimated contributions from mobile sources in the SoCAB, using C_1–C_5 to CO emission ratios from *Kirchstetter et al.* [1996] (modified as discussed below) and CO emissions from the mobile sources category in the projected 2010 CARB CO inventory, equal to 920 Gg CO/yr, in equation (2).

Wennberg et al. [2012] attributed the inventory CH_4 shortfall [*Wunch et al.*, 2009; *Hsu et al.*, 2010] by ascribing much of the CH_4 and ethane enhancements to fugitive losses of processed pipeline-quality dry natural gas. They further suggest the majority of atmospheric propane is due to LPG industry/propane tank fugitive losses. Here, we consider other possible explanations of the sources of CH_4 and light alkanes in the L.A. basin for the following two reasons. First, the source attribution by *Wennberg et al.* [2012] leaves little room for CH_4 emissions from landfills, wastewater treatment plants, and dairies in the L.A. basin. This solution seems unlikely based on direct emissions flux estimates using the P-3 data downwind of landfills and dairies in the SoCAB, as described above. Second, the attribution by *Wennberg et al.* [2012] would leave a shortfall in both *n*- and *i*-butane emissions that cannot be explained by gasoline evaporation or emissions from mobile sources.

We use a multivariate approach based on a linear combination of the CH_4 and light alkane compositions from known sources in order to attribute and quantify total CH_4 and C_2–C_5 alkane emissions in the South Coast Air Basin.

We include 7 different source types (sectors) with distinct and known CH_4 and C_2–C_5 alkane compositions (Figure 8) in the following analysis: 1) Leaks of processed dry natural gas from pipelines, and/or emissions from local geologic seeps (this approach cannot distinguish between pipeline-quality dry natural gas and local seeps); 2) CH_4-dominated emissions, such as from landfills, wastewater treatment plants, and dairies; 3) Leaks of unprocessed, local natural gas; 4) Leaks of liquefied petroleum gas from propane tanks; 5) On-road combustion emissions from mobile sources; 6) Emissions of CH_4 and C_2–C_5 alkanes in the SoCAB from other source sectors; and 7) Evaporative emissions from gasoline. These are described briefly below.

1. The South Coast Air Basin contains 14.8 million people, and SoCalGas delivers approximately 11 Tg/yr of natural gas to the Los Angeles area. Additionally, the Earth's natural degassing is a known source of CH_4, ethane, and propane to the atmosphere [*Etiope et al.*, 2008; *Etiope and Ciccioli*, 2009], and the L.A. basin contains abundant geologic hydrocarbon reserves [*Jeffrey et al.*, 1991]. We group fugitive losses from processed pipeline-quality dry natural gas with the emissions from local geologic seeps because the C_1–C_4 emissions from these sources are not sufficiently different to be treated separately in our linear combination analysis (illustrated by the similarity in slopes of the dashed black and salmon-colored lines in Figure 6).

Both pipeline-quality dry natural gas and local seep emissions contain similar amounts of CH_4 and ethane relative to one another, and have less C_3–C_5 alkanes relative to ethane than local, unprocessed natural gas. For pipeline-quality dry natural gas, most C_{3+} alkanes are removed during the processing stage, which is typically done close to the source, which for ~90% of the natural gas used in California is in Canada, Wyoming, and/or Texas. For local seeps, most C_{3+} alkanes are either preferentially adsorbed in shallow sediments compared to CH_4, or biodegraded by microbes in the earth's crust during the seepage of local natural gas to the surface [*Jeffrey et al.*, 1991]. We use SoCalGas samples of pipeline-quality natural gas from 2010 [*Wennberg et al.*, 2012] to represent this source, and estimate the uncertainty of the composition at 15%.

2. CH_4-dominant emission sources, which for this analysis include landfills, wastewater treatment plants, and livestock, emit CH_4 but no significant amounts of C_2–C_5 alkanes. This is represented in our analysis as a unit vector containing only CH_4.
3. From 2007–2009, the oil and gas industry in the L.A. basin produced roughly 12–13 billion cubic feet of natural gas per year, mostly associated gas from oil wells (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). We use an average of the samples reported by *Jeffrey et al.* [1991] weighted by 2009 gross natural gas production per field, and estimate the uncertainty of this composition at 25%.
4. Two types of LPG are sold in the Los Angeles area: one is almost completely composed of propane, the other has traces of *n*- and *i*-butane (http://www.arb.ca.gov/research/apr/past/98-338_1.pdf).

We use the ratios reported by *Blake and Rowland* [1995] from direct analysis of LPG in Los Angeles, which is consistent with an average of the two types of LPG sold in L.A, and estimate the uncertainty of the composition at 10%.

5. On-road combustion emissions are modified from the work of *Kirchstetter et al.* [1996] by multiplying emission ratios of alkanes to CO by the 925 Gg CO/yr from on-road sources in the projected 2010 CARB CO inventory. The C_4–C_5 emissions represent unburned fuel and are typically proportional to the fuel composition; the C_1–C_3 emissions typically represent incomplete combustion products. To account for differing fuel compositions since the time of the *Kirchstetter et al.* [1996] study, the *i*- and *n*-butane emissions calculated for mobile sources in the SoCAB (Table 4) have been scaled to the *i*-pentane emissions based on their relative abundance in gasoline [*Gentner et al.*, 2012].
6. There are additional sources of light alkanes in the SoCAB. We use the 2010 CARB speciated inventory for total organic gases (http://arb.ca.gov/ei/speciate/interopt10.htm) and projected 2010 total organic gas emissions (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php) for the SoCAB to estimate emissions of light alkanes not specified in other source sectors. These include emissions from aerosol spray cans and other consumer products, coatings and solvents, adhesives and sealants, and fiberglass and plastics manufacturing. For example, propane, *n*- and *i*-butane are commonly used as propellants in aerosol spray cans, having replaced CFCs in the United States in the 1970s (*e.g.*, CARB estimates 0.6 Gg of aerosol antiperspirant vapors were emitted to the SoCAB in 2010, of which 0.14 Gg, 0.03 Gg, and 0.15 Gg were propane, *n*-, and *i*-butane, respectively).

These emissions are summed and listed in the "CARB other" column in Table 4. Emissions from natural gas leaks, petroleum refining, petroleum marketing (gas stations), landfills and composting, and mobile sources are not included in these totals, because they are accounted for elsewhere in other source sectors. We estimate a 25% uncertainty in the "CARB other" inventory.

7. Emissions ratios from evaporated gasoline were calculated from ten gasoline samples from five Pasadena gas stations in the summer of 2010, weighted by estimated sales of 80% regular and 20% premium [*Gentner et al.*, 2012]. Uncertainties are those reported by *Gentner et al.* [2012].

First, we start with estimated annual C_1–C_5 emissions in the SoCAB (right-most column of Table 4), then subtract modified on-road emissions [*Kirchstetter et al.*, 1996] and projected emissions of C_1–C_5 alkanes from other sources (source sector 6, above). Next, we place the remaining source sector characteristics into a matrix and solve for the fraction each source contributes to the remaining alkane observations for the L.A. basin based on each source's relative abundances of various light alkanes. The matrix has five columns representing the five remaining source sectors, and seven rows containing C_1–C_5 alkanes. We solve the equation [*e.g.*, see §4.2 *Kim et al.*, 2011]

$$\mathbf{A}_{i,j}\ \mathbf{x}_j = \mathbf{b}_i \qquad (3)$$

where $\mathbf{A}_{i,j}$ is a matrix of the C_1–C_5 alkane composition, i, for the source sectors, j, defined above; x_j is the fraction each source contributes to the total observed emissions, and b_i is the total observed emission of alkane i minus the contributions from the mobile and "other" source sectors (Table 4). The columns of the matrix **A** are proportional to the first five columns of

Table 4. We use LAPACK (http://www.netlib.org/lapack/) to solve for the linear least squares solution that minimizes ($\mathbf{Ax} - \mathbf{b}$). Uncertainties in the derived $\mathbf{x}_j$ are estimated by a sensitivity study, where we run the solution 1,000,000 times by randomly varying $\mathbf{A}_{i,j}$ and $\mathbf{b}_i$ according to their estimated uncertainties, then use the standard deviation of the 1,000,000 $\mathbf{x}_j$ determinations to estimate the uncertainty in the source attribution fraction. The source attribution fractions and their uncertainties are multiplied by the total estimated SoCAB emission for each alkane, then are summed with the uncertainties added in quadrature. CH_4 and C_2–C_5 alkane emissions totals, their uncertainties, and the contributions from each source type are given in Table 4. The source attribution solution solves the observed SoCAB alkane emission to within each alkane's emission uncertainty.

Our modeled source attribution differs from the alkane source distribution in the L.A. basin as set forth by *Wennberg et al.* [2012]. From a total calculated source of 410 ± 40 Gg CH_4/yr in the SoCAB, we determine that 47% comes from leaks of processed pipeline-quality dry natural gas and/or from local geologic seeps; 44% of the CH_4 comes from the sum of landfill, wastewater treatment, and dairy emissions; 8% from the leaks of unprocessed natural gas from production in the western L.A. basin; and 1% from mobile sources. The attribution is presented graphically in Figure 8. Figure 8a displays the total SoCAB emissions as a black horizontal line in each panel, with contributions from the different source sectors given below the line by the filled bars. Figure 8b shows the proportion that each source sector contributes to the derived total emissions of each alkane.

Our analysis attributes CH_4 emissions of 192 ± 54 Gg CH_4/yr to leaks of pipeline-quality dry processed natural gas and/or leaks from local geologic seeps, but does not distinguish further between these two different sources. This value is nearly a factor of 5 greater than the population-apportioned 2009 CARB GHG emissions inventory estimate of 40 Gg CH_4/yr lost from natural gas pipelines in the SoCAB. Our estimate of 192 Gg CH_4/yr is less than the maximum emission of 400 ± 150 Gg CH_4/yr estimated by *Wennberg et al.* [2012]. Our estimate would represent approximately 2% of the natural gas delivered to customers in the SoCAB and, including storage and deliveries to customers outside the SoCAB, 1% of the gas flowing into the basin [*Wennberg et al.*, 2012]. These percentages would decrease linearly with any CH_4 emissions attributed to local geologic seeps. *Farrell et al.* [*in press*, 2012] estimate up to 55 Gg CH_4/yr are emitted from the La Brea Tar Pits in western L.A. County alone; if accurate, this would imply pipeline leaks of only 0.7% of the gas flowing into the basin, or a factor of at least two lower than the 2% proposed by *Wennberg et al.* [2012].

Our analysis attributes 182 ± 54 Gg CH_4/yr in the SoCAB to emissions from landfills, wastewater treatment, and dairies. SoCAB landfills account for 164 Gg CH_4/yr in the 2008 CARB GHG inventory, a value supported by our analysis in section 4.2. In section 4.3, we estimated in a bottom-up inventory that SoCAB dairies emitted 31.6 Gg CH_4/yr. *Wennberg et al.* [2012] estimated an emission of 20 Gg CH_4/yr from wastewater treatment. These independent estimates sum to 216 Gg CH_4/yr and are consistent with our source apportionment using NOAA P-3 data.

CH_4 emissions of 31.9 ± 6.5 Gg CH_4/yr are ascribed to leaks of local, unprocessed natural gas, and would represent 17% of the local production in 2009, the latest year for which data are available (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). This number assumes a CH_4 composition of 72.5% by volume for natural gas produced in the South Coast Air Basin, which is calculated as an average from the samples reported by *Jeffrey et al.* [1991] weighted by 2009 production. Our derived value of 17%, although a surprisingly high amount of local production, is consistent with a nascent bottom-up estimate under way at CARB. A new bottom-up inventory survey, conducted by CARB for the calendar year 2007 but not yet incorporated into the official GHG inventory, indicates that 109 Gg CH_4/yr, since revised to 95.5 Gg CH_4/yr [*S. Detwiler,* personal communication, October 2012], were emitted throughout California by the oil and gas industry via combustion, venting, and fugitive losses (table 3-1, http://www.arb.ca.gov/cc/oil-gas/finalreport.pdf). This updated value is a factor of 2.5 larger than the current CARB GHG inventory tabulation of 38 Gg CH_4/yr from oil and gas extraction for 2007 in California. CH_4-specific emissions for the South Coast Air Management District in the new CARB survey report show 24.6 Gg CH_4/yr were emitted in the SoCAB [S. Detwiler, personal communication, October 2012]. According to the survey, emissions in the SoCAB accounted for 26% of the revised statewide total oil and gas operations CH_4 emission in 2007, despite accounting for only 4.4% of statewide natural gas production in the basin that year (http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx). Thus, the survey responses suggest a CH_4 leak rate of 12% of local production in the L.A. basin.

Thus, our estimate of CH_4 emissions from local natural gas for 2010 based on P-3 data from CalNex is within a factor of 1.5 of the CARB bottom-up inventory currently in development based on the 2007 survey. According to the survey, other oil and gas producing regions in California show smaller CH_4 loss rates than that from the SoCAB. For instance, statewide losses of CH_4 represent approximately 2.1% of statewide production, and CH_4 losses from the San Joaquin Air Quality District represent approximately 1.4% of production (from Oil and Gas Districts 4 and 5). This indicates that losses from natural gas production are proportionally larger in the L.A. basin than elsewhere in the State of California.

A propane emission of 6.6 ± 2.9 Gg/yr from LPG/propane tanks would represent approximately 1% of sales (http://www.aqmd.gov/ceqa/documents/2012/aqmd/finalEA/PAR1177/1177_FEA.pdf), which is less than the ~4% calculated by *Wennberg et al.* [2012], and closer to the 0.6% estimated from the document cited.

Finally, our analysis suggests a resolution to the discrepancies noted above between previous top-down assessments and the bottom-up inventory calculations for CH_4 in the SoCAB [*e.g.*, *Wunch et al.*, 2009; *Hsu et al.*, 2010; *Townsend-Small et al.*, 2012; *Wennberg et al.*, 2012]. We conclude the most probable source for the excess atmospheric CH_4 is likely due to a combination of primarily leaks, not accurately represented in the current CARB GHG inventory, from natural gas pipelines and urban distribution systems and/or from local geologic seeps, and secondarily leaks of unprocessed natural gas from local oil and gas production centered in the western L.A. basin.

This finding is based on the characteristic enhancement ratios of CH_4 and the various C_2–C_5 alkanes consistently observed in the L.A. atmosphere, and is further supported by the spatial information provided by P-3 samples during CalNex. Finally, the updated values for local oil and gas industry emissions in the recent GHG survey commissioned by CARB, when incorporated fully into the official CARB GHG record, will likely help to reduce this long-standing discrepancy between top-down assessments and bottom-up inventories.

5. Conclusions

We use aircraft measurements of CH_4, CO, and CO_2 during the CalNex field campaign to show that emissions of CH_4 to the L.A. basin are greater than can be explained by official state bottom-up inventories apportioned by population, consistent with published work. The ratio of the CARB CO and CO_2 inventories is in better agreement with our measurements of CO/CO_2 in the Los Angeles atmosphere than was the case for the analysis by *Wunch et al.* [2009], which we attribute either to improved CARB inventories, the present use of a basin-wide data set to determine basin-wide emission ratios, or both.

From crosswind plume transects downwind of the two largest landfills in the basin, we determine CH_4 fluxes that are consistent with the 2008 CARB GHG inventory values, which total 164 Gg CH_4/yr emitted from all landfills in the South Coast Air Basin. CH_4 emission fluxes were also determined for Chino-area dairies in the eastern L.A. basin. Flux estimates from these dairies ranged from 24 ± 12 to 87 ± 44 Gg CH_4/yr, and the average flux is consistent with a revised bottom-up inventory originally compiled by *Salas et al.* [2008] and with previous inventory estimates [*Wennberg et al.*, 2012].

Finally, we present a top-down assessment of C_2–C_5 alkane sources in the L.A. basin, then apportion CH_4 and the C_2–C_5 alkanes to specific source sectors in the region. Using this source apportionment approach, we estimate that 32 ± 7 Gg of CH_4/yr, or 8% of the total CH_4 enhancement observed in the SoCAB during CalNex, came from the local oil and gas industry. This number represents approximately 17% of the natural gas produced in the region, within a factor of 1.5 of that calculated from a recent survey that will be used to update the CARB bottom-up inventory. We estimate 182 ± 54 Gg CH_4/yr are emitted by landfills, dairies, and wastewater treatment, which is consistent with bottom-up inventories, and 192 ± 54 Gg CH_4/yr are emitted of processed pipeline-quality dry natural gas and/or from geologic seeps in the region. We further conclude that leaks of processed pipeline-quality dry natural gas and/or local geologic seeps, and unprocessed natural gas from local oil and gas production are the most likely major contributors to the previously noted discrepancy between CH_4 observations and State of California inventory values for the South Coast Air Basin. Our findings suggest that basin-wide mobile studies targeting CH_4 and C_2–C_5 alkane emissions from natural gas pipelines and urban distribution systems, geologic seeps, and local oil and gas industry production sites would be useful to further distinguish the sources of CH_4 in the L.A. basin.

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Table 1. Summary of past studies investigating CH_4 emissions in the L.A. basin.

Study	Time of study	Geographic area	Percentage of California population in geographic area	CH_4 Emission (Gg/yr)	Inventory referenced	Bottom-up CH_4 emission inventory (Gg/yr)
Wunch et al. [2009]	August 2007 – June 2008	SoCAB	43%	400 ± 100	CARB CO 2007	260[b]
				600 ± 100	(CARB CO_2 2006 + EDGAR CO_2 2005)/2	
Hsu et al. [2010]	April 2007 – May 2008	L.A. County ∩ SoCAB	27%	200 ± 10	CARB CO 2007	140
Wennberg et al. [2012]	April 2007 – May 2008	SoCAB	43%	380[a] ± 100	CARB CO 2007	---
	June 2008	SoCAB	43%	470 ± 100	CARB CO 2008	---
	May 2010 – June 2010	SoCAB	43%	440 ± 100	CARB CO 2010	---

[a] *Wennberg et al.* [2012] recalculated the data reported by *Hsu et al.* [2010] to estimate a CH_4 emission from the entire SoCAB.

[b] *Wunch et al.* [2009] apportioned the statewide CARB GHG inventory for CH_4, less agriculture and forestry emissions, by population

Table 2. Inventories used in current analysis

Emission	Inventory	Year	Geographic Area
180 Tg CO_2/yr	CARB GHG[a]	2009	SoCAB[c]
979 Gg CO/yr	CARB[b]	2010	SoCAB[c]
301 Gg CH_4/yr	CARB GHG[a]	2009	SoCAB[c]

[a] 2009 CARB CO_2 and CH_4 emissions (http://www.arb.ca.gov/cc/inventory/data/data.htm)

[b] projected 2010 CARB CO emissions (http://www.arb.ca.gov/app/emsinv/fcemssumcat2009.php)

[c] statewide inventory apportioned by SoCAB population

Table 3. Landfill emission fluxes determined aboard the NOAA P-3 in 2010 from downwind plume transects.

Landfill	Transect Date	Flux, 10^{25} molecules/s	Flux, Gg/yr	2008 CARB GHG inventory,[a] Gg/yr
Olinda Alpha	8 May	1.13	9.5	
	14 May	1.45	12.2	
	16 May	1.74	14.6	
	19 May	1.61	13.5	
	20 June	2.90	24.3	
	average[b]	**1.49 ± 0.35**	**12.5 ± 2.9**	**11.0**
Puente Hills	8 May	4.29	36.0	
	19 May	3.62	30.4	
	20 June	4.48	37.6	
	average[b]	**4.06 ± 1.18**	**34.0 ± 9.9**	**38.8**

[a] data from CARB [L. Hunsaker, personal communication, June 2011]

[b] weighted average, assuming a 50% uncertainty in the individual flux determinations [*Taylor*, 1997]

Table 4. Derived emissions in the South Coast Air Basin (in Gg/yr) for 2010 from each source sector used in linear analysis.

	Pipeline-quality dry NG/ local seeps	CH_4-dominant (landfills, dairies, etc.)	Local NG	LPG/propane	Evaporated gasoline	Mobile sources	CARB other	Summed source totals	Estimated SoCAB total[a]
CH_4	192 ± 54	182 ± 54	32 ± 7	---	---	4.9 ± 1.3	1.2 ± 0.3	411 ± 77	411[b] ± 37
ethane	5.9 ± 1.7	---	4.5 ± 1.0	0.05 ± 0.02	0.0 ± 0.0	0.6 ± 0.1	0.3 ± 0.1	11.4 ± 1.9	11.4[b] ± 1.6
propane	1.5 ± 0.4	---	9.9 ± 2.0	6.6 ± 2.9	0.006 ± 0.001	0.1 ± 0.0	1.6 ± 0.4	19.8 ± 3.6	19.8 ± 2.7
n-butane	0.3 ± 0.1	---	5.9 ± 1.2	0.02 ± 0.01	0.5 ± 0.1	0.3 ± 0.1	1.4 ± 0.4	8.5 ± 1.3	8.3 ± 1.2
i-butane	0.3 ± 0.1	---	2.2 ± 0.5	0.13 ± 0.06	0.08 ± 0.02	0.04 ± 0.01	1.8 ± 0.5	4.6 ± 0.6	5.1 ± 0.7
n-pentane	0.07 ± 0.02	---	2.2 ± 0.5	---	2.6 ± 0.4	1.0 ± 0.1	0.3 ± 0.1	6.6 ± 0.6	6.5 ± 0.9
i-pentane	0.11 ± 0.03	---	2.4 ± 0.5	0.003 ± 0.001	7.6 ± 1.0	3.9 ± 0.5	0.03 ± 0.01	14.1 ± 1.2	14.1 ± 1.8

[a] includes measurement, ODR fit, and inventory uncertainty

[b] *Wennberg et al.* [2012] estimate emissions to the SoCAB of 440 ± 100 Gg CH_4/yr and 12.9 ± 0.9 Gg ethane/yr

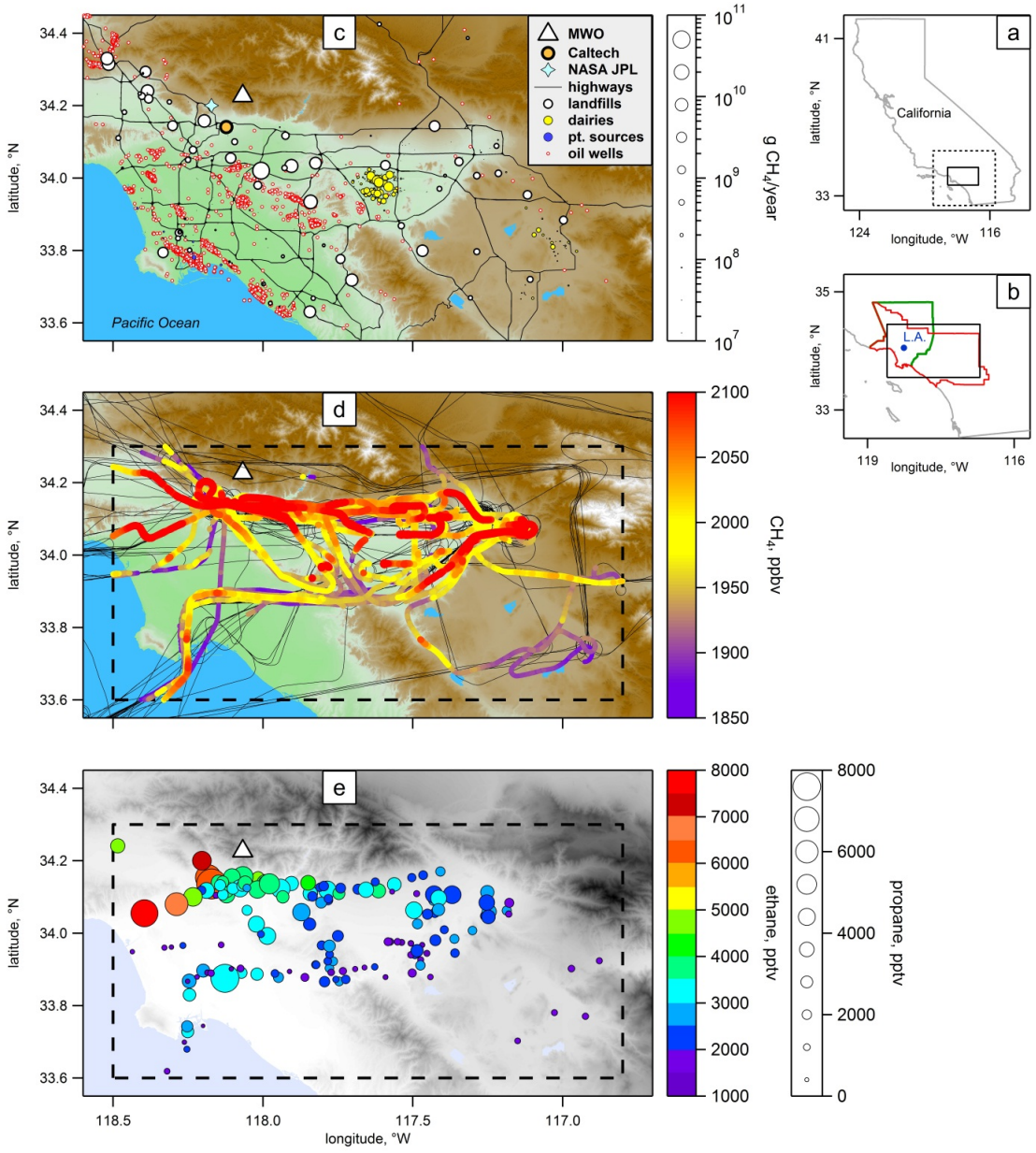

Figure 1. **a)** Map of California. The dashed box shows the inset for panel (b), the solid box shows the extent of the map boundaries for panels (c) – (e). **b)** Map of southern California showing the location of downtown L.A. (blue dot), the Los Angeles County boundary (green), the South Coast Air Basin boundary (red), and the extent of the map boundaries for panels (c) – (e) (black box). **c)** Map of the L.A. region showing known sources of CH_4 in the L.A. basin. The white triangle shows the location of the Mt. Wilson Observatory, where ground-based measurements were made by *Hsu et al.* [2010] and in this study. The light blue star shows the location of the Jet Propulsion Laboratory, where *Wunch et al.* [2009] made their measurements. The CalNex Pasadena ground site was located on the California Institute of Technology (Caltech) campus, located at the orange filled circle. Landfills (white circles) and CH_4 point sources (filled blue circles; negligibly small) are sized by emissions in the 2008 CARB greenhouse gas inventory. Dairies (filled yellow circles) are sized by the estimated emissions from the number of cows from *Salas et al.* [2008] multiplied by the 2009 CARB GHG inventory annual CH_4 emission per cow from enteric fermentation. **d)** Same map of the Los Angeles region as in (c), with flight tracks from 16 daytime flights of the NOAA P-3 (thin black lines). CH_4 measurements from the daytime boundary layer are color-coded atop these tracks according to the legend to the right. **e)** Locations of whole air samples in the L.A. basin, colored by ethane mixing ratio and sized by propane mixing ratio as indicated in the legends to the right.

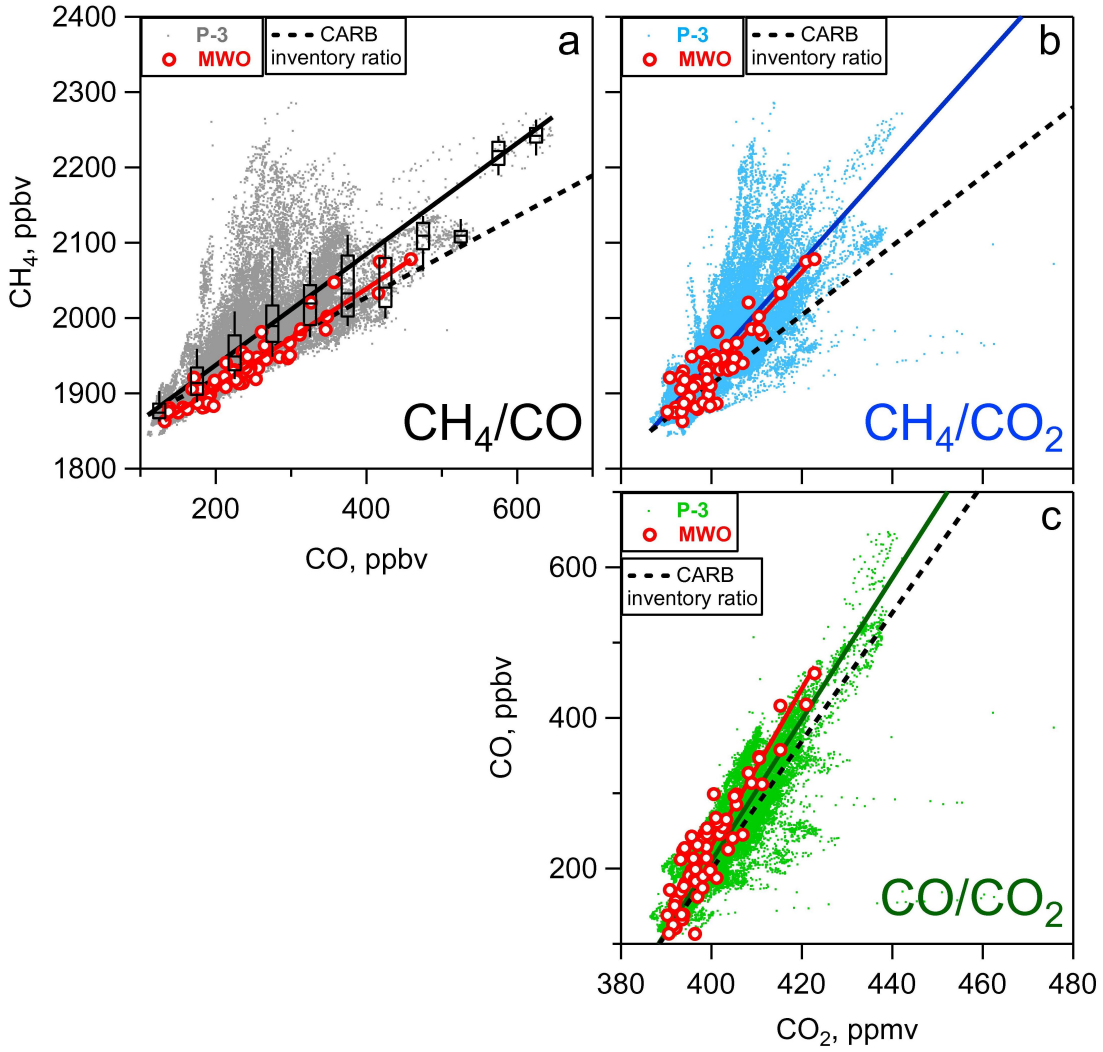

Figure 2. Scatter plots of CH_4, CO_2, and CO from all 1-second data points along flight track highlighted in Figure 1. Dots are from the NOAA P-3, while red circles are from NOAA GMD flask samples taken at the Mt. Wilson Observatory during CalNex. Weighted ODRs (solid lines) result in slopes of **(a)** 0.74 ± 0.04 and 0.68 ± 0.04 ppb CH_4/ppb CO; **(b)** 6.70 ± 0.01 and 6.60 ± 0.04 ppb CH_4/ppm CO_2; and **(c)** 9.4 ± 0.5 and 10.4 ± 0.5 ppb CO/ppm CO_2 from the NOAA P-3 and Mt. Wilson Observatory, respectively. The black dotted lines represent molar ratios of the CARB inventories listed in Table 2: CH_4:CO = 0.54, CH_4:CO_2 = 4.64 × 10^{-3}, and CO:CO_2 = 8.5 × 10^{-3}, where the background values used are the same as those determined from the fitted slopes. Also plotted in Figure 2a are boxes (25^{th}–75^{th} percentiles), whiskers (10^{th}–90^{th} percentiles), and the median (horizontal line) for distributions of CH_4 data calculated for 50 ppbv-wide bins from the NOAA P-3 CO data.

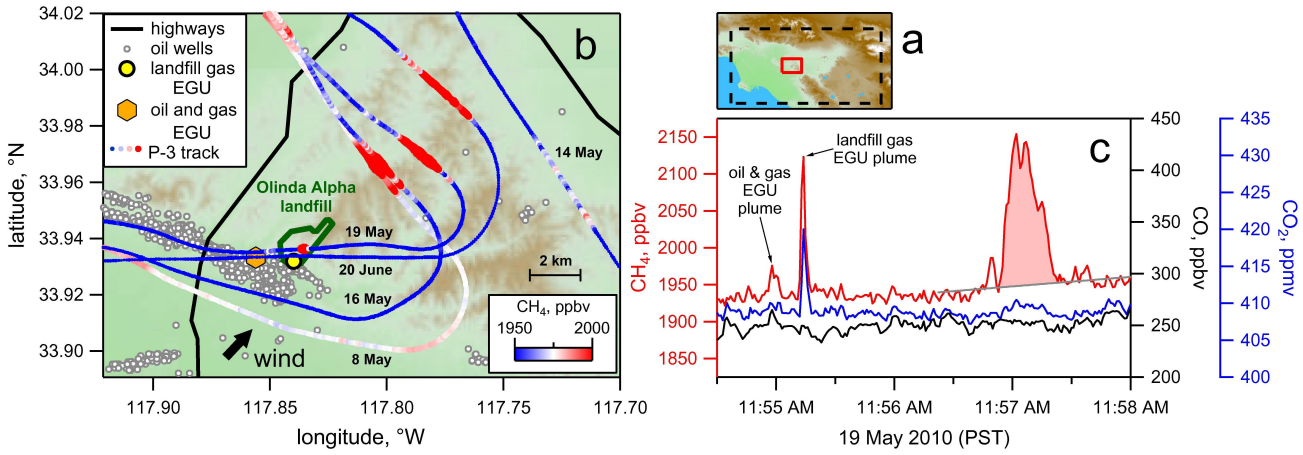

Figure 3. **a)** The map from Figure 1c–e shows the inset for part (b) in red. **b)** Five downwind transects, sized and colored by CH_4 mixing ratio, showing enhancements in CH_4 downwind of the Olinda Alpha landfill (green outline). Winds were from the southwest, except on 14 May, when they were from the west-southwest. **c)** Example of integration of the CH_4 plume from the 19 May flight. The filled pink area is integrated above the surrounding background (gray line). The upwind transect on this day passed downwind of two power plant (EGU) plumes.

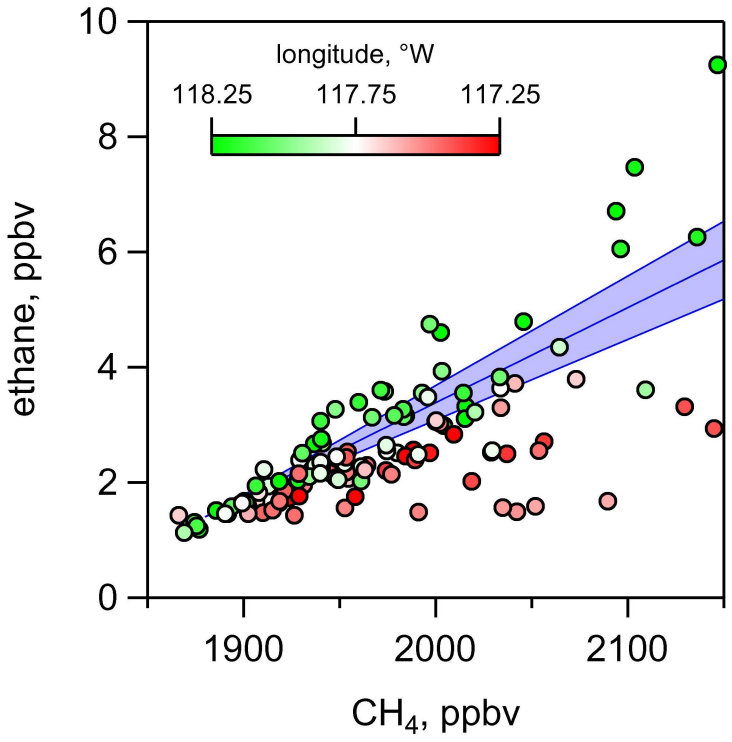

Figure 4. Scatter plot of ethane vs. CH_4 from the NOAA P-3 data in the L.A. basin. Data points are colored by longitude to show the different distributions of ethane to CH_4 in the eastern (red) and western (green) parts of the basin. The blue line represents the slope of 1.65 ± 0.25 % used by *Wennberg et al.* [2012] to represent the estimated ethane/CH_4 ratio of pipeline-quality dry natural gas from the Southern California Gas Company's pipelines.

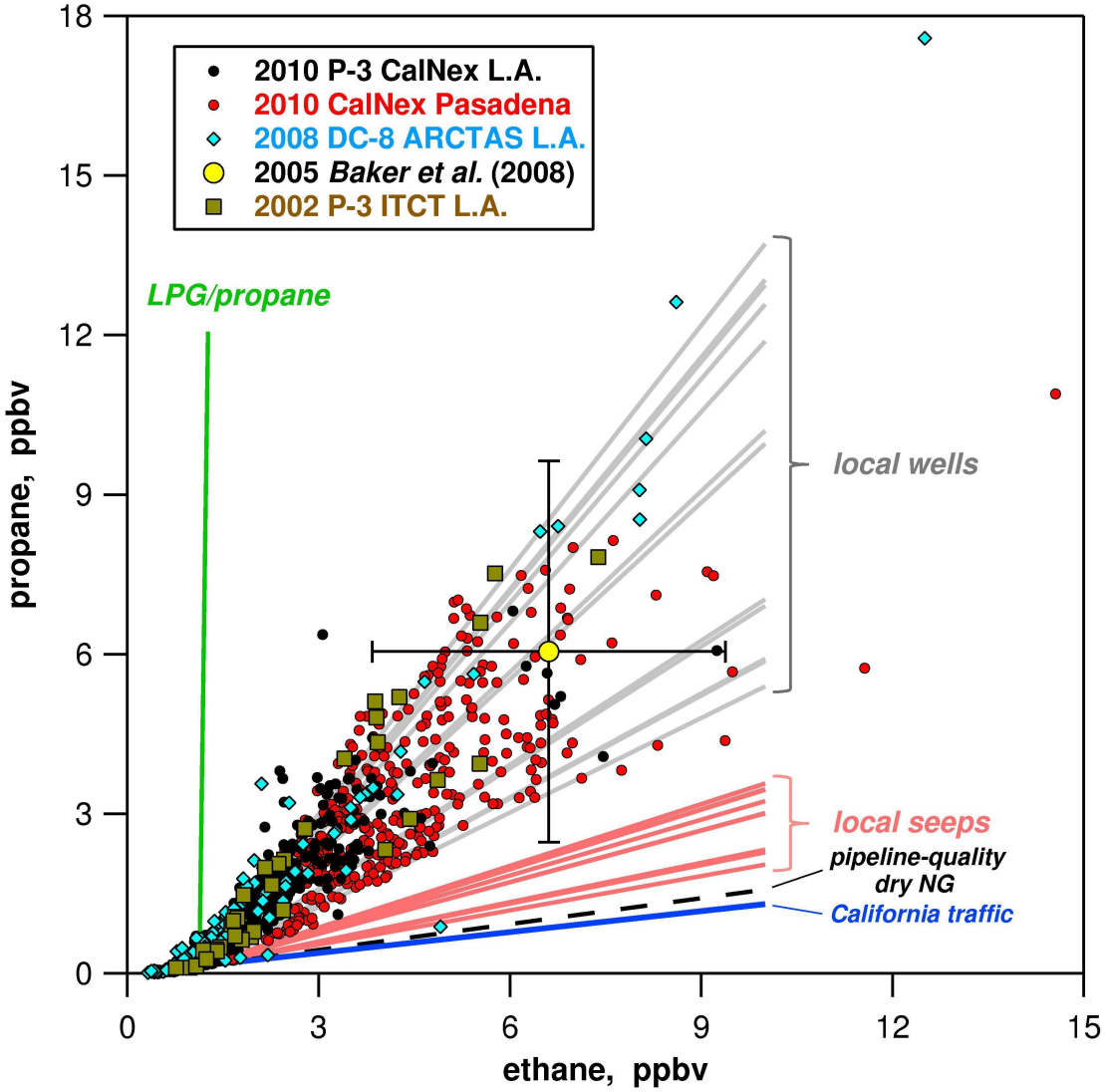

Figure 5. Correlation plot of propane vs. ethane from four Los Angeles datasets. Also plotted are composition ratios of local wells (gray lines) and local seeps (salmon lines) reported by *Jeffrey et al.* [1991], the composition ratio of pipeline-quality dry natural gas (black dashed line), the propane/ethane emission ratio from a San Francisco Bay-area tunnel study reported by *Kirchstetter et al.* [1996], and the average composition ratio of liquefied petroleum gas (LPG), or propane (green line).

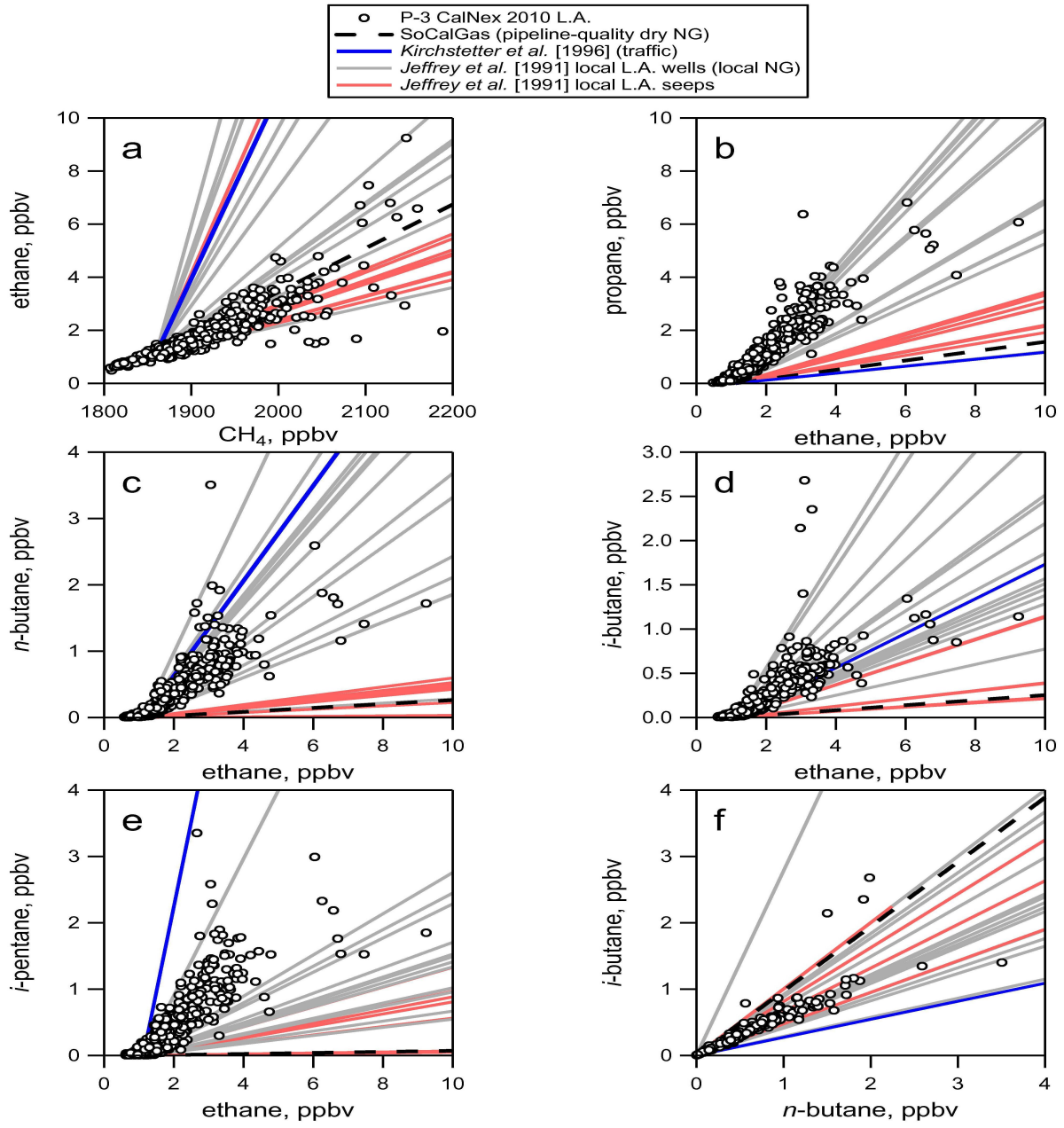

Figure 6. Plots of CH_4 and C_2–C_5 alkanes from the NOAA P-3 CalNex data set, selected for the SoCAB (black circles). Nighttime and high-altitude data are included. Also included for reference are the emission ratios of mobile sources from *Kirchstetter et al.* [1996] (blue line), composition ratios measured by *Jeffrey et al.* [1991] for local natural gas (gray lines) and local geologic seeps (salmon lines), and composition ratios from pipeline-quality dry natural gas (NG) delivered by SoCalGas (dashed black line). These ratios were plotted from daytime background levels.

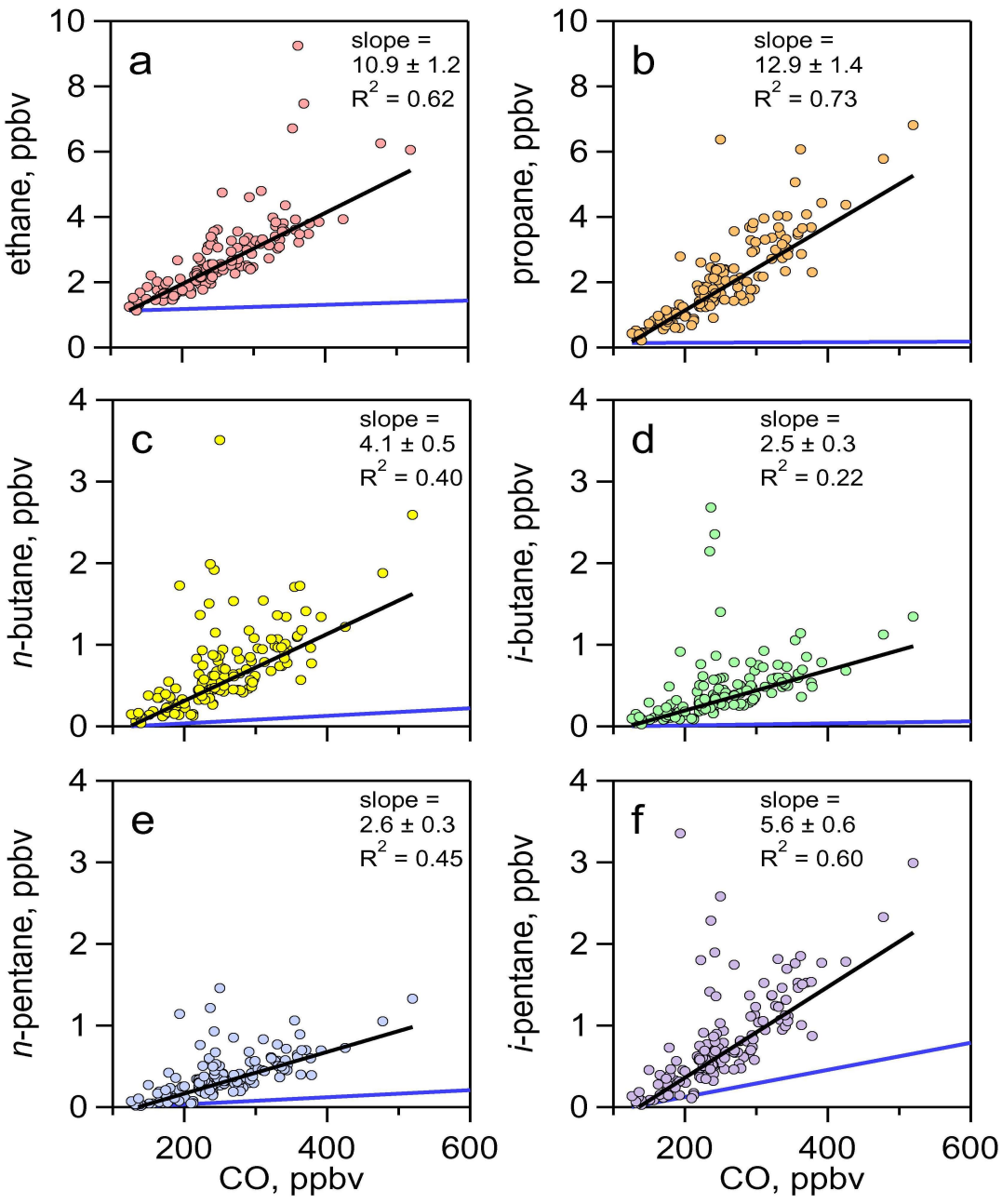

Figure 7. a–f) Daytime measurements of alkanes vs. CO from the NOAA P-3 in the L.A. basin during CalNex are plotted as filled circles. For comparison, the alkane/CO emission ratios from a San Francisco Bay-area tunnel study [*Kirchstetter et al.*, 1996] are plotted as a solid blue line, which extends to the edge of the right axis. The slope from a weighted ODR (given as ppt alkane/ppb CO), total slope uncertainty, and R^2 are given in each panel.

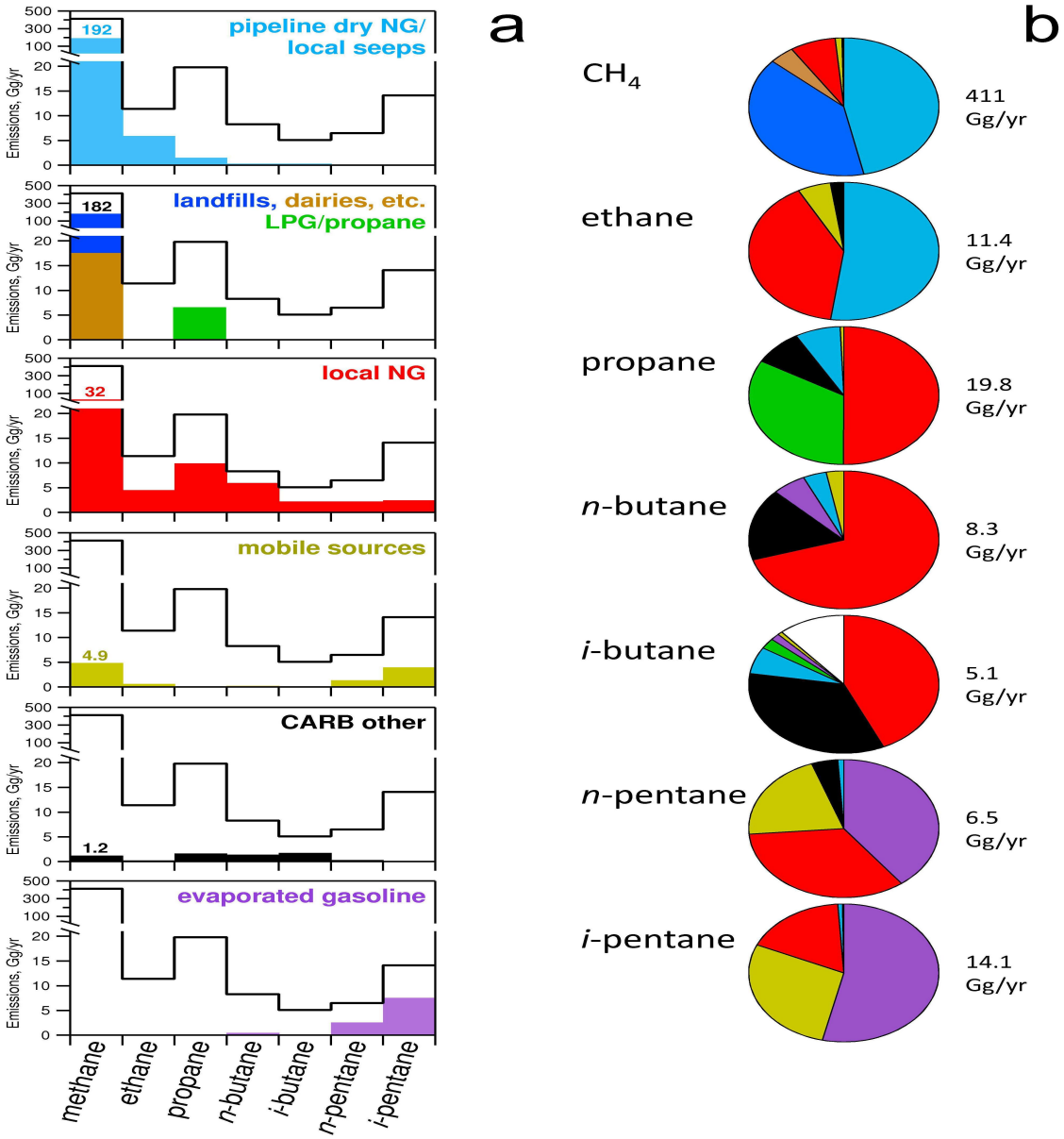

Figure 8. **a)** Results from a linear least squares solution to a combination of six sources and seven trace gas species in the SoCAB. The thick black line represents the estimated total annual emission to the SoCAB for seven hydrocarbons (CH_4 and C_2–C_5). The colored bars represent the fraction of the total contributed by each of the six source sectors used in the linear analysis. CH_4 emissions are written above the bar. **b)** Pie charts for the same data in (a) showing the relative contributions from each source for each of seven alkanes, colored as in part (a). The white region in the *i*-butane pie chart represents the 11% shortfall between our source attribution and our estimated emission to the SoCAB, though it is within the uncertainties of these two values. The total emission of the alkane to the SoCAB is given to the right of each pie chart.

Anthropogenic emissions of methane in the United States

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This study quantitatively estimates the spatial distribution of anthropogenic methane sources in the United States by combining comprehensive atmospheric methane observations, extensive spatial datasets, and a high-resolution atmospheric transport model. Results show that current inventories from the US Environmental Protection Agency (EPA) and the Emissions Database for Global Atmospheric Research underestimate methane emissions nationally by a factor of ∼1.5 and ∼1.7, respectively. Our study indicates that emissions due to ruminants and manure are up to twice the magnitude of existing inventories. In addition, the discrepancy in methane source estimates is particularly pronounced in the south-central United States, where we find total emissions are ∼2.7 times greater than in most inventories and account for 24 ± 3% of national emissions. The spatial patterns of our emission fluxes and observed methane–propane correlations indicate that fossil fuel extraction and refining are major contributors (45 ± 13%) in the south-central United States. This result suggests that regional methane emissions due to fossil fuel extraction and processing could be 4.9 ± 2.6 times larger than in EDGAR, the most comprehensive global methane inventory. These results cast doubt on the US EPA's recent decision to downscale its estimate of national natural gas emissions by 25–30%. Overall, we conclude that methane emissions associated with both the animal husbandry and fossil fuel industries have larger greenhouse gas impacts than indicated by existing inventories.

climate change policy | geostatistical inverse modeling

Methane (CH_4) is the second most important anthropogenic greenhouse gas, with approximately one third the total radiative forcing of carbon dioxide (1). CH_4 also enhances the formation of surface ozone in populated areas, and thus higher global concentrations of CH_4 may significantly increase ground-level ozone in the Northern Hemisphere (2). Furthermore, methane affects the ability of the atmosphere to oxidize other pollutants and plays a role in water formation within the stratosphere (3).

Atmospheric concentrations of CH_4 [∼1,800 parts per billion (ppb)] are currently much higher than preindustrial levels (∼680–715 ppb) (1, 4). The global atmospheric burden started to rise rapidly in the 18th century and paused in the 1990s. Methane levels began to increase again more recently, potentially from a combination of increased anthropogenic and/or tropical wetland emissions (5–7). Debate continues, however, over the causes behind these recent trends (7, 8).

Anthropogenic emissions account for 50–65% of the global CH_4 budget of ∼395–427 teragrams of carbon per year $(TgC{\cdot}y)^{-1}$ (526–569 Tg CH_4) (7, 9). The US Environmental Protection Agency (EPA) estimates the principal anthropogenic sources in the United States to be (in order of importance) (*i*) livestock (enteric fermentation and manure management), (*ii*) natural gas production and distribution, (*iii*) landfills, and (*iv*) coal mining (10). EPA assesses human-associated emissions in the United States in 2008 at 22.1 TgC, roughly 5% of global emissions (10).

The amount of anthropogenic CH_4 emissions in the US and attributions by sector and region are controversial (Fig. 1). Bottom-up inventories from US EPA and the Emissions Database for Global Atmospheric Research (EDGAR) give totals ranging from 19.6 to 30 $TgC{\cdot}y^{-1}$ (10, 11). The most recent EPA and EDGAR inventories report lower US anthropogenic emissions compared with previous versions (decreased by 10% and 35%, respectively) (10, 12); this change primarily reflects lower, revised emissions estimates from natural gas and coal production Fig. S1. However, recent analysis of CH_4 data from aircraft estimates a higher budget of 32.4 ± 4.5 $TgC{\cdot}y^{-1}$ for 2004 (13). Furthermore, atmospheric observations indicate higher emissions in natural gas production areas (14–16); a steady 20-y increase in the number of US wells and newly-adopted horizontal drilling techniques may have further increased emissions in these regions (17, 18).

These disparities among bottom-up and top-down studies suggest much greater uncertainty in emissions than typically reported. For example, EPA cites an uncertainty of only ±13% for the for United States (10). Independent assessments of bottom-up inventories give error ranges of 50–100% (19, 20), and

Significance

Successful regulation of greenhouse gas emissions requires knowledge of current methane emission sources. Existing state regulations in California and Massachusetts require ∼15% greenhouse gas emissions reductions from current levels by 2020. However, government estimates for total US methane emissions may be biased by 50%, and estimates of individual source sectors are even more uncertain. This study uses atmospheric methane observations to reduce this level of uncertainty. We find greenhouse gas emissions from agriculture and fossil fuel extraction and processing (i.e., oil and/or natural gas) are likely a factor of two or greater than cited in existing studies. Effective national and state greenhouse gas reduction strategies may be difficult to develop without appropriate estimates of methane emissions from these source sectors.

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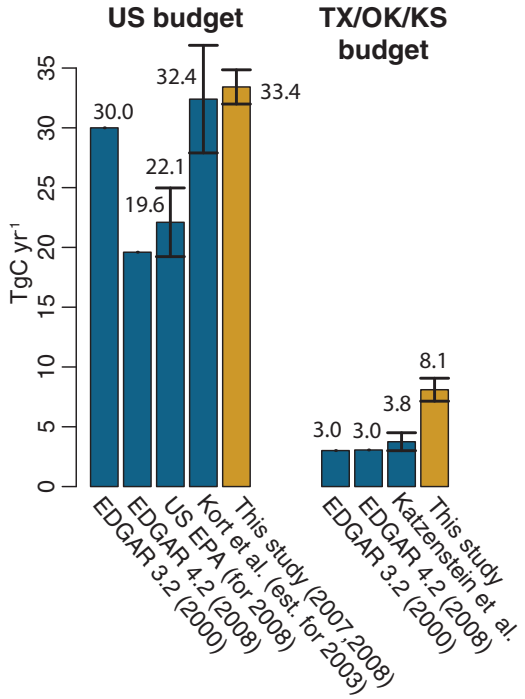

Fig. 1. US anthropogenic methane budgets from this study, from previous top-down estimates, and from existing emissions inventories. The south-central United States includes Texas, Oklahoma, and Kansas. US EPA estimates only national, not regional, emissions budgets. Furthermore, national budget estimates from EDGAR, EPA, and Kort et al. (13) include Alaska and Hawaii whereas this study does not.

values from Kort et al. are 47 ± 20% higher than EPA (13). Assessments of CH_4 sources to inform policy (e.g., regulating emissions or managing energy resources) require more accurate, verified estimates for the United States.

This study estimates anthropogenic CH_4 emissions over the United States for 2007 and 2008 using comprehensive CH_4 observations at the surface, on telecommunications towers, and from aircraft, combined with an atmospheric transport model and a geostatistical inverse modeling (GIM) framework. We use auxiliary spatial data (e.g., on population density and economic activity) and leverage concurrent measurements of alkanes to help attribute emissions to specific economic sectors. The work provides spatially resolved CH_4 emissions estimates and associated uncertainties, as well as information by source sector, both previously unavailable.

Model and Observation Framework

We use the Stochastic Time-Inverted Lagrangian Transport model (STILT) to calculate the transport of CH_4 from emission points at the ground to measurement locations in the atmosphere (21). STILT follows an ensemble of particles backward in time, starting from each observation site, using wind fields and turbulence modeled by the Weather Research and Forecasting (WRF) model (22). STILT derives an influence function ("footprint," units: ppb CH_4 per unit emission flux) linking upwind emissions to each measurement. Inputs of CH_4 from surface sources along the ensemble of back-trajectories are averaged to compute the CH_4 concentration for comparison with each observation.

We use observations for 2007 and 2008 from diverse locations and measurement platforms. The principal observations derive from daily flask samples on tall towers (4,984 total observations) and vertical profiles from aircraft (7,710 observations). Tower-based observations are collected as part of the National Oceanic and Atmospheric (NOAA)/Department of Energy (DOE) cooperative air sampling network, and aircraft-based data are obtained from regular NOAA flights (23), regular DOE flights (24), and from the Stratosphere-Troposphere Analyses of Regional Transport 2008 (START08) aircraft campaign (25); all data are publicly available from NOAA and DOE. These observations are displayed in Fig. 2 and discussed further in the *SI Text* (e.g., Fig. S2). We use a GIM framework (26, 27) to analyze the footprints for each of the 12,694 observations, and these footprints vary by site and with wind conditions. In aggregate, the footprints provide spatially resolved coverage of most of the continental United States, except the southeast coastal region (Fig. S3).

The GIM framework, using footprints and concentration measurements, optimizes CH_4 sources separately for each month of 2007 and 2008 on a 1° × 1° latitude–longitude grid for the United States. The contributions of fluxes from natural wetlands are modeled first and subtracted from the observed CH_4 (2.0 $TgC{\cdot}y^{-1}$ for the continental United States); these fluxes are much smaller than anthropogenic sources in the United States and thus would be difficult to independently constrain from atmospheric data (*SI Text*).

The GIM framework represents the flux distribution for each month using a deterministic spatial model plus a stochastic spatially correlated residual, both estimated from the atmospheric observations. The deterministic component is given by a weighted linear combination of spatial activity data from the EDGAR 4.2 inventory; these datasets include any economic or demographic data that may predict the distribution of CH_4 emissions (e.g., gas production, human and ruminant population densities, etc.). Both the selection of the activity datasets to be retained in the model and the associated weights (emission factors) are optimized to best match observed CH_4 concentrations. Initially, seven activity datasets are included from EDGAR 4.2, (*i*) population, (*ii*) electricity production from power plants, (*iii*) ruminant population count, (*iv*) oil and conventional gas production, (*v*) oil refinery production, (*vi*) rice production, and (*vii*) coal production.

We select the minimum number of datasets with the greatest predictive ability using the Bayesian Information Criterion (BIC) (*SI Text*) (28). BIC numerically scores all combinations of available datasets based on how well they improve goodness of fit and applies a penalty that increases with the number of datasets retained.

The stochastic component represents sources that do not fit the spatial patterns of the activity data (Fig. S4). GIM uses

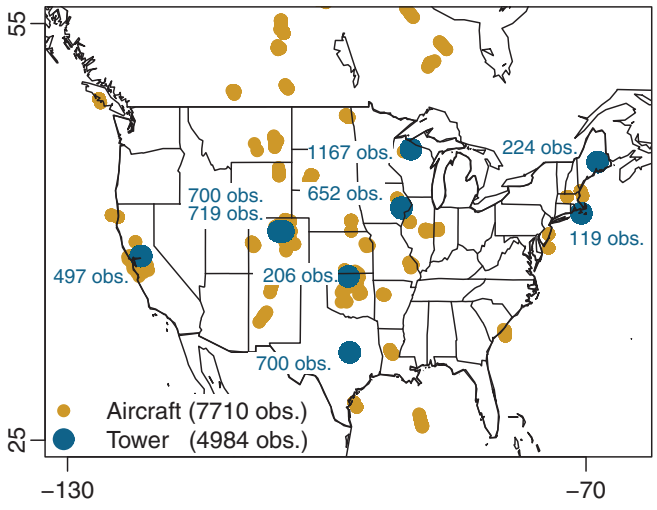

Fig. 2. CH_4 concentration measurements from 2007 and 2008 and the number of observations associated with each measurement type. Blue text lists the number of observations associated with each stationary tower measurement site.

a covariance function to describe the spatial and temporal correlation of the stochastic component and optimizes its spatial and temporal distribution simultaneously with the optimization of the activity datasets in the deterministic component (*SI Text*, Fig. S5) (26–28). Because of the stochastic component, the final emissions estimate can have a different spatial and temporal distribution from any combination of the activity data.

If the observation network is sensitive to a broad array of different source sectors and/or if the spatial activity maps are effective at explaining those sources, many activity datasets will be included in the deterministic model. If the deterministic model explains the observations well, the magnitude of CH_4 emissions in the stochastic component will be small, the assignment to specific sectors will be unambiguous, and uncertainties in the emissions estimates will be small. This result is not the case here, as discussed below (see *Results*).

A number of previous studies used top-down methods to constrain anthropogenic CH_4 sources from global (29–33) to regional (13–15, 34–38) scales over North America. Most regional studies adopted one of three approaches: use a simple box model to estimate an overall CH_4 budget (14), estimate a budget using the relative ratios of different gases (15, 37–39), or estimate scaling factors for inventories by region or source type (13, 34–36). The first two methods do not usually give explicit information about geographic distribution. The last approach provides information about the geographic distribution of sources, but results hinge on the spatial accuracy of the underlying regional or sectoral emissions inventories (40).

Here, we are able to provide more insight into the spatial distribution of emissions; like the scaling factor method above, we leverage spatial information about source sectors from an existing inventory, but in addition we estimate the distribution of emissions where the inventory is deficient. We further bolster attribution of regional emissions from the energy industry using the observed correlation of CH_4 and propane, a gas not produced by biogenic processes like livestock and landfills.

Results

Spatial Distribution of CH_4 Emissions. Fig. 3 displays the result of the 2-y mean of the monthly CH_4 inversions and differences from the EDGAR 4.2 inventory. We find emissions for the United States that are a factor of 1.7 larger than the EDGAR inventory. The optimized emissions estimated by this study bring the model closer in line with the observations (Fig. 4, Figs. S6 and S7). Posterior emissions fit the CH_4 observations [$R^2 = 0.64$, root mean square error (RMSE) = 31 ppb] much better than EDGAR v4.2 ($R^2 = 0.23$, RMSE = 49 ppb). Evidently, the spatial distribution of EDGAR sources is inconsistent with emissions patterns implied by the CH_4 measurements and associated footprints.

Several diagnostic measures preclude the possibility of major systematic errors in WRF–STILT. First, excellent agreement between the model and measured vertical profiles from aircraft implies little bias in modeled vertical air mixing (e.g., boundary-layer heights) (Fig. 4). Second, the monthly posterior emissions estimated by the inversion lack statistically significant seasonality (Fig. S8). This result implies that seasonally varying weather patterns do not produce detectable biases in WRF–STILT. *SI Text* discusses possible model errors and biases in greater detail.

CH_4 observations are sparse over parts of the southern and central East Coast and in the Pacific Northwest. Emissions estimates for these regions therefore rely more strongly on the deterministic component of the flux model, with weights constrained primarily by observations elsewhere. Therefore, emissions in these areas, including from coal mining, are poorly constrained (*SI Text*).

Contribution of Different Source Sectors. Only two spatial activity datasets from EDGAR 4.2 are selected through the BIC as meaningful predictors of CH_4 observations over the United States: population densities of humans and of ruminants (Table S1). Some sectors are eliminated by the BIC because emissions are situated far from observation sites (e.g., coal mining in West Virginia or Pennsylvania), making available CH_4 data insensitive to these predictors. Other sectors may strongly affect observed concentrations but are not selected, indicating that the spatial datasets from EDGAR are poor predictors for the distribution of observed concentrations (e.g., oil and natural gas extraction and oil refining). Sources from these sectors appear in the stochastic component of the GIM (*SI Text*).

The results imply that existing inventories underestimate emissions from two key sectors: ruminants and fossil fuel extraction and/or processing, discussed in the remainder of this section.

We use the optimized ruminant activity dataset to estimate the magnitude of emissions with spatial patterns similar to animal husbandry and manure. Our corresponding US budget of 12.7 ± 5.0 $TgC \cdot y^{-1}$ is nearly twice that of EDGAR and EPA (6.7 and 7.0, respectively). The total posterior emissions estimate over the northern plains, a region with high ruminant density but little fossil fuel extraction, further supports the ruminant estimate (Nebraska, Iowa, Wisconsin, Minnesota, and South Dakota). Our total budget for this region of 3.4 ± 0.7 compares with 1.5 $TgC \cdot y^{-1}$ in EDGAR. Ruminants and agriculture may also be

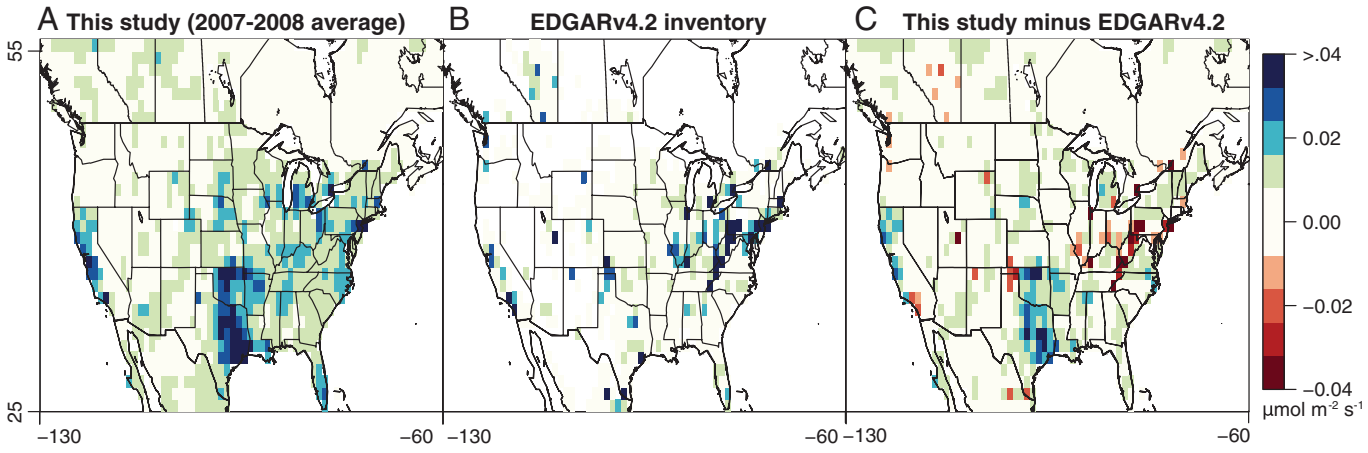

Fig. 3. The 2-y averaged CH_4 emissions estimated in this study (*A*) compared against the commonly used EDGAR 4.2 inventory (*B* and *C*). Emissions estimated in this study are greater than in EDGAR 4.2, especially near Texas and California.

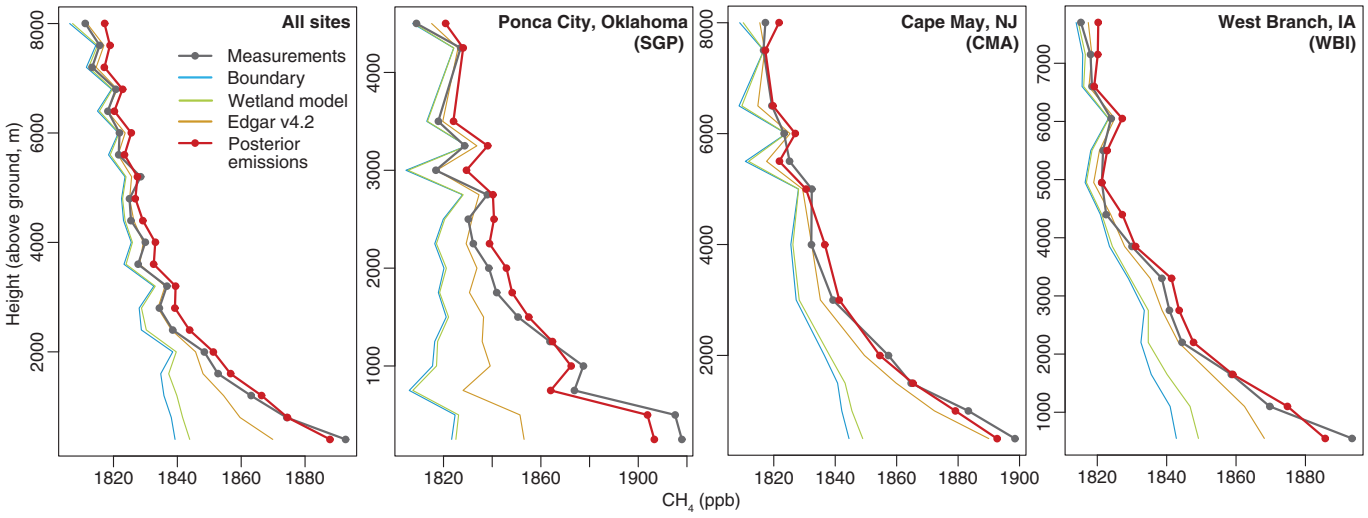

Fig. 4. A model–measurement comparison at several regular NOAA/DOE aircraft monitoring sites (averaged over 2007–2008). Plots include the measurements; the modeled boundary condition; the summed boundary condition and wetland contribution (from the Kaplan model); and the summed boundary, wetland, and anthropogenic contributions (from EDGAR v4.2 and the posterior emissions estimate).

partially responsible for high emissions over California (41). EDGAR activity datasets are poor over California (42), but several recent studies (34, 36–38, 41) have provided detailed top-down emissions estimates for the state using datasets from state agencies.

Existing inventories also greatly underestimate CH_4 sources from the south-central United States (Fig. 3). We find the total CH_4 source from Texas, Oklahoma, and Kansas to be 8.1 ± 0.96 $TgC{\cdot}y^{-1}$, a factor of 2.7 higher than the EDGAR inventory. These three states alone constitute ∼24 ± 3% of the total US anthropogenic CH_4 budget or 3.7% of net US greenhouse gas emissions [in CO_2 equivalents (10)].

Texas and Oklahoma were among the top five natural gas producing states in the country in 2007 (18), and aircraft observations of alkanes indicate that the natural gas and/or oil industries play a significant role in regional CH_4 emissions. Concentrations of propane (C_3H_8), a tracer of fossil hydrocarbons (43), are strongly correlated with CH_4 at NOAA/DOE aircraft monitoring locations over Texas and Oklahoma ($R^2 = 0.72$) (Fig. 5). Correlations are much weaker at other locations in North America ($R^2 = 0.11$ to 0.64).

We can obtain an approximate CH_4 budget for fossil-fuel extraction in the region by subtracting the optimized contributions associated with ruminants and population from the total emissions. The residual (Fig. S4*C*) represents sources that have spatial patterns not correlated with either human or ruminant density in EDGAR. Our budget sums to 3.7 ± 2.0 $TgC{\cdot}y^{-1}$, a factor of 4.9 ± 2.6 larger than oil and gas emissions in EDGAR v4.2 (0.75 $TgC{\cdot}y^{-1}$) and a factor of 6.7 ± 3.6 greater than EDGAR sources from solid waste facilities (0.55 $TgC{\cdot}y^{-1}$), the two major sources that may not be accounted for in the deterministic component. The population component likely captures a portion of the solid waste sources so this residual methane budget more likely represents natural gas and oil emissions than landfills. *SI Text* discusses in detail the uncertainties in this sector-based emissions estimate. We currently do not have the detailed, accurate, and spatially resolved activity data (fossil fuel extraction and processing, ruminants, solid waste) that would provide more accurate sectorial attribution.

Katzenstein et al. (2003) (14) were the first to report large regional emissions of CH_4 from Texas, Oklahoma, and Kansas; they cover an earlier time period (1999–2002) than this study. They used a box model and 261 near-ground CH_4 measurements taken over 6 d to estimate a total Texas–Oklahoma–Kansas CH_4 budget (from all sectors) of 3.8 ± 0.75 $TgC{\cdot}y^{-1}$. We revise their

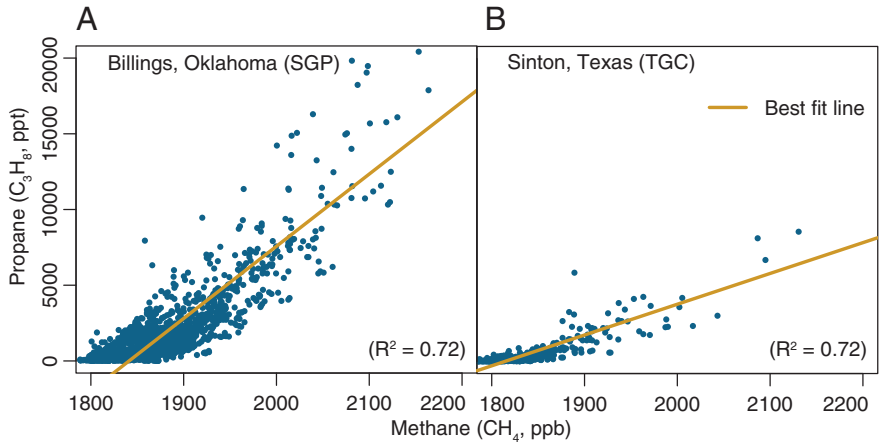

Fig. 5. Correlations between propane and CH_4 at NOAA/DOE aircraft observation sites in Oklahoma (*A*) and Texas (*B*) over 2007–2012. Correlations are higher in these locations than at any other North American sites, indicating large contributions of fossil fuel extraction and processing to CH_4 emitted in this region.

estimate upward by a factor of two based on the inverse model and many more measurements from different platforms over two full years of data. *SI Text* further compares the CH_4 estimate in Katzenstein et al. and in this study.

Discussion and Summary

This study combines comprehensive atmospheric data, diverse datasets from the EDGAR inventory, and an inverse modeling framework to derive spatially resolved CH_4 emissions and information on key source sectors. We estimate a mean annual US anthropogenic CH_4 budget for 2007 and 2008 of 33.4 ± 1.4 $TgC \cdot y^{-1}$ or ∼7–8% of the total global CH_4 source. This estimate is a factor of 1.5 and 1.7 larger than EPA and EDGAR v4.2, respectively. CH_4 emissions from Texas, Oklahoma, and Kansas alone account for 24% of US methane emissions, or 3.7% of the total US greenhouse gas budget.

The results indicate that drilling, processing, and refining activities over the south-central United States have emissions as much as 4.9 ± 2.6 times larger than EDGAR, and livestock operations across the US have emissions approximately twice that of recent inventories. The US EPA recently decreased its CH_4 emission factors for fossil fuel extraction and processing by 25–30% (for 1990–2011) (10), but we find that CH_4 data from across North America instead indicate the need for a larger adjustment of the opposite sign.

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ENERGY AND ENVIRONMENT

Methane Leaks from North American Natural Gas Systems

Methane emissions from U.S. and Canadian natural gas systems appear larger than official estimates.

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Natural gas (NG) is a potential "bridge fuel" during transition to a decarbonized energy system: It emits less carbon dioxide during combustion than other fossil fuels and can be used in many industries. However, because of the high global warming potential of methane (CH_4, the major component of NG), climate benefits from NG use depend on system leakage rates. Some recent estimates of leakage have challenged the benefits of switching from coal to NG, a large near-term greenhouse gas (GHG) reduction opportunity (*1*–*3*). Also, global atmospheric CH_4 concentrations are on the rise, with the causes still poorly understood (*4*).

To improve understanding of leakage rates for policy-makers, investors, and other decision-makers, we review 20 years of technical literature on NG emissions in the United States and Canada [see supplementary materials (SM) for details]. We find (i) measurements at all scales show that official inventories consistently underestimate actual CH_4 emissions, with the NG and oil sectors as important contributors; (ii) many independent experiments suggest that a small number of "superemitters" could be responsible for a large fraction of leakage; (iii) recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical NG system leakage rates; and (iv) assessments using 100-year impact indicators show system-wide leakage is unlikely to be large enough to negate climate benefits of coal-to-NG substitution.

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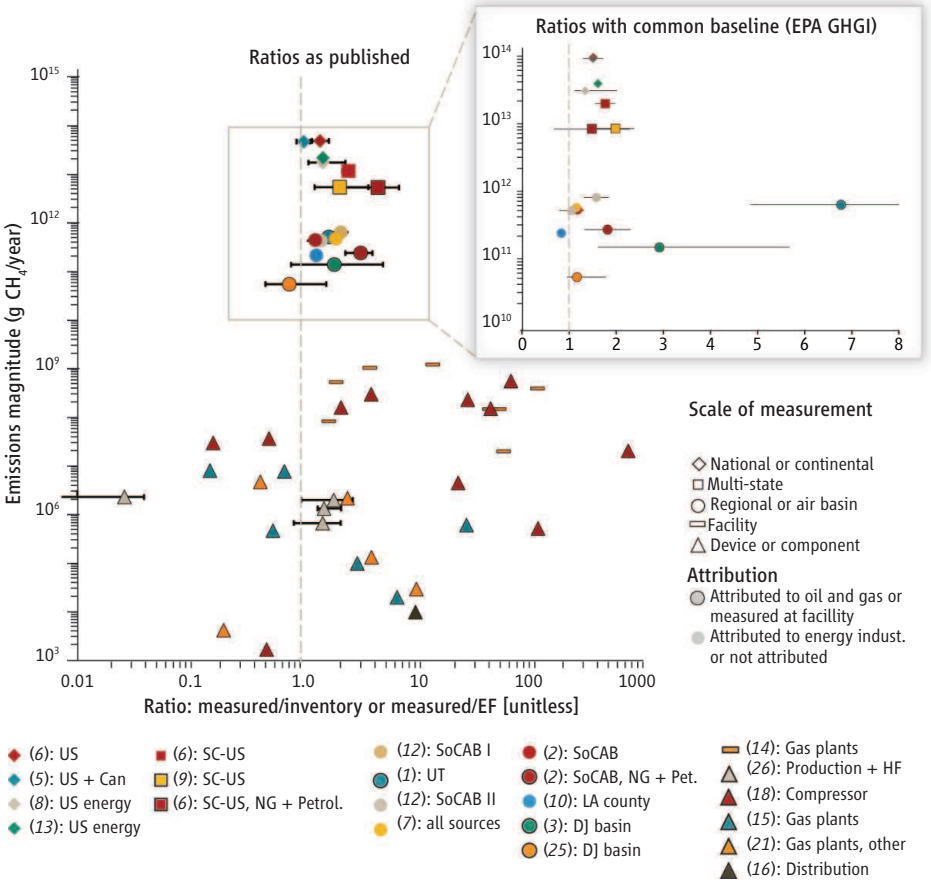
Underestimation—Device to Continent

This study presents a first effort to systematically compare published CH_4 emissions estimates at scales ranging from device-level (>10^3 g/year) to continental-scale atmospheric studies (>10^{13} g/year). Studies known to us that (i) report measurement-based emissions estimates and (ii) compare those estimates with inventories or established emission factors (EFs) are shown in the first chart.

Studies that measure emissions directly from devices or facilities ("bottom-up" studies) typically compare results to emissions factors (EFs; e.g., emissions per device). Large-scale inventories are created by multiplying EFs by activity factors (e.g., number of devices).

Studies that estimate emissions after atmospheric mixing occurs ("atmospheric" studies) typically compare measurements to emissions inventories, such as the U.S. Envi-



Inventories and emissions factors consistently underestimate actual measured CH_4 emissions across scales. Ratios >1 indicate measured emissions are larger than expected from EFs or inventory. Main graph compares results to the EF or inventory estimate chosen by each study author. Inset compares results to regionally scaled common denominator (*17*), scaled to region of study and (in some cases) the sector under examination. Multiple points for each study correspond to different device classes or different cases measured in a single study. Definitions of error bar bounds vary between studies. (US, United States; Can, Canada; SC, South Central; Petrol. and Pet., petroleum; SoCAB, South Coast Air Basin; LA, Los Angeles; DJ, Denver-Julesberg; UT, Utah; HF, hydraulic fracturing). See SM for figure construction details.

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ronmental Protection Agency (EPA) national GHG inventory (GHGI). Atmospheric studies use aircraft (*1*, *5*–*8*), tower (*3*, *6*), and ground (*3*, *7*–*10*) sampling, as well as remote sensing (*7*, *11*, *12*). All such studies observe atmospheric concentrations and must infer fluxes by accounting for atmospheric transport. The various inference methods have strengths and weaknesses (see SM). The greatest challenge for atmospheric studies is attributing observed CH_4 concentrations to multiple potential sources (both anthropogenic and natural).

Results from bottom-up studies (generally $<10^9$ g CH_4/year) and atmospheric CH_4 studies at regional scale and larger (above 10^{10} g CH_4/year) are shown in the first chart. We also include studies that do not focus on NG systems, in order to place NG emissions in context with other CH_4 sources. Across years, scales, and methods, atmospheric studies systematically find larger CH_4 emissions than predicted by inventories. EFs were also found to underestimate bottom-up measured emissions, yet emissions ratios for bottom-up studies are more scattered than those observed in atmospheric studies (*13*–*16*).

Regional and multistate studies focusing on NG-producing (*1*–*3*, *9*) and NG-consuming regions (*2*, *7*, *10*–*12*) find larger excess CH_4 emissions than national-scale studies. This may be due to averaging effects of continental-scale atmospheric processes, to regional atmospheric studies focusing on areas with other air quality problems (*1*, *3*), or simply to methodological variation. Atmospheric measurements are constrained in spatial and temporal density: Regional studies cover 0.5 to 5% of NG production or consumption with dense measurements, although often limited to short-duration sampling "campaigns" (*3*, *7*); national studies cover wide areas with limited sample density (*6*) (table S5).

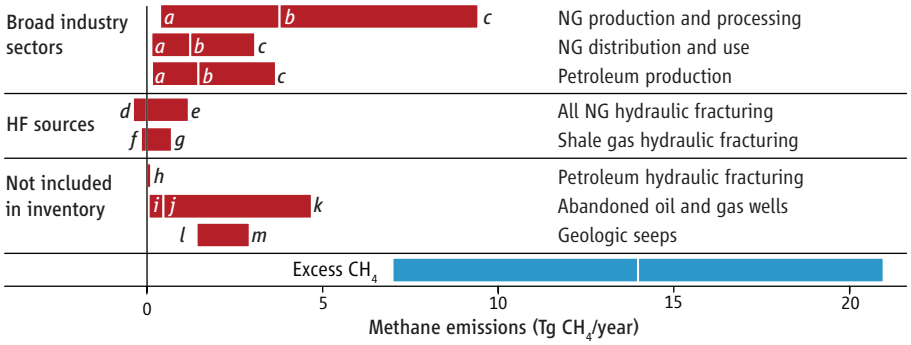
To facilitate comparison, the inset in the first chart normalizes atmospheric studies ($>10^{10}$ g CH_4/year) to baselines computed from the most recent (2011) EPA GHGI estimates for the year and region in which study measurements were made (*17*). After normalization, the largest (e.g., national-scale) atmospheric studies ($>10^{12}$ g CH_4/year) suggest typical measured emissions ~1.5 times those in the GHGI (*5*, *6*, *8*, *9*).

Why might emissions inventories be underpredicting what is observed in the atmosphere? Current inventory methods rely on key assumptions that are not generally satisfied. First, devices sampled are not likely to be representative of current technologies and practices (*18*). Production techniques are being applied at scale (e.g., hydraulic fracturing and horizontal drilling) that were not widely used during sampling in the early 1990s, which underlies EPA EFs (*18*).

Second, measurements for generating EFs are expensive, which limits sample sizes and representativeness. Many EPA EFs have wide confidence intervals (*19*, *20*). And there are reasons to suspect sampling bias in EFs, as sampling has occurred at self-selected cooperating facilities.

Third, if emissions distributions have "heavy tails" (e.g., more high-emissions sources than would be expected in a normal distribution), small sample sizes are likely to underrepresent high-consequence emissions sources. Studies suggest that emissions are dominated by a small fraction of "superemitter" sources at well sites, gas-processing plants, coproduced liquids storage tanks, transmission compressor stations, and distribution systems (see table S6 and fig. S2). For example, one study measured ~75,000 components and found that 58% of emissions came from 0.06% of possible sources (*21*).

Last, activity and device counts used in inventories are contradictory, incomplete, and of unknown representativeness (*17*, *22*). Data should improve with increased reporting requirements enacted by EPA (*23*, *24*).



Potential contributions to total U.S. CH_4 emissions above EPA estimates. EPA estimate in blue, based on central estimate and uncertainty range from large-scale studies from the inset in the first chart. Both NG sources and possible confounding sectors are included. NG production, petroleum production, and NG distribution emissions are based on regional empirical studies (*1*, *2*, *6*), which estimate emissions rates from high-emitting sources but do not estimate prevalence. Scenarios (*a*) to (*c*) correspond to 1, 10, and 25% of gas production or consumption from such high-emitting sources. Ranges (*d*) to (*g*) correspond to estimates for flowback emissions rates during hydraulic fracturing (HF) of all gas wells and shale gas wells, relative to EPA estimates. Ranges (*h*) to (*m*) reflect sources not included in EPA CH_4 inventories but which could be mistaken for NG emissions by chemical or isotopic composition. See SM for details.

Source Attribution in Atmospheric Studies

Does evidence suggest possible sources of excess CH_4 emissions relative to official estimates within the NG sector? A key challenge is attribution of atmospheric observations to sources. Isotopic ratios (*7*, *11*) and prevalence signatures of non-CH_4 hydrocarbons (*3*, *6*–*8*) can be used to attribute emissions to fossil sources rather than biogenic sources. Evidence from regional studies suggests that CH_4 emissions with fossil signatures are larger than expected (*3*, *6*, *7*, *9*, *11*), whereas national-scale evidence suggests a mix of biogenic and fossil sources (*6*). Atmospheric studies that control for biogenic CH_4 sources (*1*, *2*, *7*) are dependent on biogenic source estimation methods that also have high uncertainties (*6*). Natural geologic seeps could confound attribution (see the second chart and SM).

Studies can attribute emissions to liquid petroleum and NG sources rather than coal by sampling in places with little coal-sector activity (*2*, *3*, *6*, *7*, *9*). Attributing leakage to the NG system, as defined by EPA industry sector classifications, is more challenging. Alkane fingerprints may allow attribution to oil-associated NG (*9*), although NG processing changes gas composition, which may complicate efforts to pinpoint leakage sources. Geographic colocation of facilities and sampling, along with geographically isolating wind directions (*2*, *3*, *7*), can allow attribution of emissions to NG subsectors. Without spatial isolation, sector attribution can require assumptions about gas composition that introduce significant uncertainty (*2*, *3*, *25*).

We plotted results of a thought experiment (see the second chart) in which we estimated emissions ranges of selected possible sources within the NG sector, as well as sources that could be mistaken for NG emissions owing to chemical and isotopic signatures. Although such an analysis is speculative given current knowledge, it illustrates ranges of possible source magnitudes.

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We include in the second chart a range of excess CH_4 from all sources (7 to 21 × 10^{12} g or Tg/year) based on normalized national-scale atmospheric studies from the inset in the first chart. This excess is conservatively defined as 1.25 to 1.75 times EPA GHGI estimates. This estimate is derived from national-scale atmospheric studies and includes all sources of CH_4 emissions: It should not be expected that NG sources are responsible for all excess CH_4.

The scenarios in the second chart for NG production and/or processing, distribution, and petroleum system emissions apply observed leakage rates from the literature that are higher than EPA GHGI estimates (*1*, *2*, *7*). The frequency of such high-emitting practices is unknown, so illustrative prevalence scenarios are plotted: 1, 10, or 25% of activity is represented by high-emitters; the remaining facilities emit at EPA GHGI rates. This evidence suggests that high leakage rates found in recent studies (*1*, *2*, *7*) are unlikely to be representative of the entire NG industry; if this were the case, associated emissions would exceed observed total excess atmospheric CH_4 from all sources.

In general, the wide ranges in the second chart suggest a poor understanding of sources of excess CH_4 and point to areas where improved science would reduce uncertainty. However, hydraulic fracturing for NG is unlikely to be a dominant contributor to total emissions (*26*). Also, some sources not included in the GHGI may contribute to measured excess CH_4, e.g., abandoned oil and gas wells and geologic seeps (see SM).

Policy Challenges and Opportunities

Leakage scenarios in the second chart have implications for decision-making and policy. A key tool for environmental decision-making is life-cycle assessment (LCA), which compares impacts associated with varying methods of supplying a useful product (e.g., kWh of electricity). A key challenge in LCA studies is attribution of emissions from systems that produce two products, such as "gas" wells that also produce hydrocarbon liquids, or "oil" wells that also produce NG. This challenge is complicated by incongruence between LCA methodology and EPA sector definitions (see SM).

Recent LCAs have estimated GHG emissions from NG use in power generation and transport (see SM). LCA studies generally agree that replacing coal with NG has climate benefits (*27*). However, LCAs have relied heavily on EPA GHGI results. Updating these assessments with uncertainty ranges from the second chart (see SM) still supports robust climate benefits from NG substitution for coal in the power sector over the typical 100-year assessment period. However, climate benefits from vehicle fuel substitution are uncertain (gasoline, light-duty) or improbable (diesel, heavy-duty) (*28*). These conclusions may undercount benefits of NG, as both EPA GHGI methods and many regionally focused top-down studies attribute CH_4 emissions from coproducing NG systems to the NG sector, rather than to a mixture of oil and NG sources.

How can management and policy help address the leakage problem? Opportunities abound: Many solutions are economically profitable at moderate NG prices, with some technologies already being adopted or to be required in regulation (*23*, *26*) (e.g., reduced emissions completions). Facility studies using existing technology have found leakage detection and repair programs to be profitable (*21*).

The heavy-tailed distribution of observed emissions rates presents an opportunity for large mitigation benefits if scientists and engineers can develop reliable (possibly remote) methods to rapidly identify and fix the small fraction of high-emitting sources.

However, this heterogeneity also creates challenges in formulating statistical distributions for use in inventories. Approaches that assume "typical" emissions rates for this industry are inherently challenged. Inventories can be improved through efforts to better characterize distributions and by incorporating flexibility to adapt to new knowledge.

Improved science would aid in generating cost-effective policy responses. Given the cost of direct measurements, emissions inventories will remain useful for tracking trends, highlighting sources with large potential for reductions, and making policy decisions. However, improved inventory validation is crucial to ensure that supplied information is timely and accurate. Device-level measurements can be performed at facilities of a variety of designs, vintages, and management practices to find low-cost mitigation options. These studies must be paired with additional atmospheric science to close the gap between top-down and bottom-up studies. One such large study is under way (*29*), but more work is required.

If natural gas is to be a "bridge" to a more sustainable energy future, it is a bridge that must be traversed carefully: Diligence will be required to ensure that leakage rates are low enough to achieve sustainability goals.

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Supplementary Materials

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API
American Petroleum Institute

anga
America's Natural Gas Alliance

Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production

Summary and Analysis of API and ANGA Survey Responses

Terri Shires and Miriam Lev-On
URS Corporation and The LEVON Group

FINAL REPORT
June 1, 2012

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Executive Summary

This document presents the results from a collaborative effort among members of the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) to gather data on key natural gas production activities and equipment emission sources - including unconventional natural gas production - that are essential to developing estimates of methane emissions from upstream natural gas production.

API and ANGA members undertook this effort as part of an overall priority to develop new and better data about natural gas production and make this information available to the public. This information acquired added importance in 2011, when the EPA released an inventory of U.S. greenhouse gases (GHG) emissions that substantially increased estimates of methane emissions from Petroleum and Natural Gas Systems. Public comments submitted by both trade associations reflected a number of concerns – most notably that EPA's estimates were based on a small set of data submitted by a limited number of companies in a different context (i.e., data not developed for the purpose of estimating nationwide emissions).

The API/ANGA data set (also referred to as ANGA/API) provides data on 91,000 wells distributed over a broad geographic area and operated by over 20 companies. This represents nearly one-fifth (18.8%) of the estimated number of total wells used in EPA's 2010 emissions inventory.[1] The ANGA/API data set is also more than 10 times larger than the set of wells in one of EPA's key data sources taken from an older Natural Gas Star sample that was never intended for developing nationwide emissions estimates. ***Although more and better data efforts will still be needed, API/ANGA members believe this current collaborative effort is the most comprehensive data set compiled for natural gas operations.***

As Table ES-1 demonstrates, survey results in two source categories – liquids unloading and unconventional gas well re-fracture rates - substantially lower EPA's estimated emissions from natural gas production and shift Natural Gas Systems from the largest contributor of methane emissions to the second largest (behind Enteric Fermentation, which is a consequence of bovine digestion).[2] The right-hand column of this table shows the impact of ANGA/API data on the estimated emissions for each source category. Gas well liquids unloading and the rate at which unconventional gas wells are re-fractured are key contributors to the overall GHG emissions estimated by EPA in the national emissions inventory. For example, methane emissions from liquids unloading and unconventional well re-fracturing accounted for 59% of EPA's estimate for overall natural gas production sector methane emissions. Overall, API/ANGA activity data for these two source categories indicate that EPA estimates of potential emissions from the production sector of "Natural Gas Systems" would be 50% lower if EPA were to use ANGA/API's larger and more recent survey results.

[1] EPA's 2010 national inventory indicates a total of 484,795 gas wells (EPA, 2012).

[2] Table ES-2 of the 2010 national inventory (EPA, 2012).

TABLE ES-1. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA		API/ANGA		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Emissions Total	Metric tons of CH4	% of Revised Emissions Total	API & ANGA - EPA / EPA % Difference
Gas Wells Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

As mentioned above, the differences between EPA and ANGA/API estimates hinge on the following key differences in activity data and thus considerably impact overall emissions from Natural Gas Systems:

- ***Liquids unloading and venting.*** API/ANGA data showed lower average vent times as well as a lower percentage of wells with plunger lifts and wells venting to the atmosphere than EPA assumed. This is particularly significant because liquids unloading accounted for 51% of EPA's total "Natural Gas Systems" methane emissions in the 2010 inventory. Applying emission factors based on ANGA/API data reduces the calculated emissions for this source by 86% (from 4,501,465 metric tons of CH_4 to 637,766 metric tons of CH_4 when compared on an equivalent basis) from EPA's 2010 national GHG inventory.
- ***Re-fracture rates for unconventional wells***. API/ANGA members collected data on re-fracture rates for unconventional wells in two phases. The first phase collected data for all well types (conventional and unconventional), while the second phase targeted unconventional gas wells. Both phases of the survey data show significantly lower rates of well re-fracturing than the 10% assumption used by EPA. As discussed in detail in this report, the re-fracture rate varied from 0.7% to 2.3%. The second phase of the survey gathered data from only unconventional well activity and using the re-fracture rate data from this second phase of the ANGA/API survey reduces the national emission estimate

for this source category by 72%, - from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on an equivalent basis.

This report also discusses an important related concern that the government lacks a single coordinated and cohesive estimate of well completions and well counts. Although the 2010 national GHG inventory appears to under-represent the number of well completions according to the numbers reported through both the API/ANGA data and IHS CERA, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with any certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) all report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of the number of wells that are completed annually, let alone the amount of emissions from them. Natural gas producers strongly believe that the effects of any possible under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

This survey also collected data on centrifugal compressors and pneumatic controllers. While the sample sizes are too small to make strong conclusions, the results discussed in the body of the report indicate that further research is necessary to accurately account for the different types of equipment in this area (e.g., wet vs. dry seal centrifugal compressors and "high bleed," "low bleed," and "intermittent bleed" pneumatic controllers).

As government and industry move forward in addressing emissions from unconventional gas operations, three key points are worth noting:

- ***In addition to the voluntary measures undertaken by industry, more data will become available in the future.*** Emission reporting requirements under Subpart W of the national Greenhouse Gas Reporting Program (GHGRP) went into effect January 1, 2011 with the first reporting due in the fall of 2012. As implementation of the GHGRP progresses from year to year, the natural gas industry will report more complete and more accurate data. If EPA makes use of the data submitted and transparently communicates their analyses, ANGA/API members believe this will increase public confidence in the emissions estimated for key emission source categories of the Natural Gas Systems sector.
- ***Industry has a continuous commitment to improvement.*** It is clear that companies are not waiting for regulatory mandates or incentives to upgrade equipment, or to alter practices like venting and flaring in favor of capturing methane where practical. Instead, operators are seizing opportunities to reduce the potential environmental impacts of their operations. Industry is therefore confident that additional, systematic collection of production sector activity data will not only help target areas for future reductions but also demonstrate significant voluntary progress toward continually 'greener' operations.
- ***Members of industry participating in this survey are committed to providing information about the new and fast-changing area of unconventional oil and gas operations. API and ANGA members look forward to working with the EPA to revise current assessment methodologies as well as promote the accurate and defensible uses of existing data sources.***

1. Overview

The accuracy of GHG emission estimates from unconventional natural gas production has become a matter of increasing public debate due in part to limited data, variability in the complex calculation methodologies, and assumptions used to approximate emissions where measurements in large part are sparse to date. Virtually all operators have comprehensive methane mitigation strategies; however, beyond the requirements of the Environmental Protection Agency's (EPA) Mandatory Reporting Rule or incentives of programs like the EPA's Natural Gas Star program, data is often not gathered in a unified way that facilitates comparison among companies.

In an attempt to provide additional data and identify uncertainty in existing data sets, the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) began a joint study on methane (CH_4) emissions from unconventional gas operations in July 2011. The first part of this section offers context to the decision to conduct this survey, while the second offers a brief introduction to the survey itself.

1.1 Context

Shale gas will undoubtedly play a key role in America's energy future and therefore additional information must be collected to quantify the methane emissions from both conventional and unconventional natural gas production. Meaningful, publicly available data is a priority, especially in light of EPA's 2011 revision of its calculation methodology for Natural Gas Systems in the 2009 national inventory (EPA, 2011b). (EPA added two new sources for unconventional gas well completions and workovers, and also significantly revised its estimates for liquids unloading and made adjustments to other source categories.) These changes substantially increased EPA's estimated GHG emissions for the production sector of the Natural Gas Systems by 204%.

Industry was alarmed by the upward adjustment, especially since previous EPA estimates had been based on a 1996 report prepared by the EPA and GRI – and did not take into account the considerable improvements in equipment and industry practice that have occurred in the fifteen years between 1996 and 2011 (GRI, 1996).

An EPA technical note to the 2009 inventory attributed the changes to adjustments in calculation methods for existing sources, including gas well liquids unloading, condensate storage tanks, and centrifugal compressor seals. EPA also added two new sources not previously included in its inventories, namely unconventional gas well completions and workovers (re-completions) (EPA, 2011e).

Industry did not have an adequate opportunity to examine EPA's rationale for the new emissions factor prior to its initial release. Unlike changes in regulatory requirements, EPA is not required to initiate a formal comment process for changes in methodologies like emission factors and calculations methods in the national GHG inventory. As such, EPA is not compelled to incorporate or consider input provided by stakeholders and experts. Indeed, changes to methodologies are often made without the benefit of dialogue or expert review. Although EPA further acknowledged in the 2010 inventory (released in 2012), that their natural gas calculations needed work, their practice is to continue using the same numbers until adjusted estimates have

been made. It is important to note that EPA has indicated a willingness to engage and discuss this matter with some members of industry; however, no time frame has yet been determined for this discussion.

Under the best of circumstances, EPA had remarkably little information to draw on in determining their new emission factor. Input from industry on this topic was not directly solicited. Specific guidance also did not exist on the international level, nor was it available from other national regulators. A review of the Intergovernmental Panel on Climate Change (IPCC) and other inventories submitted to the United Nations Framework Convention on Climate Change (UNFCCC) indicate that the U.S. is currently the only country to date to differentiate between conventional and unconventional natural gas production. Regulators, academics, and environmentalists around the world therefore considered the new estimated emission factor as an unprecedented development in a controversial issue.

Widespread criticism of the figures revealed problematic methodology and less justification for the underlying numbers than originally anticipated. In a paper entitled *Mismeasuring Methane*, the well-respected energy consultancy IHS CERA succinctly detailed several concerns about the revisions – most notably that EPA's new estimate was based on only four (4) data points that natural gas well operators had submitted voluntarily under the Natural Gas Star Program, which highlights emissions reductions. Together, the four data points cover approximately 8,880 wells – or roughly 2% of those wells covered in the EPA's national greenhouse gas inventory. Those numbers, which were submitted in the context of showcasing achieved emissions reductions and not to estimate emissions, were then extrapolated to over 488,000 wells in the 2009 emissions inventory (IHS CERA, 2011).

With an emerging topic like shale energy development, however, the impact of EPA's revised estimates was enormous. Emission estimates from production using EPA's figures were used to question the overall environmental benefits of natural gas. They were cited widely by unconventional gas opponents - many of whom used the new figures selectively and without caveats like "estimated" to argue against further development of shale energy resources. For example, an article published by ProPublica cited the revised EPA emission factors as "new research" which "casts doubt" on whether natural gas contributes lower GHG emissions than other fossil fuels (Lustgarten, 2011). Many of these studies – e.g., the work of Howarth *et al.* were widely reported in the popular press (Zellers, 2011) with little attention to the quality of analysis behind their conclusions.

Notably, other authors using more robust and defensible scientific methodologies argued that - even with undoubtedly high emissions estimates - natural gas still possessed a lifecycle advantage when its comparative efficiency in electricity generation was taken into account. For example, a study by Argonne National Laboratory utilizing the same EPA data sources concluded that taking into account power plant efficiencies, electricity from natural gas shows significant life-cycle GHG benefits over coal power plants (Burnham, 2011). Unfortunately, the complex technical arguments in these studies generated considerably less media and public attention.

It is important to understand that the ongoing debate about the accuracy of EPA's adjusted emission factor as contained in the 2009 inventory did not keep these numbers from being used in a series of rules that have wide ranging ramifications on national natural gas policies both in the United States and globally. Many countries considering shale energy

development remain bound by the emissions reduction targets in the Kyoto Protocol and their regulatory discussions reflect greenhouse gas concerns. In addition to the very real risk that other countries could adopt the emission factor before the EPA can refine its calculations, the possibility of higher emissions (even if only on paper) might deter other nations from developing their own unconventional energy resources.

By the summer of 2011, it was clear to ANGA/API members (also referred to as API/ANGA members) that gathering additional data about actual emissions and points of uncertainty during unconventional gas production was essential to improve GHG life cycle analysis (LCA) of natural gas for the following reasons: 1) to focus the discussion of emissions from natural gas production around real data; 2) to promote future measurement and mitigation of emissions from natural gas production; and 3) to contribute to improving the emission estimation methods used by EPA for the natural gas sector in their annual national GHG inventory.

1.2 Introduction to the API/ANGA Survey

API and ANGA members uniformly believed that EPA's current GHG emissions estimates for the natural gas production sector were overstated due to erroneous activity data in several key areas - including liquids unloading, well re-fracturing, centrifugal compressors, and pneumatic controllers. Members therefore worked cooperatively to gather information through two data requests tailored to focus on these areas and reasonably accessible information about industry activities and practices. Specifically, information was requested on gas well types, gas well venting/flaring from completions, workovers, and liquids unloading, and the use of centrifugal compressor and pneumatic controllers.

The actual data requests sent to members can be found in Appendix A, and Appendix B provides more detailed data from the ANGA/API well survey information**.**

Survey results and summaries of observations, including comparisons to EPA's emission estimation methods, are provided in the following sections.

2. Well Data

This section examines well data gathered by API and ANGA members. Overall, ANGA/API's survey effort gathered activity data from over 20 companies covering nearly 91,000 wells and 19 of the 21 American Association of Petroleum Geologists (AAPG) basins[3] containing over 1% of the total well count in EPA's database of gas wells. Members believe that the API/ANGA survey represents the most comprehensive data set ever compiled for natural gas operations and, as such, provides a much more accurate picture of operations and emissions.

Information to characterize natural gas producing wells was collected by survey in two parts:

- The first part of the survey requested high-level information on the total number of operating gas wells, the number of gas well completions, and the number of gas well workovers with hydraulic fracturing. Data on over 91,000 wells was collected primarily for 2010, with some information provided for the first half of 2011.
- The second part of the survey requested more detailed well information about key activities. The well information collected through the two surveys is provided in Appendix B.

Section 2.1 looks at overall natural gas well counts, Section 2.2 examines completion data from ANGA/API members, and Section 2.3 briefly identifies several unresolved issues concerning well counts and classifications that could benefit from future analysis for examination. For the purposes of this report, unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

2.1 National Gas Well Counts

To provide context for the information collected by API and ANGA, comparisons were made to information about national gas wells from EPA and the U.S. Energy Information Administration (EIA). Unfortunately, the government lacks a single coordinated and cohesive set of estimates for gas wells.

Industry grew concerned when it became apparent that significant discrepancies existed among different sources of national gas well data. The EPA inventory, the EIA, and IHS all reported different well counts that do not consistently distinguish between key areas like conventional and unconventional wells. Furthermore, there does not appear to be a single technical description for classifying wells that is widely accepted. Without consistent measures and definitions for the quantity and type of wells, it is difficult to reach agreement on the number of unconventional wells completed annually - let alone their emissions.

[3] Basins are defined by the American Association of Petroleum Geologists (AAPG) AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978.

Both the EIA data and the EPA data accompanying the national GHG inventory lack sufficient detail for well classifications to provide a basis for helpful comparison with the survey data reported here. Instead, national well data developed as part of mandatory emissions reporting is used for comparison because it has the most appropriate level of detail in well categories (EPA, 2011d).

In EPA's database gas well count (EPA, 2011d), 21 of the AAPG basins each have more than 1% of the total well count. The API/ANGA survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA database well count is accounted for by wells in those 21 basins, while 95% of the ANGA/API surveyed gas wells are accounted for by those 21 basins. These results are summarized in Table 1 and illustrated in Figure 1. This indicates that the API/ANGA survey results have good representation for the basins with the largest numbers of wells nationally.

TABLE 1. COMPARISON OF GAS WELL COUNT DATA BY AAPG BASIN: SUMMARY STATISTICS

	EPA Database Gas Well Count*	API/ANGA Survey Data	ANGA/API as a % of EPA
Total number of U.S. gas wells	355,082 gas wells	91,028 gas wells	26%
Number of significant AAPG basins**	21 basins	Data on wells in 19 of those 21 basins	90%
Number of wells in significant AAPG basins	325,338 wells	86,759 wells	27%
% of total wells in significant AAPG basins	92%	95%	

* EPA's database gas well count (EPA, 2011d) differs from the well count provided in EPA's 2010 national inventory, but provides more detail on the types of wells. Additional details are provided in Appendix B.

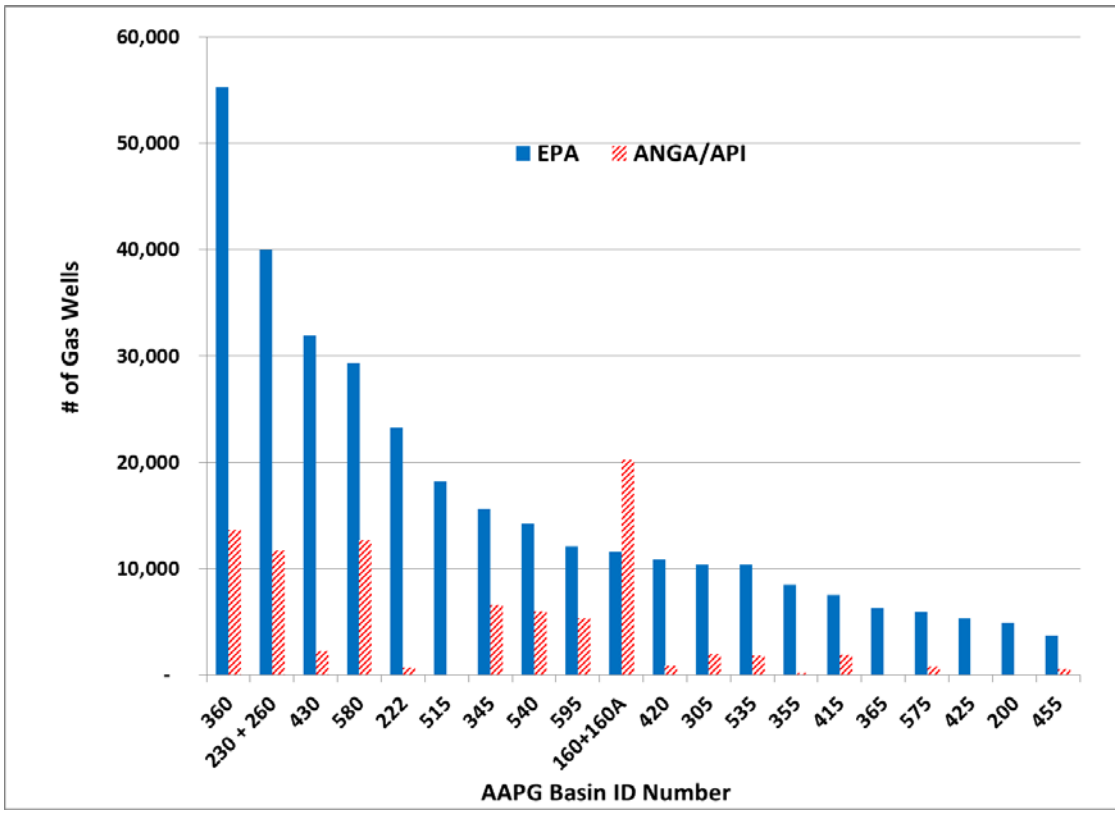
** Significant basins are defined as basins with more than 1% of the total national gas wells.

As shown in Figure 1, the API/ANGA survey results more heavily represent gas wells in specific AAPG basins when compared to EPA's basin-level well counts (EPA, 2011c). Unlike the EPA data, the ANGA/API data is more heavily influenced by AAPG 160 and 160A. AAPG basins 360, 230, and 580 are important for both data sets.

The smaller data set provided by EPA (2011d) may not include all of the Marcellus shale wells (particularly in Pennsylvania), and the well classification system used in this smaller data set could probably be made more rigorous. Although this comparison may not show a perfect distributional match for the basin by basin distribution of the API/ANGA survey data presented here, it does not change the fundamental conclusion of the ANGA/API survey since this data set does cover 90% of the basins and 27% of the national gas well count for the significant basins as reported by EPA (EPA, 2011d). The data discussed in this report provides substantial new information for understanding the emissions from Natural Gas Systems and offers a compelling justification for re-examining the current emission estimates for unconventional gas wells.

Appendix B contains more detail about the industry well data sample compared to the overall data maintained by the government. Unless otherwise noted, further statistical comparisons of well data throughout this paper are done with reference to the EPA data because it was the only one which effectively parsed the data by well type (EPA, 2011d).

FIGURE 1. COMPARISON OF EPA TO API/ANGA GAS WELL COUNT DATA BY AAPG BASIN



2.2 Gas Well Completions

Acknowledging the somewhat different time periods covered, the API/ANGA survey data represents 57.5% of the national data for tight gas well completions and 44.5% of shale gas well completions, but only 7.5% of the national conventional well completions and 1.5% of coal-bed methane well completions. About one-third of the surveyed well completions (2,205) could not be classified into the well types requested (i.e., tight, shale, or coal-bed methane). The survey results for well completions are provided in Table 2 and compared to national data provided to ANGA by IHS.[4]

EPA's 2010 inventory showed 4,169 gas well completions with hydraulic fracturing (EPA, 2012, Table A-122); however, EPA does not provide a breakout of completions by well type (shale gas, tight gas or coal-bed methane). In comparing the EPA 2010 count of gas well completions with hydraulic fracturing (4,169 completions) to both the survey results and data

[4] Data provided in e-mail from Mary Barcella (IHS) to Sara Banaszak (ANGA) on August 29,2011. Data were pulled from current IHS well database and represent calendar year 2009 (2010 data are not yet available).

provided by IHS, it seems that EPA's national GHG inventory underestimates the number of well completions. Even accounting for the difference in time periods (2010 for EPA compared to 2010/2011 data from the ANGA/API survey), the national inventory appears to under-represent the number of well completions.

TABLE 2. API/ANGA SURVEY – SUMMARY OF GAS WELL COMPLETIONS BY NEMS REGION AND WELL TYPE*
(FIRST SURVEY DATA REQUEST PHASE)

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified	Regional Total
API/ANGA Survey Data Gas Well Completions						
Northeast	2	291	3	67	126	489
Gulf Coast	81	588	-	763	374	1,806
Mid-Continent	22	734	-	375	270	1,401
Southwest	425	442	-	346	310	1,523
Rocky Mountain	10		30	977		1,017
Unspecified	-	-	-	-	1,125	1,125
Survey TOTAL	540	2,055	33	2,528	2,205	7,361
% of Survey Total	7.3%	27.9%	0.4%	34.3%	30.0%	
2010 IHS Gas Well Completions						IHS Total
2010 National Well Completions (from IHS)[1]	7,178	4,620	2,254	4,400		18,452
	38.9%	25.0%	12.2%	23.8%		
API/ANGA as % of IHS National Well Counts	7.5%	44.5%	1.5%	57.5%		

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

** EPA's national GHG inventory does not designate gas wells by classifications of "shale", "coal bed methane" or "tight".

As shown in Table 3, the ANGA/API survey noted 7,361 gas well completions for 2010 and the first half of 2011. This is equivalent to approximately 40% of the gas well completions reported by IHS for 2010. Although EPA's 2010 national GHG inventory appears to under-represent the number of gas well completions according to the numbers reported through both the API/ANGA data and the IHS, differences in national well data reporting systems make it difficult to accurately investigate well completion differences with certainty. The EPA inventory, which uses data from HPDI, and the Energy Information Administration (in addition to privately sourced data) - all of which report different well counts that do not consistently distinguish between conventional and unconventional wells. Without a consistent measure for the quantity and type of wells, it is difficult to be confident of the accuracy of how many wells are completed annually, let alone to estimate their emissions. Industry strongly believes that the effects of any current under-representation of well completions will be offset by a more realistic emission factor for the rate of emissions per well.

TABLE 3. SUMMARY OF GAS WELL COMPLETIONS DATA (FIRST SURVEY DATA REQUEST PHASE)

	# Completions for Gas Wells without hydraulic fracturing	# Completions for Gas Wells with hydraulic fracturing	Total Completions
2010 National Well Completions (from EPA; EPA 2012)	702	4,169	4,871
% of National Total	14%	86%	
API/ANGA Survey Well Completions	540	6,821	7,361
% of National Total	7%	93%	
Well Completions from IHS	7,178	11,274	18,452
% of National Total	39%	61%	

Table 4 provides detailed data for well completions from the ANGA/API survey. From the survey, 94% of gas well completions in 2010 and the first half of 2011, were conducted on wells with hydraulic fracturing. About one-half of all gas well completions for this time period were for tight wells, and about one-half of all gas well completions were for vertical wells with hydraulic fracturing. Any differences in totals between Tables 2, 3 and 4 are because these tables were derived from the two different data requests sent to member companies as described previously in the introduction to Section 2.

TABLE 4. API/ANGA SURVEY – ADDITIONAL DETAILS ON GAS WELL COMPLETIONS (SECOND SURVEY DATA REQUEST PHASE)

	# Completions for Gas Wells with hydraulic fracturing (HF)				Gas Wells without hydraulic fracturing		Total Completions
	# Vertical wells completions	# Horizontal well completions	Total Wells with HF	% of Wells with HF	# Completions	% of Wells without HF	
TOTAL Conventional	315	57	372	69%	164	31%	536
TOTAL Shale	317	1,863	2,180	99%	30	1%	2,210
TOTAL Tight	2,054	368	2,422	96%	106	4%	2,528
TOTAL Coal Bed Methane	27	3	30	91%	3	9%	33
TOTAL OVERALL	**2,713**	**2,291**	**5,004**	**94%**	**303**	**6%**	**5,307**

The following points summarize survey information provided in Tables 2, 3 and 4. These tables represent a snapshot of well activity data during this time.

- Overall, the survey showed 94% of the 5,307 wells reported in the API/ANGA data set as completed in 2010 and the first half of 2011 used hydraulic fracturing.
- *536 conventional gas wells were completed in 2010 and the first half 2011.*
  - 59% were vertical wells with hydraulic fracturing,
  - 11% were horizontal wells with hydraulic fracturing, and
  - 31% were wells without hydraulic fracturing.
- *2,210 shale gas wells were completed in 2010 and the first half 2011.*
  - 14% were vertical wells with hydraulic fracturing,
  - 84% were horizontal wells with hydraulic fracturing, and
  - 1% were wells without hydraulic fracturing.
- *2,528 tight gas wells were completed in 2010 and the first half 2011.*
  - 81% were vertical wells with hydraulic fracturing,
  - 15% were horizontal wells with hydraulic fracturing, and
  - 4% were wells without hydraulic fracturing.
- *33 coal-bed methane wells were completed in 2010 and the first half 2011.*
  - 82% were vertical wells with hydraulic fracturing,
  - 9% were horizontal wells with hydraulic fracturing, and
  - 9% were wells without hydraulic fracturing.

2.3 Data Limitations Concerning Wells

In response to follow-up questions on well data, EPA indicated that they classified gas well formations into four types (conventional, tight, shale, and coal-bed) (EPA, 2011d). When developing the gas well classifications, EPA applied their judgment where data were not available in the database. ANGA and API are interested in using the well database compiled by IHS or a similar database, to more completely classify gas wells at some point in the future. The API/ANGA survey did not specifically define conventional wells for collecting the well data presented in this section, leaving the respondents to determine the classification of wells based on their knowledge of the well characteristics or state classifications. As such, this well classification may vary somewhat according to the respondent's classification of wells.

It should be noted that there is not a generally accepted definition for "gas wells." Producers might be producing from several zones in the same formation, and different states define "gas" or "oil" wells differently due to the historical structure of royalties and revenues. There is also no commonly used definition of "conventional" gas wells. Thus, different definitions of these terms may have produced inconsistency in the classification of wells between gas and oil, and conventional and unconventional for the surveyed results, as well as for the EPA and EIA national data. For the purposes of this report, unconventional wells are considered to be

shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically.

3. Gas Well Liquids Unloading

Gas well clean ups also known as liquids unloading accounts for 51% of total CH_4 emissions from the natural gas production sector in EPA's national GHG inventory (EPA, 2012).[5] This was a considerable increase from the 6% of CH_4 emissions that liquids unloading represented in the 2008 inventory. The accuracy of assumptions regarding this activity was therefore a major concern to API/ANGA members.

As the name indicates, liquids unloading is a technique to remove water and other liquids from the wellbore so as to improve the flow of natural gas in conventional wells and unconventional wells.

In EPA's national inventory, emissions from gas well liquids unloading are based on the following assumptions:

- 41.3% of conventional wells require liquids unloading.
- 150,000 plunger lifts are in service, which equates to 42% of gas wells.
- The average gas well is blown down to the atmosphere 38.73 times per year.
- The average casing diameter is 5 inches.
- A gas well is vented to the atmosphere for 3 hours once the liquids are cleared from the well.

The ANGA/API survey gathered activity and emissions related information for gas well liquids unloading. Information was received covering eight conventional well data sets and 26 unconventional well data sets. The following information was requested:

- Geographic area represented by the information provided;
- Time period – data were annualized to 12 months if the information was provided for a partial year;
- Number of operated gas wells represented by the information provided;
- Number of gas wells with plunger lift installed;
- Number of gas wells with other artificial lift (beam pump; ESP; etc.);
- Total number of gas well vents;
- Number of wells with and without plunger lifts that vent to the atmosphere;
- Total count of gas well vents for time period with and without plunger lifts;
- Average venting time for wells with and without plunger lifts;
- Average daily production of venting gas wells (Mcf/day);
- Average depth of venting wells (feet);

[5] See EPA Table A-129, of Annex 3 of the 2010 inventory report.

- Average casing diameter of venting gas wells (inches);
- Average tubing diameter of venting gas wells with plunger lift (inches); and
- Average surface pressure - venting gas wells (psig).

Table 5 summarizes the results from the API/ANGA survey and compares the results to the assumptions EPA uses to estimate emissions for this source in the national GHG inventory.

The ANGA/API data differed from EPA's assumptions in several ways:

1) API/ANGA showed lower percentages of wells with plunger lifts;
2) API/ANGA data indicated lower percentages of wells venting to the atmosphere;
3) API/ANGA data showed lower average vent times than EPA's numbers; and
4) Casing diameters from the API/ANGA survey were comparable to EPA's assumption of 5 inches.

TABLE 5. ANGA/API SURVEY – SUMMARY OF LIQUIDS UNLOADING DATA

Parameter	API/ANGA Survey		EPA Assumptions
	Conventional Wells	Unconventional Wells	
Number of gas wells with plunger lifts	10%	45%	42%
Number of gas wells with other artificial lift (beam pump, ESP, etc.)	25%	7%	
Number of gas wells vented to the atmosphere for liquids unloading	11%	16%	41.3%
# vents per well (weighted average)	303.9 (all data)* 32.4 (w/o outliers) **	33.6	38.7
Average venting time per vent (weighted average)			3 hours
With plunger lifts	0.25 hours	0.77 hours	
Without plunger lifts	1.78 hours	1.48 hours	
Weighted Average casing diameter	4.64 inches	5.17 inches	5 inches
Weighted Average tubing diameter	2.27 inches	2.43 inches	
Average Emission factor, Mscf/well			
With plunger lifts	823 (all data)* 14.7 (w/o outliers)**	196	
Without plunger lifts	56.4	318	
Weighted average Methane emission factor, Mscf CH4/well	175*		1,316

* Includes all liquids unloading data from the ANGA/API survey

** Excluding two high data points

When examining Table 5, it is important to note the presence of several outliers. Two data responses for operations with conventional wells reported very high frequencies of vents to the atmosphere. These data sets represent 174 gas wells with plunger lifts (out of a total 788 gas wells with plunger lifts represented by the total data set) located in the Mid-Continent region. The wells represented by these data points have plunger lifts that vent to the atmosphere for each plunger cycle. The information was confirmed by the two data respondents and is an artifact of the plunger control for these wells which results in very short venting durations (between 4 and 5 minutes) for each plunger cycle. As a result, accounting for the high frequency of plunger lift cycles for these wells results in a high average vent frequency, but still produces a lower emission factor than the EPA assumptions.

Excluding these two data points, the API/ANGA survey data for the number of vents per well was comparable to EPA's assumed frequency. Moreover, even with the high frequency of vents from these wells, the emissions are much lower than EPA's estimates (see Table 6).

TABLE 6. ANGA/API SURVEY –LIQUIDS UNLOADING EMISSIONS COMPARISON

NEMS Region	API/ANGA Survey		EPA Inventory			API & ANGA - EPA EPA % Difference in Emissions
	Emission Factor, Mscf CH4/well	Estimated Emissions, tonnes CH_4	# wells	Emission Factor, Mscf CH_4/well	Estimated Emissions, tonnes CH_4 *	
Northeast	136	202,503	77,931	1,360	2,027,265	-90%
Mid Continent	392	235,813	31,427	703	422,893	-44%
Rocky Mountain	177	90,387	26,620	690	351,672	-74%
Southwest	36	7,913	11,444	865	189,407	-96%
Gulf Coast	169	101,150	31,331	2,519	1,510,259	-93%
West Coast	No data for this region		638	1,492	Excluded for consistent comparison	
TOTAL	175 (weighted average)	637,766	179,391		4,501,465	-86%

*EPA estimated emissions = # wells × EPA emission factor, converted to mass emissions based on 60 degrees F and 14.7 psia

These variances among operators in ANGA/API data demonstrate the challenge of applying national emissions estimates to conditions in which there can be considerable variation in wells and operating techniques, among and even within various regions. As member companies have noted in various comments to regulators, oil and natural gas production operations vary considerably according to factors such as local geology, hydrology, and state law.

EPA noted that wells equipped with plunger lifts have approximately 60% lower emissions from liquids unloading than wells without plunger lifts (EPA, 2011b). From the API/ANGA survey, an emission reduction of about 38% was observed for the unconventional

wells equipped with plunger lifts compared to those without plunger lifts. However, Table 5 indicates that for conventional gas wells, the average emission factor is higher for wells with plunger lifts compared to those without when the two high data points are included. Excluding the two high data points, the emission factor for conventional wells with plunger lifts is 74% lower than the emission factor for conventional wells without plunger lifts.

One reason for this discrepancy in the data may be that EPA has acknowledged that their current estimation method for liquids unloading does not account for activities used to reduce CH_4 emissions by many different artificial lift methods used in industry. According to Natural Gas Star Reports, the applicable emission reductions range from 4,700 to 18,250 Mscf/yr for plunger lift systems (EPA, 2006); however, since the emission reductions are reported separate from the emission estimate in the national inventory, they cannot be linked back to EPA emission source categories.

Emissions were calculated by applying Equation W-8 or W-9 from the EPA GHG reporting rule in 40 CFR 98 Subpart W, where Equation W-8 applies to gas wells without plunger lifts, and Equation W-9 applies to gas wells with plunger lifts. Appendix C summarizes the data collected and estimated emissions. The emission results are shown in Table 6 by NEMS region for comparison to EPA's emission estimates. The ANGA/API survey averaged the emission factors data within each NEMS region for conventional and unconventional wells combined. The emission results shown in Table 6 were determined by applying the API/ANGA emission factors and EPA emission factors, respectively, to the total number of wells requiring liquids unloading from the 2010 national GHG inventory.

As production companies continue to collect information for EPA's mandatory GHG reporting program, better information on liquids unloading frequency and emissions will be available. One area that would benefit from additional information is an investigation of regional differences, or plunger lift control practices, in view of the high frequency of vents observed for two data sets containing conventional gas wells with plunger lifts in the Mid-Continent region.

Key findings of the ANGA/API survey on liquids unloading are:

- ***For all of the NEMS regions, the API/ANGA survey data resulted in lower emission estimates than EPA estimated for the 2010 national GHG inventory when compared on a consistent basis.***
- ***Overall, the change in emission factors based on data collected from the ANGA/API survey reduces estimated emissions for this source by 86% from the emissions reported in EPA's 2010 national GHG inventory.***

4. Hydraulic Fracturing and Re-fracturing (Workovers)

A well workover refers to remedial operations on producing natural gas wells to try to increase production. Starting with the 2009 inventory, EPA split the estimation of emissions from producing gas wells into conventional (i.e., without hydraulic fracturing) and unconventional (i.e., with hydraulic fracturing). For workovers of wells without hydraulic fracturing, the 2009 and 2010 national inventories used emission factors of the same order of magnitude as the 2008 inventory (2,454 scf of CH_4/workover). In contrast, the unconventional (with hydraulic fracturing) well workover emission factor increased by a factor of three thousand (3,000).

EPA did acknowledge that the new emission factor for well workovers was based on limited information (EPA, 2011a). Moreover, several publications including *Mismeasuring Methane* by IHS CERA underscored the perils of extrapolating estimates using only four (4) data points representing approximately two percent (2%) of wells – particularly when the data was submitted in the context of the Natural Gas Star program, which was designed to highlight emissions reduction options (IHS CERA, 2011). Unfortunately, even if the EPA's workover factor is high, it must be used in estimated emissions calculations until it is officially changed.

EPA's new emission factor is 9.175 MMscf of natural gas per re-fracture (equivalent to 7.623 MMscf CH_4/re-fracture). Additionally, EPA used this new emission factor in conjunction with an assumed re-fracture rate of 10% for unconventional gas well workovers each year to arrive at their GHG emission estimate for this particular category.

4.1 API/ANGA Survey

The ANGA/API survey requested counts for gas well workovers or re-fractures in two separate phases of the survey, covering 91,028 total gas wells (Table 7 covering 2010 and first half of 2011 data) and 69,034 unconventional gas wells (Table 8, 2010 data only), respectively.

The first phase of the survey was part of the general well data request. Counts of workovers by well type (conventional, tight, shale, and coal bed methane) and by AAPG basin were requested. The frequency of workovers was calculated by dividing the reported workover rates by the reported total number of each type of gas well. These results are summarized in Table 7, which includes a comparison to national workover data from EPA's annual GHG inventory. The high number of workovers in the Rocky Mountain region is discussed further below.

Table 7 indicates that even for the high workover rates associated with unconventional tight gas wells, the workover rate is much less than EPA's assumed 10% of gas wells re-fractured each year. Based on this first phase of the survey,

- The overall workover rate involving hydraulic fracturing was 1.6%.
- However, many of these workovers were in a single area, AAPG-540, where workovers are known to be conducted more routinely than in the rest of the country (as described in more detail below Table 8). Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.7%

- For all unconventional wells in Table 7, the overall workover rate involving hydraulic fracturing was 2.2%. Excluding AAPG 540, the overall workover rate involving hydraulic fracturing was 0.9%.

TABLE 7. API/ANGA SURVEY – SUMMARY OF GAS WELL WORKOVERS WITH HYDRAULIC FRACTURING IN 2010 AND FIRST HALF OF 2011 BY NEMS REGION AND WELL TYPE (FIRST PHASE DATA SURVEY)

NEMS Region	Conventional Wells	Unconventional Wells			
		Shale	Coal-bed Methane	Tight	Unspecified
Northeast	-	-	-	-	-
Gulf Coast	-	5	-	38	73
Mid-Continent	8	1	-	73	33
Southwest	60	25	-	8	7
Rocky Mountain	4	-	25	901	-
West Coast	-	-	-	-	-
Unspecified	-	-	-	-	200
Survey TOTAL	72	31	25	1,020	313
		1,076			
% of national	0.3%	21.3%			
Overall Survey Total % of national	1,461 5.6%				

National Workover Counts (from EPA's 2010 national inventory)	Conventional Wells	Unconventional Wells
	21,088	5,044
	80.7%	19.3%
	26,132	

	Conventional Wells	Unconventional Wells			
		Shale	Coal-bed Methane	Tight	Unspecified
% Workover Rate with Hydraulic Fracturing (from ANGA/API Survey)	0.3%	0.3%	0.5%	3.0%	2.4%
Tight w/out AAPG 540				0.5%	
Unconventional Wells		2.2%			
W/out AAPG 540		0.9%			
All Wells	1.6%				
All Wells w/out AAPG 540	0.7%				

Also, the ANGA/API survey collected information on the number of workovers for vertical and horizontal unconventional gas wells. Nearly 99% of the unconventional gas well workovers were on vertical wells. Additionally, 18% of the gas well workovers from the API/ANGA survey were conducted on gas wells without hydraulic fracturing.

A second phase of the survey was conducted which targeted collecting gas well re-fracture information for 2010 to provide a better estimate than EPA's assumption that 10% of wells are re-fractured each year. This portion of the ANGA/API survey requested information just for "unconventional" gas wells (i.e., those located on shale, coal-bed methane, and tight formation reservoirs), where the formations require fracture stimulation to economically produce gas. A re-fracture or workover was defined for this second phase of the survey as a re-completion to a different zone in an existing well or a re-stimulation of the same zone in an existing well. These results are summarized in Table 8.

While there likely is significant overlap of unconventional well data reported in the first and second phases of the survey (which covered over 62,500 unconventional wells and 69,000 unconventional wells respectively), combined these data indicate an unconventional well re-fracture rate of 1.6% to 2.3% including AAPG 540 and 0.7% to 1.15% excluding AAPG 540.

AAPG Basin 540 (i.e. DJ Basin) which is part of the Rocky Mountain Region stands out in Tables 7 and 8. After four (4) to eight (8) years of normal production decline, the gas wells in this basin can be re-fractured in the same formation and returned to near original production. Success of the re-fracture program in the DJ Basin is uniquely related to the geology of the formation, fracture reorientation, fracture extension and the ability to increase fracture complexity. Also, most DJ Basin gas wells are vertical or directional, which facilitates the ability to execute re-fracture operations successfully and economically. These characteristics result in a high re-fracture or workover rate specific to this formation.

ANGA and API believe the high re-fracture rate observed in the DJ Basin is unique and not replicated in other parts of the country. There may be a few other formations in the world that have similar performance, but the successful re-fracture rate in the DJ Basin is not going to be applicable to every asset/formation and there is no evidence of the high re-fracture rate in any of the other 22 AAPGs covered in the API/ANGA survey. It is highly dependent on the type of rock, depositional systems, permeability, etc. For these reasons, re-fracture rates for tight gas wells and all gas wells with and without AAPG Basin 540 are summarized in Tables 7 and 8.

TABLE 8. API/ANGA SURVEY – SUMMARY OF 2010 GAS WELL WORKOVERS ON UNCONVENTIONAL WELLS BY AAPG BASIN AND NEMS REGION (SECOND PHASE SURVEY DATA)

NEMS Region	AAPG	Number of Unconventional Operating Gas Wells	Number of Hydraulic Fracture Workovers on Previously Fracture Stimulated Wells	% Wells re-fractured per year	Regional % Wells re-fractured per year
Northeast	160	1,976	0	0.00%	0%
	160A	760	0	0.00%	
Gulf Coast	200	2	0	0.00%	0.91%
	220	649	2	0.31%	
	222	629	3	0.48%	
	230	820	4	0.49%	
	250	13	0	0.00%	
	260	2,830	36	1.27%	
Mid-Continent	345	3,296	11	0.33%	0.95%
	350	213	3	1.41%	
	355	282	8	2.84%	
	360	7,870	89	1.13%	
	375	12	0	0.00%	
	385	1	0	0.00%	
	400	64	0	0.00%	
Southwest	415	1,834	0	0.00%	1.04%
	420	838	8	0.95%	
	430	1,548	36	2.33%	
	435	2	0	0.00%	
Rocky Mountain	515	1	0	0.00%	4.7%
	540	5,950	866	14.55%	
	580	8,197	8	0.10%	
	595	5,222	32	0.61%	
Not specified		26,025	487	1.87%	1.87%
Unconventional TOTAL (all wells)		**69,034**	**1,593**	**2.31%**	
Unconventional Median		790	3		
Rocky Mountain Region Unconventional Total		19,370	906	4.68%	
Unconventional TOTAL (Without AAPG 540)		63,084	727	1.15%	

4.2 WRAP Survey

Other information on re-fracture rates is available in a survey conducted by the Western Regional Air Partnership (WRAP). WRAP conducted a survey of production operators in the Rocky Mountain Region (Henderer, 2011) as part of the initiative to develop GHG reporting guidelines for a regional GHG cap and trade program.

Within each basin in this region, the top oil and gas producers were identified and invited to participate in the survey. The goal was to have operator participation that represented 80% of the production for the region. The spreadsheet survey requested information on the completions, workovers, and emissions associated with these activities. An emission factor and frequency of re-fracturing was developed for each basin as a weighted average of the operator responses.

The re-fracture rates from the WRAP survey are shown in Table 9 (Henderer, 2011).

TABLE 9. WRAP SURVEY – SUMMARY OF GAS WELL WORKOVERS BY AAPG BASIN FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	# Wells represented by survey	# Wells Recompleted	% Recompleted
515	4,484	121	2.70%
530	731	5	0.68%
535	4,982	201	4.03%
540	8,247	636	7.71%
580	3,475	14	0.40%
595	4,733	275	5.81%
Total	26,652	1,252	
Weighted average			4.70%

AAPG Basin 540 results in the highest re-fracture rate for this data set, consistent with the ANGA/API survey as noted above. It is noteworthy that, while there are differences among individual AAPG Basin results, the weighted average re-fracture rate from the WRAP survey in 2006 is the same as the Rocky Mountain regional 4.7% re-fracture rate from the API/ANGA survey shown in Table 8.

4.3 Impact of Completions and Re-fracture Rate Assumptions

Table 10 compares the considerable reduction in the national GHG inventory that would result from applying a lower re-fracture rate.

EPA indicated that the national inventory assumes 10% of unconventional gas wells are re-fractured each year. Table 10 replaces this value with results from the ANGA/API survey. A re-fracture rate of 1.15% is applied to unconventional gas wells in the Mid-Continent and Southwest regions (No unconventional gas wells were assigned to the Northeast and Gulf Coast regions. The West Coast region is not shown since the API/ANGA survey did not include any responses for gas well operations in this region.) A re-fracture rate of 4.7% is applied to unconventional gas wells in the Rocky Mountain region.

With these adjustments to the re-fracture rate for unconventional gas wells, the national emission estimate is reduced by 72% for this emission source category, from 712,605 metric tons of CH_4 to 197,311 metric tons of CH_4 when compared on a consistent basis.

4.4 Completion and Re-fracture Emission Factor

In the 2009 GHG national inventory, EPA applies an emission factor of 2,454 scf CH_4/event for conventional gas well workovers, while the emission factor for unconventional gas well completions and workovers was increased to 7,623,000 scf CH_4/event (EPA, 2011b). Similarly, for the 2010 national GHG inventory, EPA maintained the emission factor of 2,454 scf CH_4/event for gas well workovers without hydraulic fracturing, but applied an average emission factor of 7,372,914 to gas well workovers with hydraulic fracturing (EPA, 2012). (EPA applies slightly different emission factors for each NEMS region based on differing gas compositions.)

The ANGA/API survey focused on activity data and did not collect data to revise the emission factor for unconventional gas well completions and workovers.

TABLE 10. API/ANGA SURVEY –GAS WELL WORKOVER EMISSIONS COMPARISON

NEMS Region	Well type	2010 EPA National Inventory # workover	Adjusted # workovers (based on API/ANGA survey)	2010 EPA National Inventory		Revised Emissions, tonnes CH_4 (based on ANGA/API survey)	API & ANGA - EPA EPA % Difference
				Emission Factor, scf CH_4/workover	Estimated Emissions, tonnes CH_4*		
Northeast	Wells without Hydraulic Fracturing	8,208	8,208	2,607	409	409	
	Wells with Hydraulic Fracturing	0	0	7,694,435	0	0	
Mid Continent	Wells without Hydraulic Fracturing	3,888	3,888	2,574	191	191	
	Wells with Hydraulic Fracturing	1,328	153	7,672,247	194,950	22,462**	-89%
Rocky Mountain	Wells without Hydraulic Fracturing	3,822	3,822	2,373	174	174	
	Wells with Hydraulic Fracturing	2,342	1,100	7,194,624	322,402	151,432**	-53%
Southwest	Wells without Hydraulic Fracturing	1,803	1,803	2,508	87	87	
	Wells with Hydraulic Fracturing	1,374	158	7,387,499	194,217	22,382**	-89%
Gulf Coast	Wells without Hydraulic Fracturing	3,300	3,300	2,755	174	174	
	Wells with Hydraulic Fracturing	0	0	8,127,942	0	0	
TOTAL					712,605	197,311	-72%

* EPA Estimated emissions = 2010 # Workovers x EPA 2010 Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

** Revised emissions = Adjusted # Workovers x Emission Factor, converted to mass emissions based on 60°F and 14.7 psia.

Emissions Data from WRAP Study

The WRAP study discussed in Section 4.2 also gathered data on emissions from completions. This information supports a revised emission factor but was reported by sources outside the ANGA/API data survey. The results are summarized in Table 11. The WRAP emission factor is 78% lower than EPA's emission factor (9.175 MMscf gas/event). The WRAP survey did not provide a methodology for determining emissions data.

TABLE 11. WRAP SURVEY – SUMMARY OF COMPLETION EMISSIONS FOR THE ROCKY MOUNTAIN REGION, 2006 DATA

AAPG Basin	Weighted average gas emissions from completion, Mcf gas/well	# completions represented
515	167	207
530	268	54
535	76	642
540	59	608
580	6,559	283
595	4,053	819
Total		2,613
Weighted average	2,032 Mcf/well	

4.5 Data Limitations for Completion and Re-fracture Emissions

Although the data sets are limited, it appears that EPA's assumed re-fracture rate of 10% is a significant overestimate. Information from the API/ANGA survey indicates that even including what appears to be unique activity in AAPG-540, the re-fracture rate is much less frequent, ranging from 1.6% to 2.3% based on two sets of survey information (Tables 7 and 8, respectively). The re-fracture rate for AAPG Basin 540 appears to be higher than other areas in the U.S. due to unique geologic characteristics in that region (4.7% based on a weighted average of data reported for that region). Without AAPG Basin 540, the national rate of re-fracturing is between 0.7% and 1.15% of all gas wells annually.

Additionally, limited information on the emissions from completions and workovers with hydraulic fracturing indicate that EPA's GHG emission factor for these activities is significantly overestimated. It is expected that better emissions data will develop as companies begin to collect information for EPA's mandatory GHG reporting program (EPA, 2011c).

5. Other Surveyed Information

EPA had indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking. Note that the need for better equipment data persists throughout the majority of the U.S. inventory and is not unique to the oil and natural gas industry. The ANGA/API survey requested the following information related to centrifugal compressors and pneumatic devices:

- The number of centrifugal compressors, reported separately for production/gathering versus processing;
- The number of centrifugal compressors with wet versus dry seals, reported separately for production/gathering versus processing;
- The number of pneumatic controllers, classified as "high-bleed," "low-bleed," and "intermittent," reported separately for well sites, gathering/compressor sites, and gas processing plants; and
- The corresponding number of well sites, gathering/compressor sites, and gas processing plants, associated with the pneumatic controller count.

5.1 Centrifugal Compressors

Processing Facilities

The API/ANGA survey collected the equivalent of 5% of the national centrifugal compressor count for gas processing operations (38 centrifugal compressors from the survey, compared to 811 from EPA's 2010 national GHG inventory). For the gas processing centrifugal compressors reported through the survey, 79% were dry seal compressors and 21% were wet seals. EPA's 2010 national inventory reported 20% of centrifugal compressors at gas processing plants were dry seal, and 80% were wet seal. EPA's emission factor for wet seals (51,370 scfd CH_4/compressor) is higher than the emission factor for dry seals (25,189 scfd CH_4/compressor).[6]

Based on the ANGA/API survey, EPA appears to be overestimating emissions from centrifugal compressors. If the small sample size from the API/ANGA survey is representative, non-combustion emissions from centrifugal compressors would be 173,887 metric tons of methane compared to 261,334 metric tons of methane from the 2010 national inventory (when applying industry standard conditions of 60 °F and 14.7 psia to convert volumetric emissions to mass emissions). Although based on very limited data, if the ANGA/API survey results reflect the population of wet seal versus dry seal centrifugal compressors, the emissions from this source would be reduced by 34% from EPA's emission estimate in the national inventory. Better data on the number of centrifugal compressors and seal types will be available from companies reporting to EPA under the mandatory GHG reporting program.

[6] EPA Table A-123, of Annex 3 of the 2010 inventory report.

Production and Gathering Facilities

Very few of the data sets reported through the API/ANGA survey indicate counts of centrifugal compressors associated with production/gathering operations - only 550 centrifugal compressors from 21 participating companies. EPA's 2010 GHG inventory did not include centrifugal compressors in production/gathering operations. On a well basis, the survey responses equate to 0.07 centrifugal compressors per gas well, with 81% dry seal centrifugal compressors and the remaining wet seal compressors. Information reported through EPA's mandatory GHG reporting program will provide additional information to account for GHG emissions from centrifugal compressors in production operations.

5.2 Pneumatic Controllers

Table 12 summarizes the survey responses for pneumatic controllers. For each type of location – gas well sites, gathering compressor sites, and gas processing plants – the count of the number of sites represented by the survey data is shown. Table 12 also shows the percent of each pneumatic controller type for each type of location.

TABLE 12. ANGA/API SURVEY –PNEUMATIC CONTROLLER COUNTS

	Gas Well Sites		Gathering/ Compressor Sites		Gas Processing Plants	
# wells, sites or plants	48,046 wells		1,988 sites		21 plants	
# controllers/well, site or plant	0.99 per well		8.6 per site		7.8 per plant	
# Low Bleed Controllers	12,850	27%	5,596	33%	117	71%
# High Bleed Controllers	11,188	24%	1,183	7%	47	29%
# Intermittent Controllers	23,501	49%	10,368	60%	0	0%

The survey requested that the responses designate pneumatic controllers as either "high bleed", "low bleed", or "intermittent" following the approach each company is using for Subpart W reporting. For example, Subpart W defines high-bleed pneumatic devices as automated, continuous bleed flow control devices powered by pressurized natural gas where part of the gas power stream that 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 6 standard cubic feet per hour (EPA, 2011c).

EPA does not currently track pneumatic controllers by controller type in the national inventory. This information will be collected under 40 CFR 98 Subpart W starting in September 2012. From the API/ANGA survey, intermittent bleed controllers are the more prevalent type at gas well sites and gathering/compressor sites, while gas plants predominately use low-bleed controllers. No intermittent controllers were reported for gas plants by the survey respondents.

Table 13 compares emission results based on applying the emission factors from the EPA's GHG reporting rule to emissions presented in the 2010 national GHG inventory, using the counts of pneumatic controller from the ANGA/API survey for production operations.

For production, the EPA national inventory combines pneumatic controller counts associated with large compressor stations with pneumatic controllers in production. An emission factor for each NEMS region is applied to the count of total controllers in each NEMS region. For this comparison, a weighted average emission factor of 359 scfd CH_4/device was applied to the count of pneumatic controllers located at well sites and gathering/compressor sites.

Under the EPA mandatory reporting rule (40 CFR 98 Subpart W), separate emission factors are applied to pneumatic controllers based on the controller type and whether the controller is located in the Eastern or Western region of the United States, as specified in the rule (EPA, 2011c). For this comparison, an average of the eastern and western emission factors is applied to each device type in computing the emission estimates resulting from the EPA GHG reporting rule.

TABLE 13. PNEUMATIC CONTROLLER EMISSION COMPARISON – PRODUCTION OPERATIONS

	API/ANGA Survey Count of Controllers			EPA GHG Reporting Rule (Subpart W)		2010 National GHG Inventory	
	Gas Well Sites	Gathering/ Compressor Sites	Total	Emission Factor,* scfh CH_4/device	Emissions, tonnes CH_4/yr	Emission Factor, scfd CH_4/device	Emissions, tonnes CH_4/yr
# Low Bleed Controllers	12,850	5,596	18,446	1.58	4,885	359	46,286
# High Bleed Controllers	11,188	1,183	12,371	42.35	87,814		31,042
# Intermittent Controllers	23,501	10,368	33,869	15.3	86,856		84,987
Total			64,686		179,556		162,315

* Emission factors shown are the average of the eastern and western emission factors from Table W-1A (EPA, 2011c).

Based on the types of pneumatic controllers reported in the ANGA/API survey, EPA's mandatory GHG reporting rule could increase CH_4 emissions 11% over the pneumatic controller portion of the 2010 national GHG inventory. To put this in context, in EPA's inventory report for 2010, emissions from pneumatic controllers accounted for approximately 13% of CH_4 emissions from the natural gas field production stage. Any increase from that initially reported data, however, will likely represent a worst case scenario. It is important to remember that pneumatic controllers operate only intermittently, so variability such as the frequency and duration of the activations will be important information to consider when defining an accurate and effective reporting regime for these sources.

EPA's mandatory GHG reporting rule does not require reporting emissions from pneumatic controllers at gas processing plants, so no emission factors are specified. The GHG national inventory applies an emission factor of 164,721 scfy CH_4 per gas plant for pneumatic controllers. For the national inventory, this results in 1,856 tonnes CH_4 emissions - a very small contribution to CH_4 emissions from onshore oil and gas operations.

6. Conclusions

API and ANGA members believe this to be the most comprehensive set of natural gas data to date and are pleased to share these results with both regulators and the public.

Based on the information gathered from member companies during this project, it appears that EPA has overstated several aspects of GHG emissions from unconventional natural gas production. As summarized in Table 14, the ANGA/API survey data results in significantly lower emission estimates for liquids unloading and unconventional gas well refracturing when compared to EPA's emission estimates in the national inventory. Using the combined emission estimates from the survey for these two key emission sources would indicate a 50% reduction in calculated natural gas production sector emissions compared to EPA's estimates. This reduction would shift Natural Gas Systems from the largest to the second largest producer of methane emissions (approximately 123.4 MMT CO_2e in lieu of 215.4 MMT CO_2e), behind Enteric Fermentation (which is a consequence of bovine digestion, at 141.3 MMT CO_2e).

TABLE 14. EMISSION COMPARISON BETWEEN EPA AND INDUSTRY DATA

Source Category	EPA National Inventory		API/ANGA Survey		Impact on Source Category Emissions
	Metric tons of CH4	% of EPA Production Total	Metric tons of CH4	% of Revised Production Total	API & ANGA - EPA / EPA % Difference in Emissions
Liquids Unloading	4,501,465 *	51%	637,766	14%	-86%
Unconventional Well Re-fracture Rates	712,605 *	8%	197,311	4%	-72%
Other Production Sector Emissions**	3,585,600	41%	3,585,600	81%	
Total Production Sector Emissions	8,799,670		4,420,677		-50%

* EPA's estimates are adjusted to industry standard conditions of 60 degrees F and 14.7 psia for comparison to the ANGA/API emission estimates.

**The "Other Production Sector Emissions" are comprised of over 30 different source categories detailed in Table A-129 in the Annex of the EPA's 2012 national inventory. The "Other Production Sector Emissions" are the same values for this comparison between the EPA national inventory and the API/ANGA survey to focus the comparison on quantified differences in emission estimates for gas well liquids unloading and unconventional well re-fracture rates.

This project was directed toward gathering more robust information on workovers, completions, liquids unloading, centrifugal compressors, and pneumatic controllers with the intent of supporting revisions to the activity factors used in EPA's national inventory and cited

by many media publications. Although limited information was collected on centrifugal compressors and pneumatic controllers, the survey results indicated potential additional differences, which are not included in the Table 14 comparison, when comparing total emissions from all sources to the national inventory. Additional future data collection efforts, including more detailed reporting under Subpart W of the GHGRP will likely resolve these differences and continue to inform the overall natural gas emissions data.

In the meantime, however, while API and ANGA recognize that the data collected for this report represents a sample of the universe of natural gas wells operating in the U.S., we believe that the conclusions drawn from the data analysis are relevant and representative of natural gas production as whole. In EPA's gas well count, 21 of the AAPG basins each have more that 1% of the total well count. The ANGA/API survey has wells from 19 of those 21 basins. In terms of wells represented by these basins, 92% of the total EPA well count is accounted for by wells in those 21 basins, while 95% of the API/ANGA surveyed gas wells are accounted for by those 21 basins. This indicates that the ANGA/API survey results have good representation for the basins with the largest numbers of wells nationally.

Industry also believes that the systematic approach in which the API/ANGA data were collected and vetted by natural gas experts is an improvement over the *ad hoc* way in which EPA collected some of their data. This study indicates that EPA should reconsider their inventory methodologies for unconventional natural gas production particularly in light of more comprehensive and emerging data from the industry. ANGA and API members look forward to working with the agency to continue to educate and evaluate the latest data as it develops about the new and fast-changing area of unconventional well operations.

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Appendix A. API/ANGA Survey Forms

The following provides the survey forms used to gather data presented in this report.

FIGURE A-1. SURVEY INSTRUCTIONS

The attached worksheets request data to support both the API/ANGA Natural Gas Life Cycle Analysis Project, as well as updates to EPA's National GHG Inventory. Portions of this information are consistent with data required for Subpart W, in which case data collected for Subpart W can be provided.

EPA's most recent national inventory significantly increased the emission estimates for gas well completions and workovers with hydraulic fracturing and gas well liquids unloading. These increases prompted public criticism of unconventional natural gas production.
While acknowledging their unconventional well workover activity factors were based on limited data, EPA has also indicated that activity data for centrifugal compressor wet seals and pneumatic devices used in the national inventory is lacking.

API and ANGA are requesting this information to develop more rigorous emission estimates for these important emission sources. This spreadsheet primarily focuses on activity factor information. A second data request will be developed later this year to collect information to support improved emission factors.

Company confidential information will be protected.

Please do not send information responsive to the data request to API or ANGA. Neither API nor ANGA will review member data sent in response to this request. Any submission to API or ANGA that appears to contain information responsive to EPA's data request will be returned to the sender unopened.

Please send the completed spreadsheets to:
Terri_Shires@URScorp.com
Questions may be directed to the same address, or by phone: 512-419-5466

Respondents are asked to complete as much information as possible. Some worksheets request data in varying levels of detail, with guidance on the minimum level of information needed. Some worksheets request data for more than one year or more than one production basin, if available. Gaps in the data are OK if the information is not available.

Additional instructions and guidance are provided on each worksheet.

Schedule:

Data indicated in blue font and shading is requested by August 15

Data indicated in green font is requested by September 16, if this level of information available. This more detailed information will help develop more rigorous emissions estimates for these sources.

FIGURE A-2. GAS WELL SURVEY DATA

Table 1. Producing Gas Wells - Activity Data

Please provide the following information for gas producing wells

		Conventional Wells	Unconventional Wells			Year	Geographic Area Represented	Comments
			Shale	Coal-bed Methane	Tight			
A	Total # of Operating Gas wells							Total of rows A(1) and A(2)
A(1)	*# Wells w/out hydraulic fracturing (anytime in their history)*							
A(2)	*# Wells with hydraulic fracturing (any time in their history)*							If counts are not available by vertical and horizontal, please complete this row
A(2)(a)	*# Vertical wells with hydraulic fracturing (anytime in their history)*							Please provide this level of detail, if available for wells with hydraulic fracturing
A(2)(b)	*# Horizontal wells with hydraulic fracturing (anytime in their history)*							
B	# Gas well Completions							Total of rows B(1), B(2) and B(3)
B(1)	*# Completions for Vertical wells with hydraulic fracturing*							
B(2)	*# Completions for Horizontal wells with hydraulic fracturing*							Please provide this level of detail, if available
B(3)	*# Completions for wells without hydraulic fracturing*							
C	# Gas well Workovers with hydraulic fracturing (refracs)							Total of rows C(1) and C(2)
C(1)	*# Workovers for Vertical wells with hydraulic fracturing*							
C(2)	*# Workovers for Horizontal wells with hydraulic fracturing*							Please provide this level of detail, if available
C(3)	*# Workovers for wells without hydraulic fracturing*							

Guidance:
2010 data is preferred, with U.S. geographic coverage as broad as possible.

Please duplicate the table to provide data for additional calendar years (if available) or additional geographic areas (if needed).

Note that some of this information overlaps with the data requested under the "Re-frac" worksheet.

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information and have a longer response time

Geographic area:

Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

FIGURE A-3. GAS WELL WORKOVER SURVEY DATA

Table 2. Gas Well Workover Activity Data: Frequency of Re-fractures

	Year	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
A	*Geographic area*										
B	*Number of Unconventional Operating Gas Wells*										
C	*Number of Fracture Stimulation Wells Completed each year (New Completions)*										
D	*Number of Fracture Stimulation Jobs conducted each year on Previously Fracture Stimulated Wells (i.e., # of Workovers or re-fracs)*										

Guidance

Please provide information that you have available.

Please provide data that are available for any or all of the years listed. Gaps in the data are OK.

Copy the table to provide data for additional geographic areas

A Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins)

B Provide the number of Unconventional Operating Wells. This refers to wells located on shale, coal-bed Methane, and Tight Formations reservoirs. Unconventional reservoirs are reservoirs that require fracture stimulation to economically produce.

C Provide the number of new completions conducted in the year. This may be the same value provided in the "Well data" worksheet, Item B.

D Provide the number of re-fractures (workovers). A re-frac or workover is defined as a re-completion to a different zone in an existing well or re-stimulation of the same zone in an existing well. This may be the same value provided in the "Well data" worksheet, Item C. Hydraulic Fracture jobs conducted more than 30 days from the end of one stimulation job to the beginning of another stimulation job in the same well-bore is a new re-frac.

Notes

The EPA uses an assumption that 10% of wells are refractured each year to determine the number of re-frac's per year and then multiplies this by 9.175 MMSCF methane per re-frac to arrive at their inventory for this particular category.

For the year reported in Table 1, this table requests redundant information. The purpose of this table is to collect refracture information over a ten-year time period to provide a better estimate to EPA's assumption that 10% of wells are refractured each year.

FIGURE A-4. GAS WELL LIQUIDS UNLOADING SURVEY DATA

Table 3. Gas Well Venting for Liquids Unloading (Well Clean-ups)

A Please indicate if the information provided in Table 3 follows the Subpart W methodologies (yes or no)

		Conventional	Unconventional	Total	Comments
B	Geographic Area				
C	Time Period - Months				
D	Number of Operated Gas Wells Represented by the information provided				Unconventional wells are: Shale, coal-bed methane, and tight formation (sand, carbonate, etc.) that must be fracture stimulated to produce economic quantities of gas
E	Number of Gas Wells with Plunger Lift Installed				
F	Number of Gas Wells with Other Artificial Lift (Beam Pump; ESP; etc.)				
G	Number of Gas Wells Vented to the atmosphere for Liquids Unloading				EPA assumes that 41.3% of conventional gas wells (437,800) are vented for liquids unloading
H	Total number of Gas Well Vents for Time Period				EPA assumes that each venting well vents 38.7 times per year
I	Average Venting Time per Vent				EPA assumes that each venting event is 3 hours duration
J	*Number of Wells with Plunger Lifts that vent to the atmosphere*				This is a sub-category of data item #5. Please indicate here the number of wells that vent to the atmosphere
K	*Total Count of Gas Well Vents for Time Period - w/plunger*				
L	*Total Count of Gas Well Vents for Time Period - w-o/plunger*				
M	*Average Venting Time - w/plunger*				Hours per Vent - fractional hours if appropriate
N	*Average Venting Time - w-o/plunger*				Hours per Vent - fractional hours if appropriate
O	*Average Daily Production of Venting Gas Wells*				mcf/day
P	*Average Depth of Venting Wells*				feet
Q	*Average Casing Diameter of Venting Gas Wells*				inches
R	*Average Tubing Diameter of Venting Gas Wells w/plunger Lift*				inches
S	*Average Surface Pressure - Venting Gas Wells*				psig

Guidance:

This table represents data from a sampling of wells (as opposed to data for all of your wells).

If information is not available by conventional or unconventional wells, just provide data in the "total" column.

A If you do not have data based on Subpart W, please indicate this in data item A by typing yes or no in the shaded box

Copy the table to provide data for additional geographic areas

Please provide information that you have available.

Blue rows are the minimum level of detail needed

Green rows provide more detailed information

B Geographic Area: Please indicate whether the information provided is for all of your operations in the U.S., or just a sub-part (single basin or multiple basins).

C Time period: Indicate the number of months represented by the information provided. Ideally this is based on some portion of 2011 data collected for Subpart W reporting.

J This data line is a sub-category if data item E. From the difference between these two items, we are trying to determine the fraction of plunger equipped wells that do not vent.

K,L Please enter the number of liquids unloading events where gas is released to the atmosphere.

Notes:

Many companies have likely been tracking well venting for liquids unloading for several months due to Subpart W. API is soliciting information from members to correct/confirm EPA's assumptions regarding well un-loading. If you do not have the wells split out into Conventional and Unconventional categories then simply report the total counts and information in the Conventional categories.

FIGURE A-5. OTHER SURVEY DATA

Table 4. Other Activity Data

A

Centrifugal Compressors			
	Production/ gathering	Processing	
Year			2010 data is preferred, but available information from any recent year is OK
Number of Centrifugal Compressors			Include both engine/turbine driven and electric driven
Number with Dry Seals			
Number with Wet Seals			

B

Pneumatic Devices (Controllers)				
	Well Sites	Gathering/ Compressor Sites	Gas Processing Plants	
Year				2010 data is preferred, but available information from any recent year is OK
Number of Sites/Plants Covered				The total number of wells sites, gathering compressor sites, of gas processing plants represented by the inventory of devices below
Number of Low Bleed				EPA defines low bleed as <6 scfh
Number of High Bleed				EPA defines high bleed as >6 scfh
Number of Intermittent				

Guidance

For pneumatic devices: Do not include counts of devices operated on compressed air. Designate pneumatic devices between "high bleed", "low bleed", or "intermittent" following the approach your company is using for Subpart W reporting.

Appendix B. ANGA/API Well Survey Information

Responses from the API/ANGA survey covered more than 60,000 wells and provided data on:

- # of gas wells without hydraulic fracturing (anytime in their history)
- # of gas wells with hydraulic fracturing (any time in their history);
  - # of vertical gas wells with hydraulic fracturing (anytime in their history);
  - # of horizontal gas wells with hydraulic fracturing (anytime in their history);
- # of completions for vertical gas wells with hydraulic fracturing;
- # of completions for horizontal gas wells with hydraulic fracturing;
- # of completions for gas wells without hydraulic fracturing;
- # of workovers for vertical wells with hydraulic fracturing;
- # of workovers for horizontal wells with hydraulic fracturing; and
- # of workovers for wells without hydraulic fracturing.

Table B-1 summarizes the well data collected by the ANGA/API survey and presents its distribution by formation type and region. The regional distribution follows the National Energy Modeling System (NEMS) regions defined by the EIA. The data are compared to EPA's national well counts classified by type as provided in the August 2011 database file (EPA, 2011d).

TABLE B-1. API/ANGA SURVEY – SUMMARY OF GAS WELL COUNTS BY TYPE AND NEMS REGION*

NEMS Region	Conventional Wells	Shale	Coal-bed Methane	Tight	Unspecified
Northeast	12,144	3,541	9	3,874	2,563
Gulf Coast	2,870	1,990	-	7,968	1,521
Mid-Continent	9,081	2,333	-	3,747	5,579
Southwest	646	1,208	-	726	2,326
Rocky Mountain	3,707	366	5,458	18,053	11
West Coast	-	-	-	-	-
Unspecified					1,307
Survey TOTAL	28,448	9,438	5,467	34,368	13,307
% of EPA 2010 Well Counts (from database file)	14.2%	30.1%	11.5%	45.6%	
Overall Survey Total	91,028				
EPA Well Counts (2010, from database file)	200,921	31,381	47,371	75,409	
	56.6%	8.8%	13.3%	21.2%	
	355,082				
EPA National Inventory (2010)	484,795				
EIA National Well Count (2010)	487,627				

* ANGA/API survey data represents well counts current for calendar year 2010 or the first half of 2011.

As shown in Table B-1, data from the API/ANGA survey represent approximately 26% of the national gas wells reported by EPA's database (or 18.7% of the EIA well count data). This includes almost 46% of all tight gas wells and 30% of shale gas wells. This may indicate that the ANGA/API information has an uneven representation of unconventional gas wells, and in particular shale and tight gas wells, but it also appears that EPA's data may mis-categorize these types of wells. For example, the EPA/HPDI data set contains few wells from Pennsylvania and West Virginia while the API/ANGA survey includes 9,422 wells from that area (AAPG 160A).

Table B-2 summarizes additional details on the natural gas wells information collected through the second data collection effort by the ANGA/API survey which covered 60,710 wells.

TABLE B-2. ANGA/API SURVEY – ADDITIONAL DETAILS ON GAS WELL COUNTS*

	# Wells w/out hydraulic fracturing (anytime in their history)	# Wells with hydraulic fracturing (any time in their history)		
		Total	# Vertical wells	# Horizontal wells
TOTAL Conventional	1,498	16,678	14,844	1,834
TOTAL Coal Bed Methane	42	3,475	3,424	42
TOTAL Shale	1,931	9,084	2,012	7,072
TOTAL Tight	122	27,880	24,048	3,835
TOTAL OVERALL	**3,593**	**57,117**	**44,325**	**12,783**

* API/ANGA survey data represents well counts current for calendar year 2010 or the first half of 2011.

Additional information on natural gas wells with and without hydraulic fracturing was provided for approximately two-thirds (60,710 natural gas wells) of the total well data collected by the ANGA/API survey. For this subset of the well data, 94% of the gas wells have been hydraulically fractured at some point in their operating history, including almost 92% of the conventional wells. EPA's 2010 national inventory reported 50,434 gas wells with hydraulic fracturing. This is very similar to the number of unconventional gas wells that EPA reported in the 2009 national inventory. ***Based on the API/ANGA survey results, it appears that EPA has underestimated the number of gas wells with hydraulic fracturing.***

Of the ANGA/API survey responses for wells that have been hydraulically fractured, most (77.6%) are vertical wells. Vertical wells are predominately conventional gas wells, coal-bed methane and tight gas wells; while the majority of shale gas wells are horizontal. EPA does not currently distinguish between vertical and horizontal gas wells.

A Short Note About EPA and EIA's Well Counts

There is a discrepancy of over 132,000 natural gas wells between the EPA database information (EPA, 2011d) and the EIA national gas well counts (EIA, 2012), and a difference of almost 130,000 gas wells between the two EPA data sources (EPA, 2011d and EPA, 2012). This difference needs to be understood since ultimately both the IHS (EIA) and HPDI (EPA) data originate from the same state-level sources of information.

The EIA provides a gas well count of 487,627 for 2010 based on Form EIA-895A[7], the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals

[7] Form EIA-895, Annual Quantity And Value Of Natural Gas Production Report; http://www.eia.gov/survey/form/eia_895/form.pdf

Management Service) data, and World Oil Magazine (EIA, 2010). However, the EIA does not classify gas wells by conventional and unconventional, or by formation types, precluding more detailed comparison against the EIA data. For some parameters the classifications were based on qualitative descriptions of the formations' physical properties (e.g. permeability) rather than on actual measurements (i.e. permeability data in millidarcy readings).[8]

EPA provides a similar well count in the 2010 national inventory: 434,361 non-associated gas wells + 50,434 gas wells with hydraulic fracturing, resulting in a total of 484,795 gas wells (EPA, 2012). Further classification of gas wells or description on what constitutes a "non-associated" gas well versus a "gas well with hydraulic fracturing" is not provided in EPA's national inventory.

Small differences in the HPDI and IHS original data may arise from definitional differences as HPDI and IHS compile the raw data. In addition, each state may have a different interpretation of well definitions of gas versus oil wells that introduces differences among states for the wells reported. EPA had indicated in discussions with the API/ANGA group that their database well count information may not include all of the wells in the Marcellus basin. EIA indicates 44,500 gas wells in Pennsylvania in 2010. However, even in accounting for these wells, there is still a large difference (almost 88,000 wells) between EPA's total gas well number from their database source and EIA's well data.

Nevertheless, these discrepancies among the well counts need to be understood since these data all originate from the same state-level sources of information. Differences could arise, for example, from different interpretations of well definitions.

Since the EIA data is the *de facto* benchmark in the energy industry, the difference between the EIA and EPA well count data needs to be understood before any meaningful conclusions can be made from the EPA data.

Since EPA's well count from HPDI was much lower than the EIA, this report does not attempt to come up with a national gas well count but chose to use the 355,082 number from the EPA HPDI database because it was the only available database which parsed the wells into conventional and unconventional categories (EPA, 2011d).

[8] Information provided by Don Robinson of ICF (EPA's contractor).

Appendix C. Emission Estimates for Gas Well Liquids Unloading

Tables C-1 through C-4 summarize the liquids unloading emissions data collected through the API/ANGA survey and the resulting emission estimates. The emission factors reported in Table 4 are based on a regional weighted average of the conventional and unconventional gas wells, with and without plunger lifts. This provided a consistent comparison against the EPA emission factors which are reported only on a regional basis and do not differentiate between conventional and unconventional wells or wells with and without plunger lifts.

TABLE C-1. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast		Gulf Coast		Mid-Continent		Southwest
# venting gas wells	190	916	12	6	1	38	220
# gas well vents	4,335	39,668	144	60	1	2,444	880
Average casing diameter, inches	5	4.5	5.5	3.65	4.83	4	5.5
Average well depth, feet	3,375	3,448	10,000	19,334	7,033	4,269	8,000
Average surface pressure, psig (for venting wells)	85	50	Applied average 122	224	25.5	60.8	100
Average venting time, hours	1	2	1	2.5	.25	4.95	1
Average gas flow rate, Mscfd	2,861	7,388.5	300	664	58.43	84	100
Total emissions, scf gas/yr	11,503,329	51,547,287	1,961,463	1,322,380	1,548	3,769,194	7,879,520
Emissions per well, scfy gas/well	60,544	56,274	163,455	220,397	1,548	99,189	35,816

TABLE C-2. LIQUIDS UNLOADING FOR CONVENTIONAL GAS WELLS WITH PLUNGER LIFTS

NEMS Region	Northeast		Mid-Continent		
# venting gas wells	33	109	164	2	10
# gas well vents	1,272	4,217	489,912	23	7,300
Average tubing diameter, inches	2	2.375	1.995	2	2.375
Average well depth, feet	3,375	3,448	4,269	7,033	9,500
Average surface pressure, psig (for venting wells)	85	50	60.8	25.5	500
Average venting time, hours	1	0.3	0.067	0.75	0.08
Average gas flow rate, Mscfd	2,861	7,388.5	84	58.43	30
Total emissions, scf gas/yr	599,664	1,517,294	187,255,825	6,713	72,367,809
Emissions per well, scfy gas/well	18,172	13,920	1,141,804	3,357	7,236,781

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS

NEMS Region	Northeast	Gulf Coast					
# venting gas wells	337	6	14	8	27	11	15
# gas well vents	27,720	6	14	104	207	572	15
Average casing diameter, inches	4.5	5.5	5.5	5.5	4.5	5.5	10.75
Average well depth, feet	4,845	6,000	8,500	11,000	9,000	13,752	16,000
Average surface pressure, psig (for venting wells)	121.6	400	3,200	200	50	450	1,671
Average venting time, hours	1.3638	3	4	1	5.3	2	2
Average gas flow rate, Mscfd	26	200	13,000	25	130	353	8,500
Total emissions, scf gas/yr	122,362,610	177,839	5,887,104	2,560,844	722,663	39,633,526	17,501,885
Emissions per well, scfy gas/well	363,094	29,640	420,507	320,106	26,765	3,603,048	1,166,792

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Gulf Coast				Mid-Continent			
# venting gas wells	146	2	10	40	177	3	136	215
# gas well vents	146	12	120	40	400	7.2	391.2	2,580
Average casing diameter, inches	4.5	5.5	5.5	8.625	5.5	4.92	5.02	5.5
Average well depth, feet	8,500	11,647	11,000	12,500	3,911	10,293	7,888	11,000
Average surface pressure, psig (for venting wells)	15	25	94	661	80	90.04	98.75	200
Average venting time, hours	0.6875	1.5	4	1	2.5	1.58	1.925	0.5
Average gas flow rate, Mscfd	99	83	92	6,500	250	727	875	100
Total emissions, scf gas/yr	139,473	40,837	1,400,265	9,096,858	1,416,389	77,333	2,874,991	63,528,630
Emissions per well, scfy gas/well	955	20,418	140,027	227,421	8,002	25,778	21,140	295,482

TABLE C-3. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITHOUT PLUNGER LIFTS, CONTINUED

NEMS Region	Southwest			Rocky Mountain		
# venting gas wells	228	6	3	113	2	28
# gas well vents	221	6	1	2,004	4	10,584
Average casing diameter, inches	9.625	5.5	5	4.038	4.7	4.5
Average well depth, feet	8,725	8,000	15,000	11,149	11,056	10,844
Average surface pressure, psig (for venting wells)	208	50	200	250	250	198
Average venting time, hours	1	0.5	6.67	1.616	0.75	3.18
Average gas flow rate, Mscfd	1,500	12	150	127	433	83
Total emissions, scf gas/yr	13,747,516	26,862	63,188	33,701,560	90,364	170,274,852
Emissions per well, scfy gas/well	60,296	4,477	21,063	298,244	45,182	6,081,245

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS

NEMS Region	Northeast			Gulf Coast				
# venting gas wells	308	103	5	3	2	22	59	5
# gas well vents	63,840	75,190	194	156	2	22	354	5
Average tubing diameter, inches	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Average well depth, feet	4,845	2,500	7,000	13,752	16,000	8,500	11,647	12,500
Average surface pressure, psig (for venting wells)	121.6	200	130	450	1,671	15	25	661
Average venting time, hours	0.2209	0.05	0.1	2	1	0.875	0.3	0.5
Average gas flow rate, Mscfd	26	15	628	353	8,500	99	83	6,500
Total emissions, scf gas/yr	78,496,300	78,461,940	368,444	2,036,862	288,681	7,401	215,123	86,220
Emissions per well, scfy gas/well	254,858	761,766	73,689	678,954	144,341	336	3,646	17,244

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Mid-Continent				Southwest
# venting gas wells	48	4	64	29	18
# gas well vents	155,742	9.6	170.4	348	25
Average tubing diameter, inches	2.375	3.88	4.11	2.4	1.995
Average well depth, feet	3,911	10,293	7,888	Applied average 9,521	8,725
Average surface pressure, psig (for venting wells)	80	90.04	98.75	74.69	208
Average venting time, hours	0.0833	2.99	2.6	0.5425	0.5
Average gas flow rate, Mscfd	250	727	875	Average applied 1,276.8	1500
Total emissions, scf gas/yr	101,698,021	124,984	906,144	529,679	66,812
Emissions per well, scfy gas/well	2,118,709	31,246	14,158	18,265	3,712

TABLE C-4. LIQUIDS UNLOADING FOR UNCONVENTIONAL GAS WELLS WITH PLUNGER LIFTS, CONTINUED

NEMS Region	Rocky Mountain				
# venting gas wells	247	23	296	19	793
# gas well vents	1,476	51.43	2,080	21,888	9,516
Average tubing diameter, inches	1.997	1.92	2.375	2.375	2.375
Average well depth, feet	11,149	11,164	11,056	10,844	7,400
Average surface pressure, psig (for venting wells)	250	290	250	198	150
Average venting time, hours	0.407	1.12	2.1	0.455	0.67
Average gas flow rate, Mscfd	127	454	433	83	46
Total emissions, scf gas/yr	6,070,440	238,833	12,027,460	98,082,094	22,045,130
Emissions per well, scfy gas/well	24,577	10,384	40,633	5,162,215	27,800

The calculated emissions shown in Tables C-1 through C-4 are based on applying Equation W-8 from 40 CFR 98 Subpart W to gas well liquid unloading without plunger lifts and Equation W-9 to gas well liquid unloading with plunger lifts. The equations and the terms are provided below.

98.233(f)(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W–8 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-8)}$$

Where:

$E_{s,n}$= Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3}= {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p= Casing internal diameter for each well, p, in inches.

WD_p= Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p= Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, p, in the sub-basin, in pounds per square inch absolute (psia).

V_p= Number of vents per year per well, p.

SFR_p= Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$= Hours that each well, p, was left open to the atmosphere during unloading, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

98.233(f)(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-9)}$$

Where:

$E_{s,n}$= Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3}= {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p= Tubing internal diameter for each well, p, in inches.

WD_p= Tubing depth to plunger bumper for each well, p, in feet.

SP_p= Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

V_p= Number of vents per year for each well, p.

SFR_p= Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$= Hours that each well, p, was left open to the atmosphere during each unloading, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$= If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements

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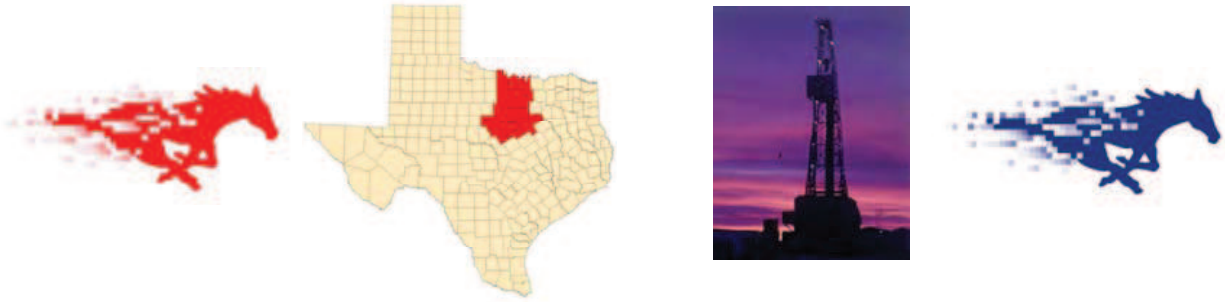


1.0 EXECUTIVE SUMMARY

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]

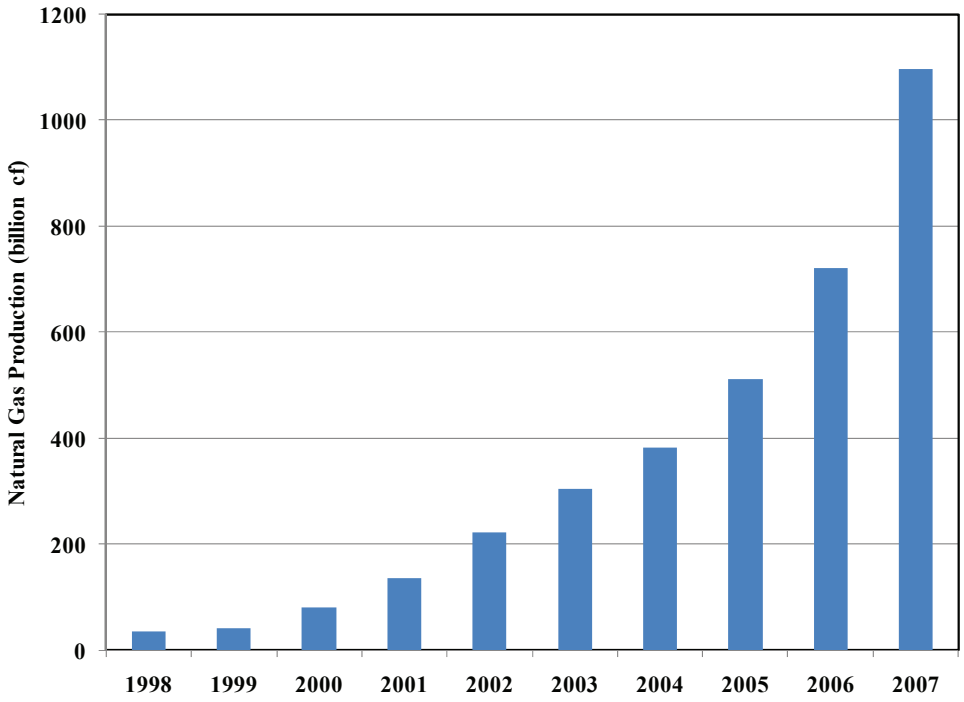


Figure 1. Barnett Shale Natural Gas Production, 1998-2007.

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+

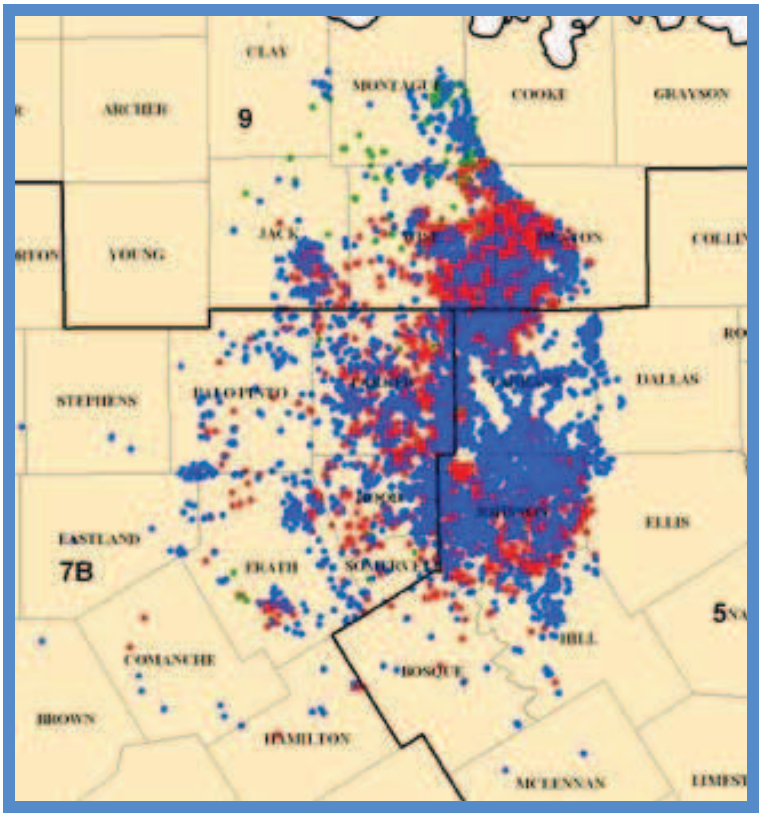
Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.[1]

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.

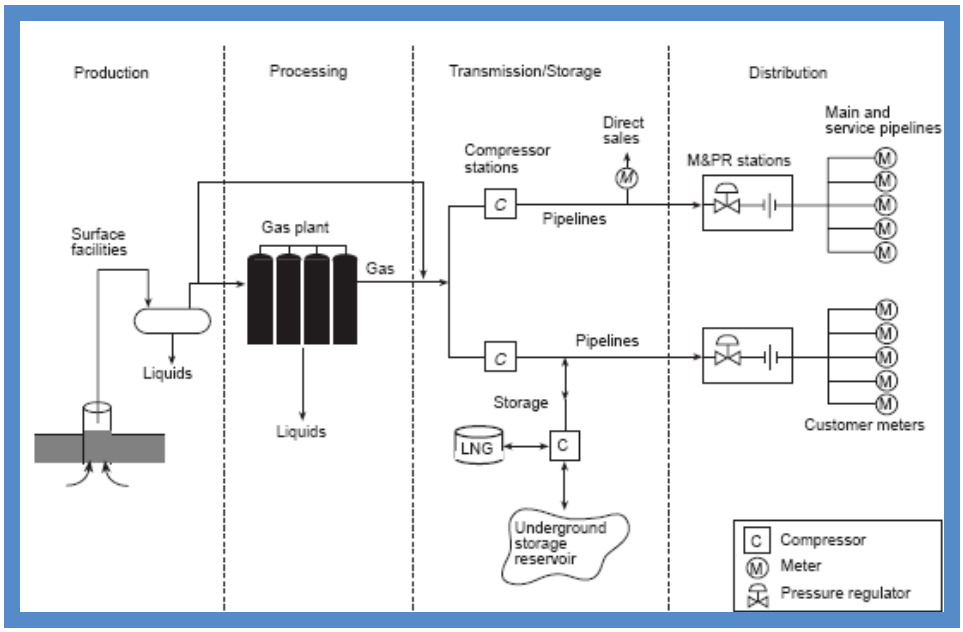


Figure 3. Major Units in The Natural Gas Industry From Wells to Customers. [3]

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,

$$M_{E,i} = 1.10E\text{-}06 * E_i * P_{cap} * F_{hl} \quad (1)$$

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,

$$M_{tr,i} = E_i * P_g / 2000 \qquad (5)$$

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 Pollutant (tpd)					2009 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 Pollutant (tpd)				2009 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.

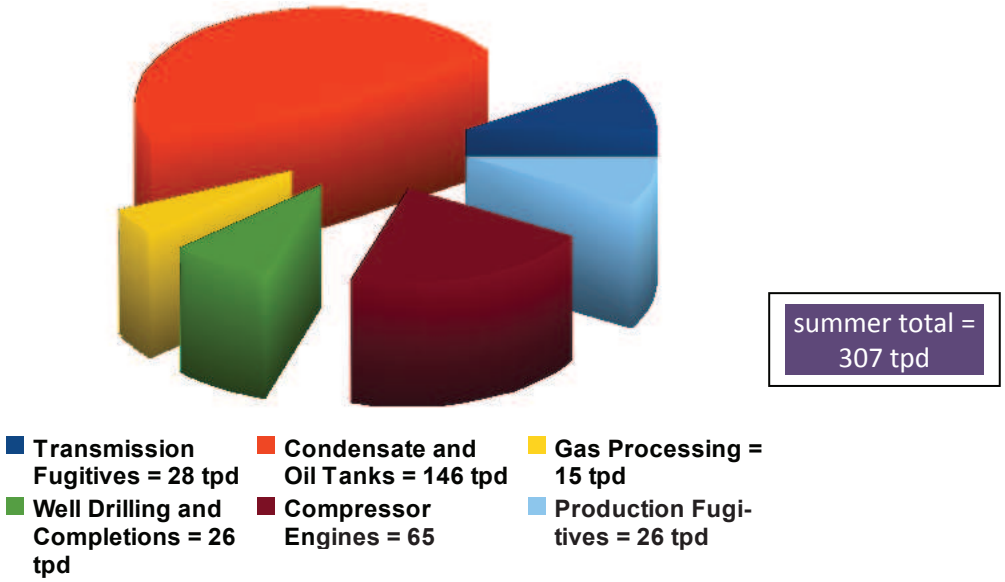
	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	**VOC**	**HAPs**	**CH4**	**CO2e**	**NOx**	**VOC**	**HAPs**	**CH4**	**CO2e**
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	19	0.39	4.5	95	0	30	0.60	7.0	149
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	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 Pollutant (tpd)					2009 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).

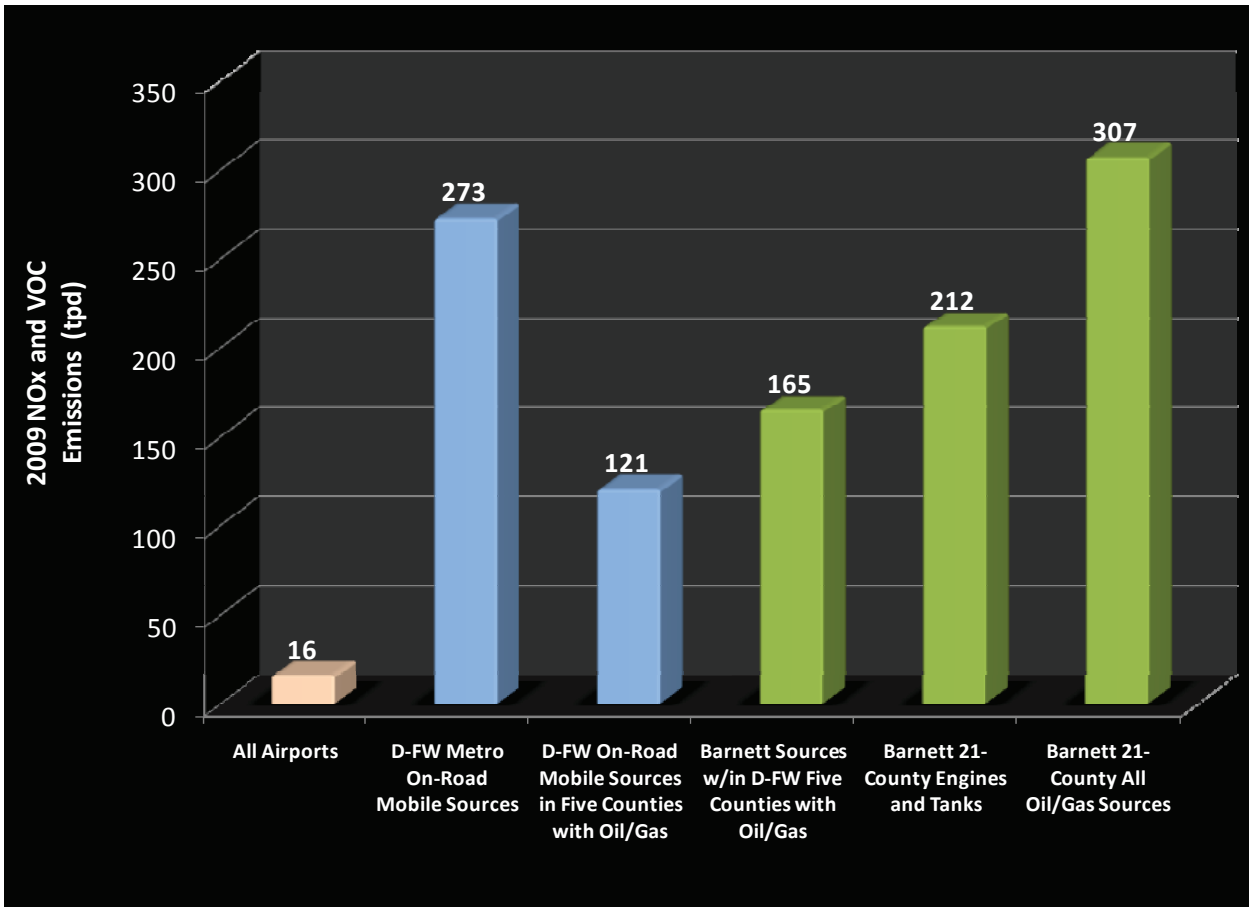
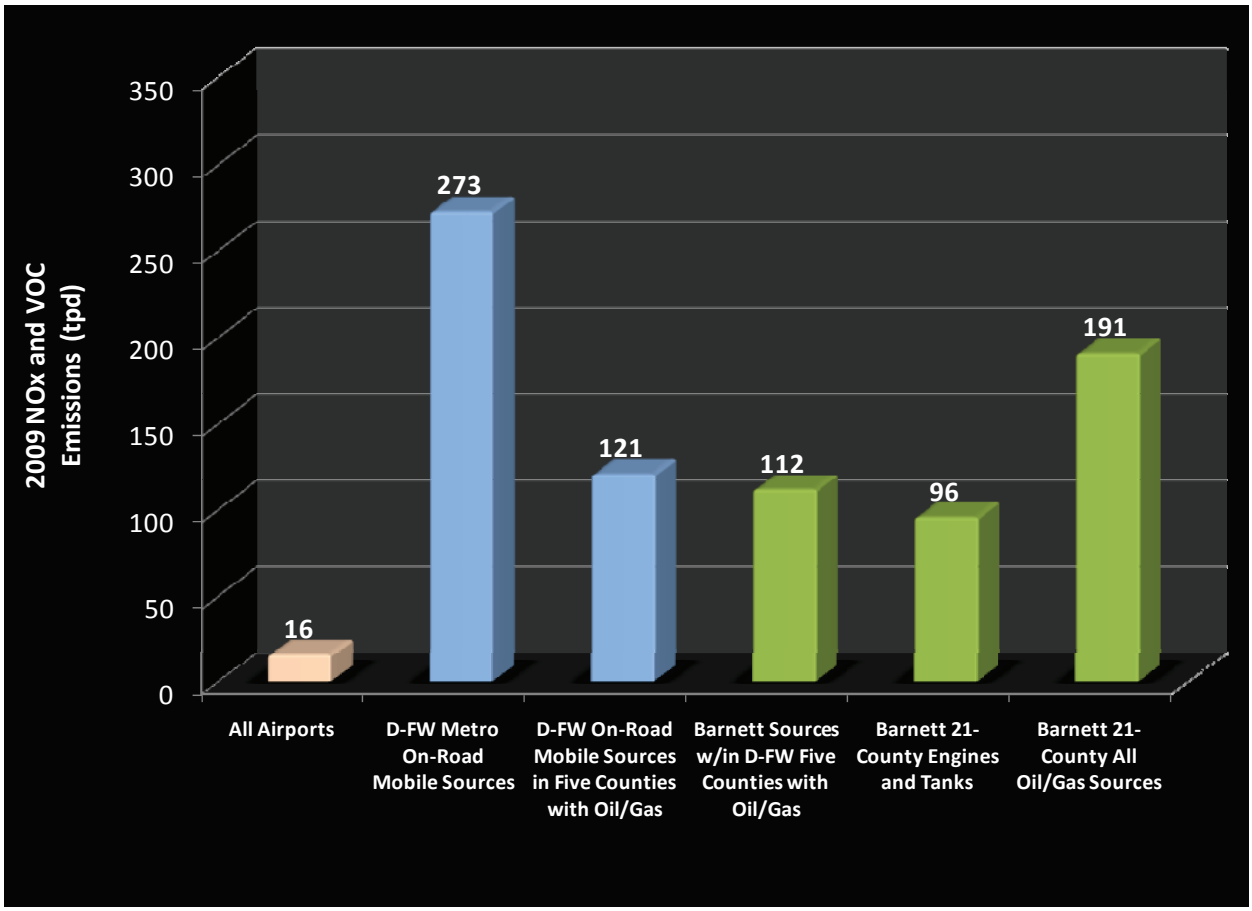


Figure 8. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Annual Average 2009 Emissions).



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:

A draft version of this report was prepared in September 2008 and distributed for review and comment to oil and gas producers, state and federal regulators, authors of some of the references used in this report, and others. The author appreciates the comments received by those reviewers and the time they took to provide feedback. For the purpose of full disclosure, the author notes that he was an employee with Radian International LLC working on projects for several gas industry clients, including the Gas Research Institute and gas pipeline companies, during the time that "Methane Emissions from the Natural Gas Industry" (Reference 15) was published. The authors of Reference 15 were also employees of Radian International LLC, working as contractors for the Gas Research Institute and the Environmental Protection Agency. The author of this study notes that he did not work on or participate in the GRI/EPA project performed by the other Radian International personnel.

Images on the cover page from the Texas Railroad Commission and the U.S. Department of Energy.

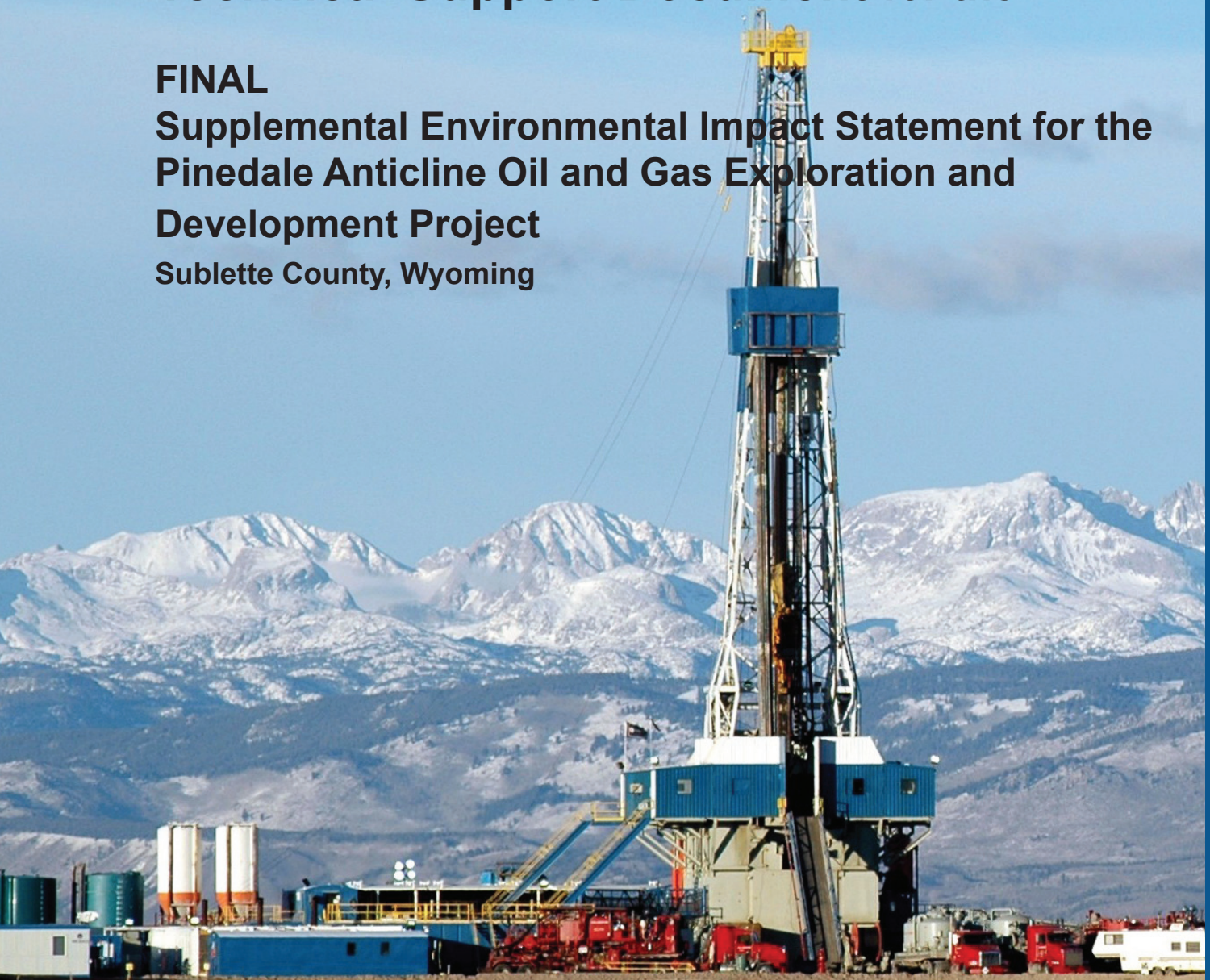
Some typos and spreadsheet errors fixed on 2/8/2009.

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



U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

June 2008

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 (Pad/Road Construction, Traffic, Completions, etc...)	NO_x	427.4	641.8	559.4
	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 (Expansion)	NO_x	301.7	301.7	301.7
	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 (Heaters, dehys, tanks, traffic, other production equipment, etc…)	NO_x	72.2	119.8	108.8
	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

Revised Regional Haze Plan
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.

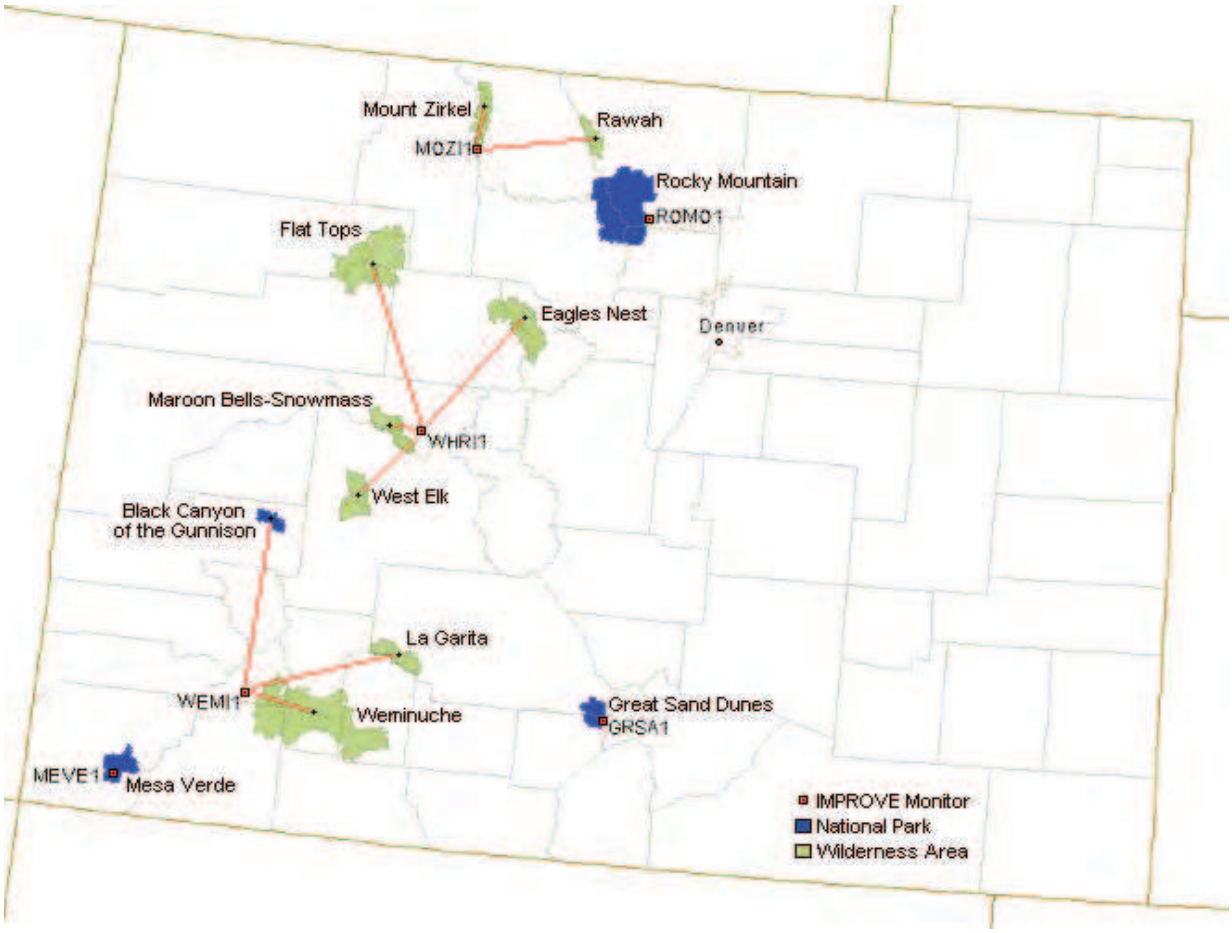
1.3 Description of Colorado's Class I Areas

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.

[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

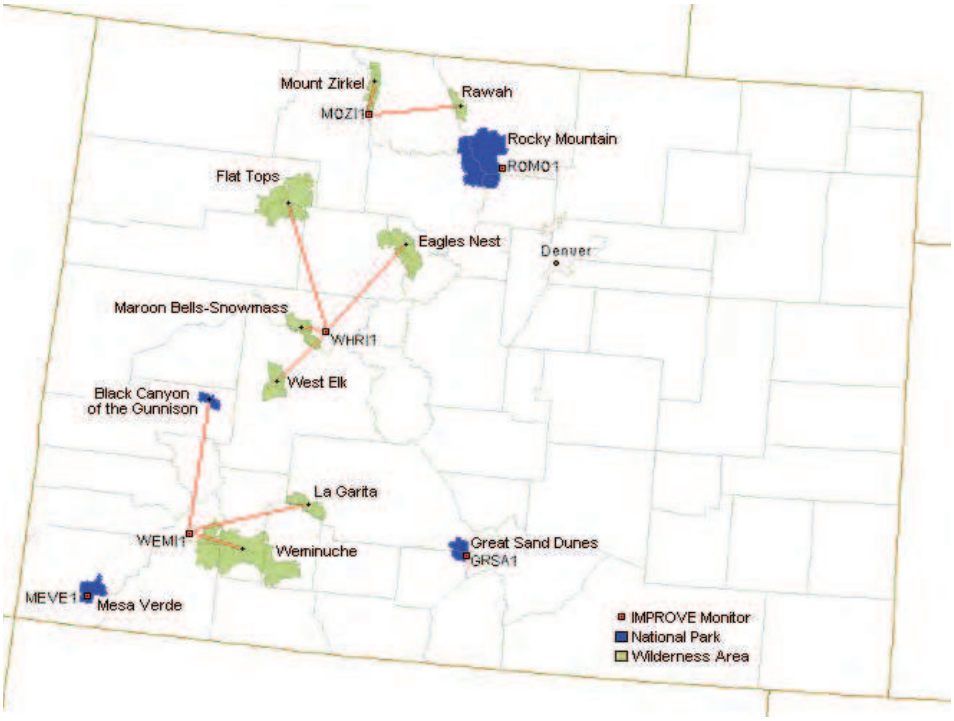


Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

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

[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.

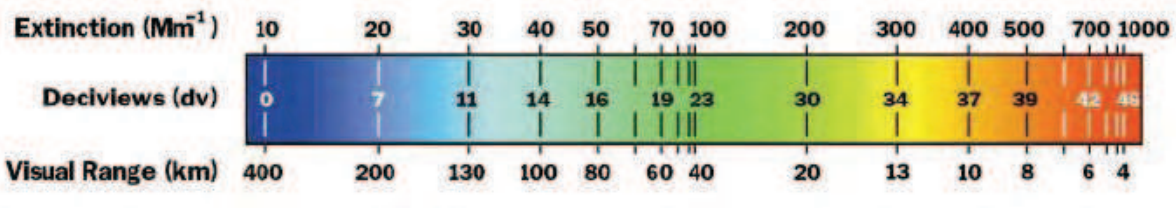
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

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)

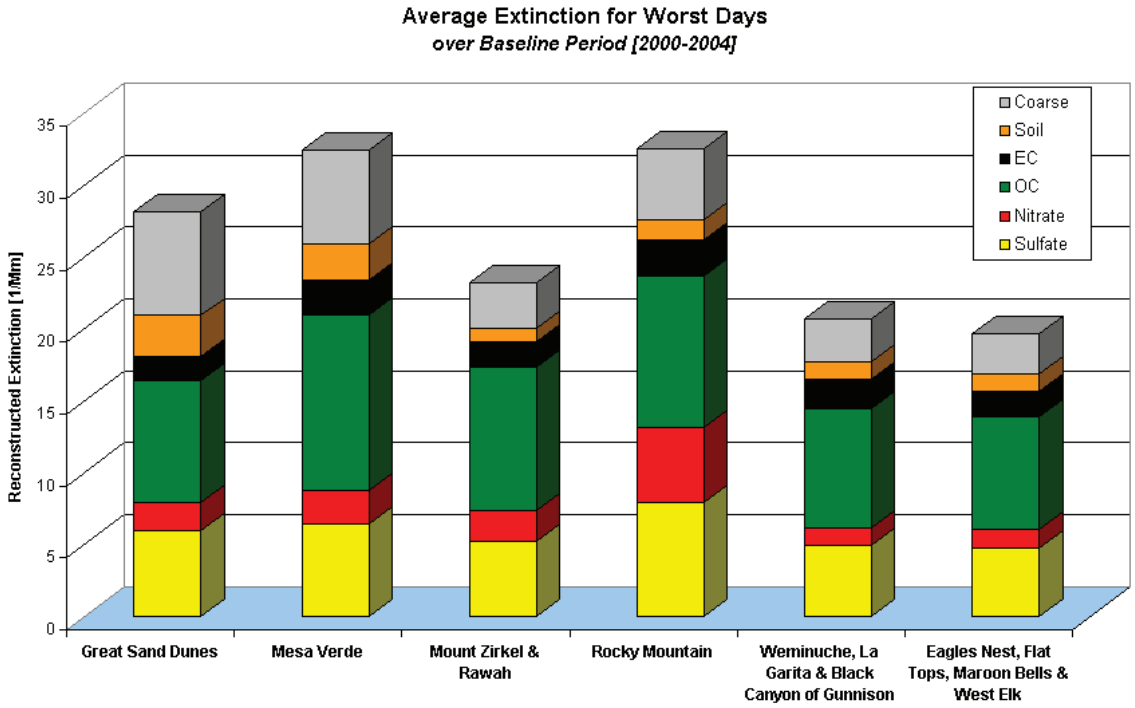
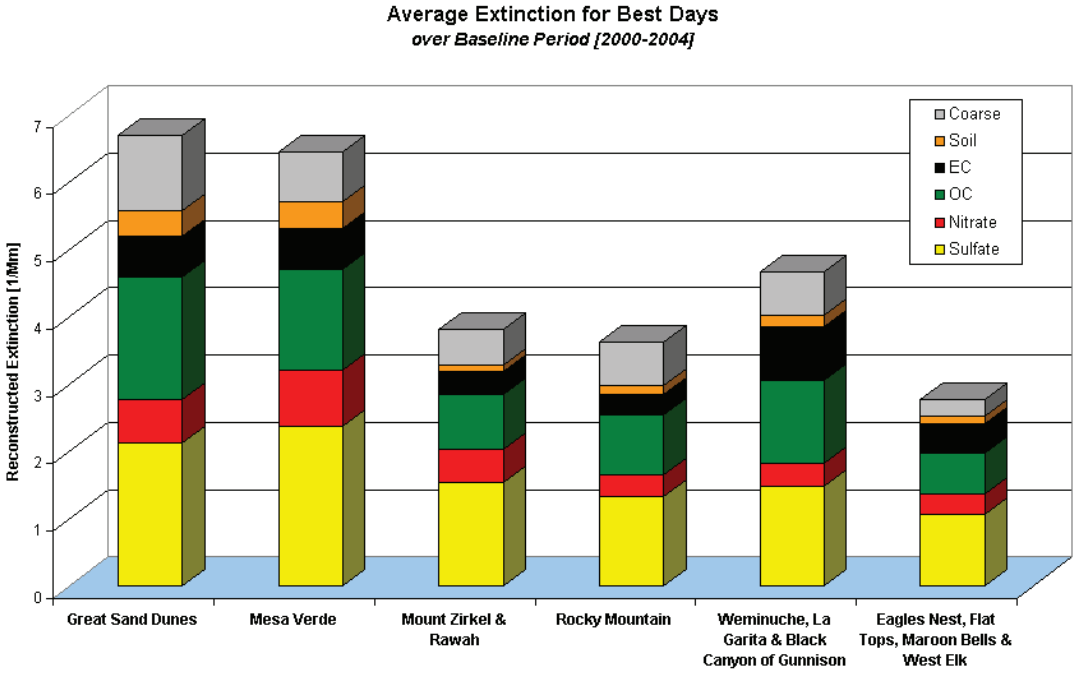


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



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 = [Baseline Condition - Natural Condition] / 60 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] x [14 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

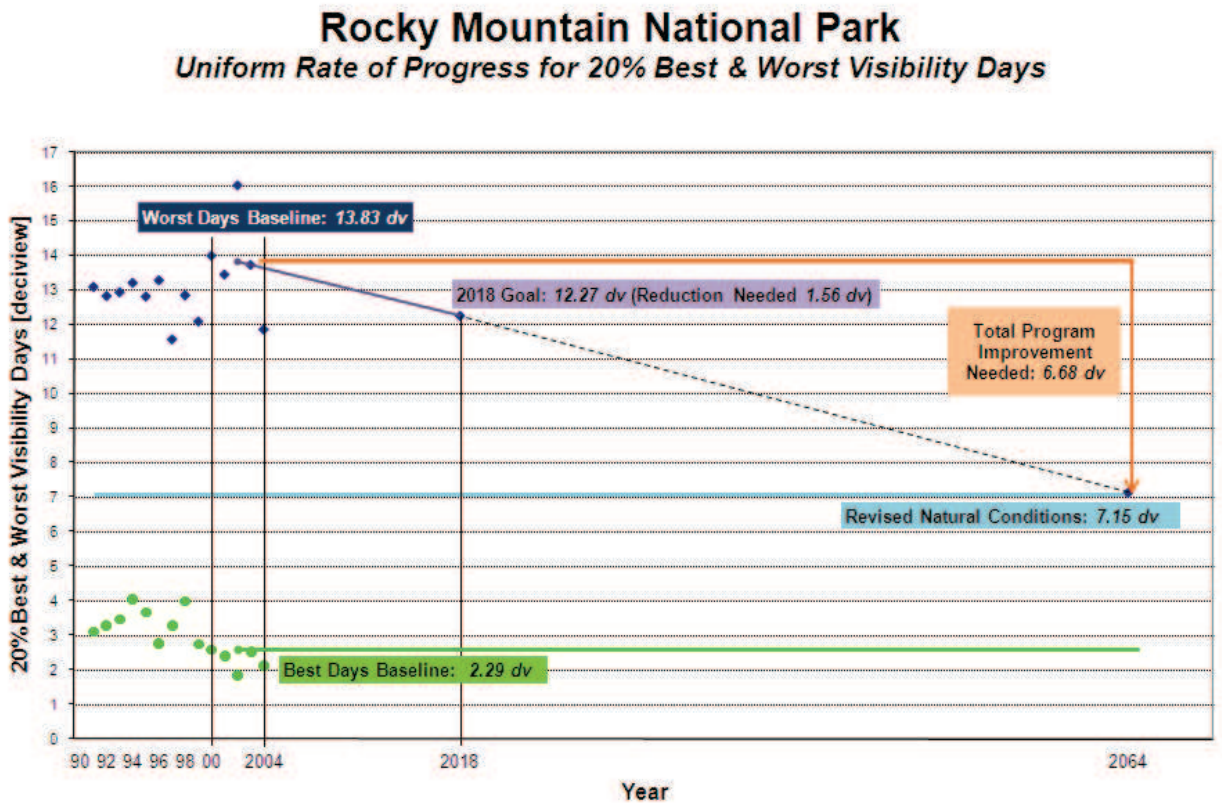
Baseline Summary of Best & Worst Days in Haze Index Metric

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			
Source Category	**Statewide SO2 Emissions**		
	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			
Source Category	**Statewide Soil (fine PM) Emissions**		
	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]*	PRP 2018(b) *[tons/year]*	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

[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" *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 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

[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

[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^{o}F) is significantly higher at the exit than a more typical preheater precalciner kiln (650^{o}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 98^{th} 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		Drake – Unit 6		Drake – Unit 7	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	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

[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.

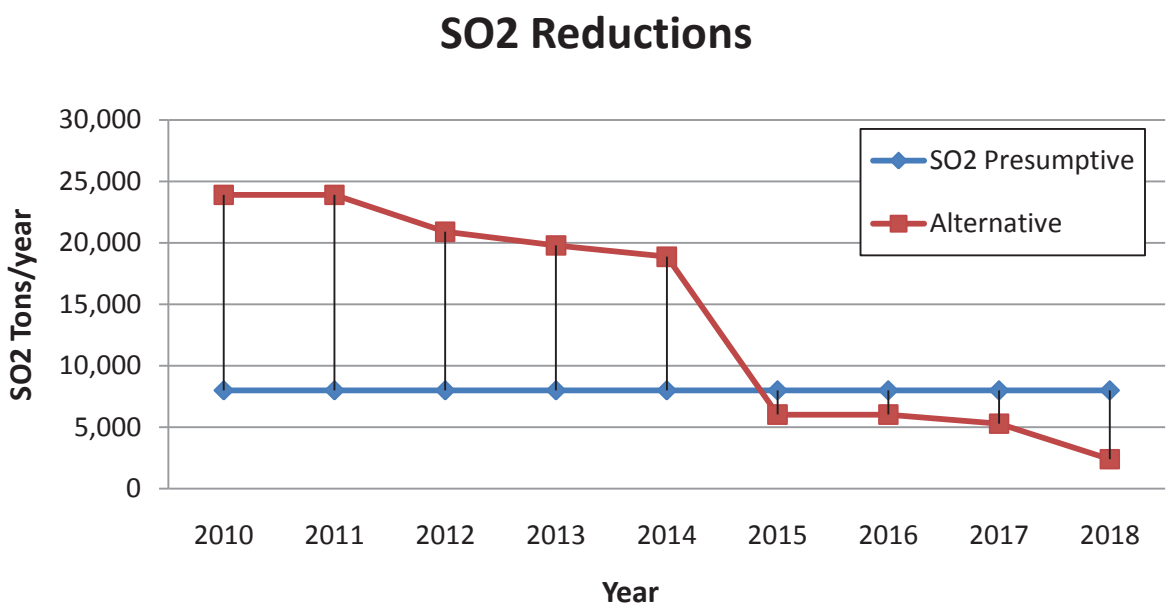
Table 6-7: SO2 Reductions Beyond Presumptive BART for PSCo Alternative

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



[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

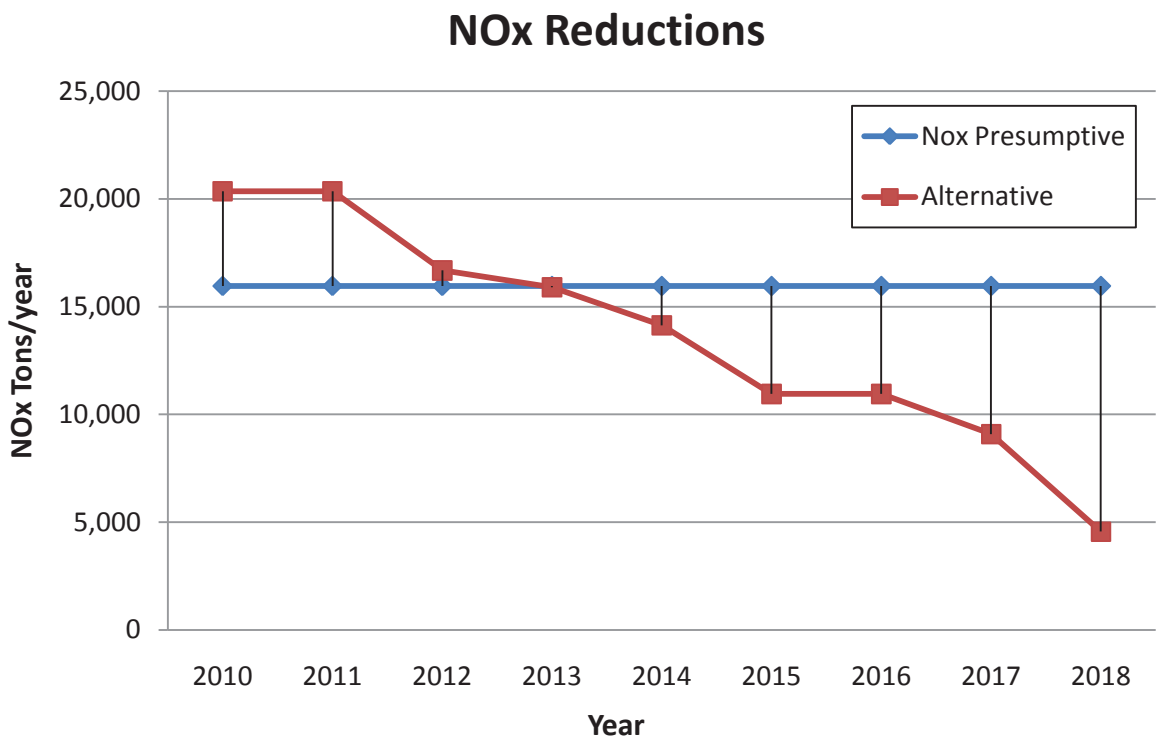
Facility	MMBtu Average 2006 to 2008	NOx TPY Average 2006 to 2008	NOx lb/MMBtu Standard	TPY NOx at Standard	TPY NOx Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00[20]	8.42%
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.

[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.

[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

[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".

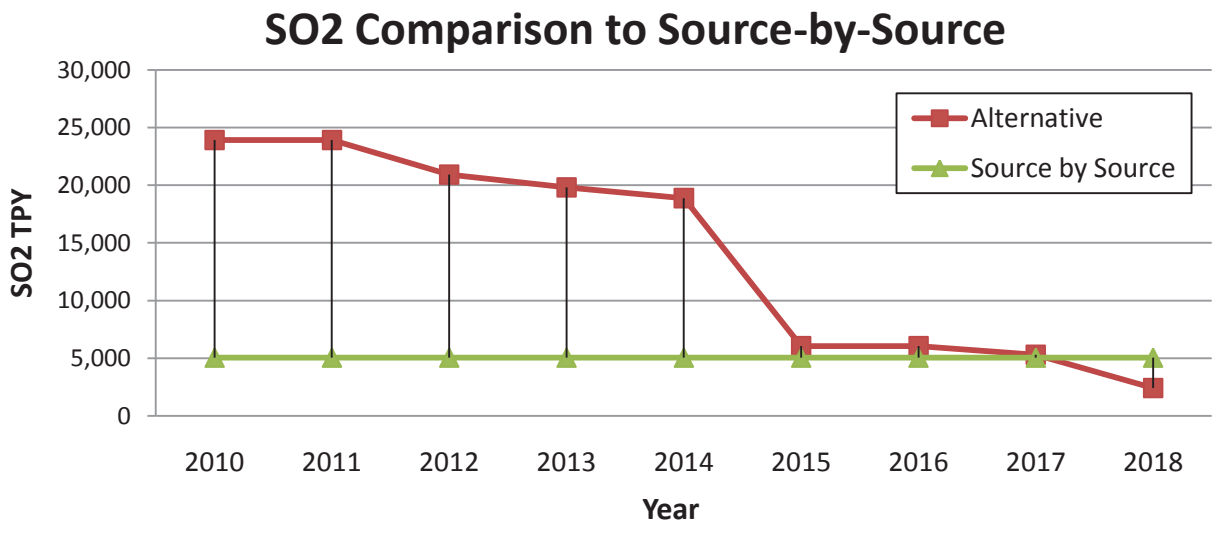
[27] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve 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



[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%

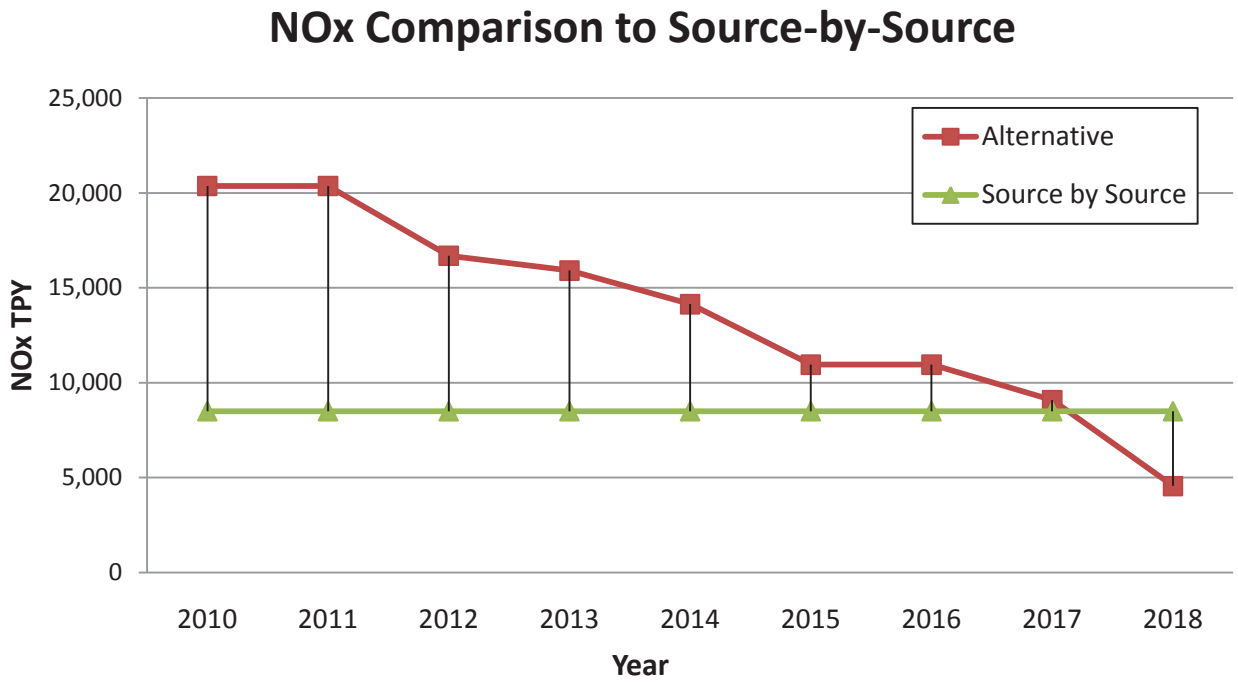
[30] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction 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.

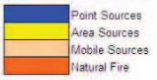
Figure 7-2 Summary of PSAT Modeling for 2018

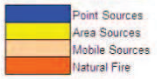
WRAP - PM Source Apportionment Technology (PSAT) Modeling Results

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





** 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

[37] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

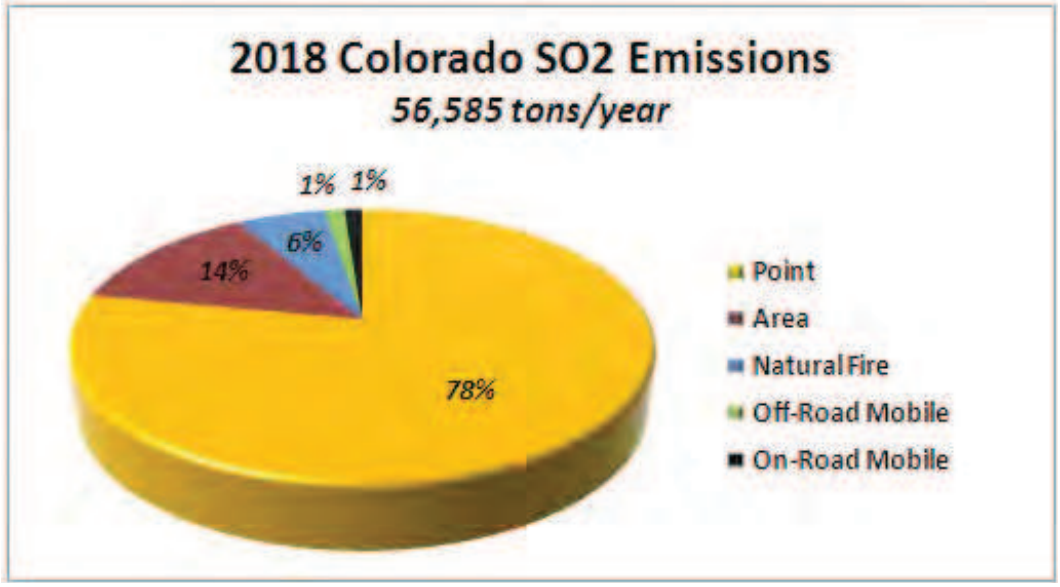
SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

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

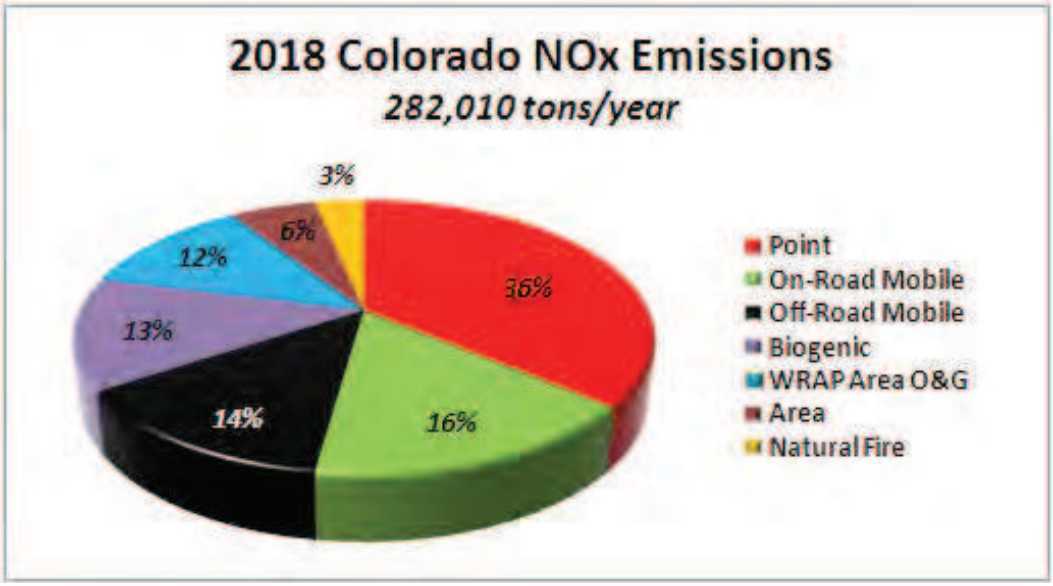


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content 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

[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

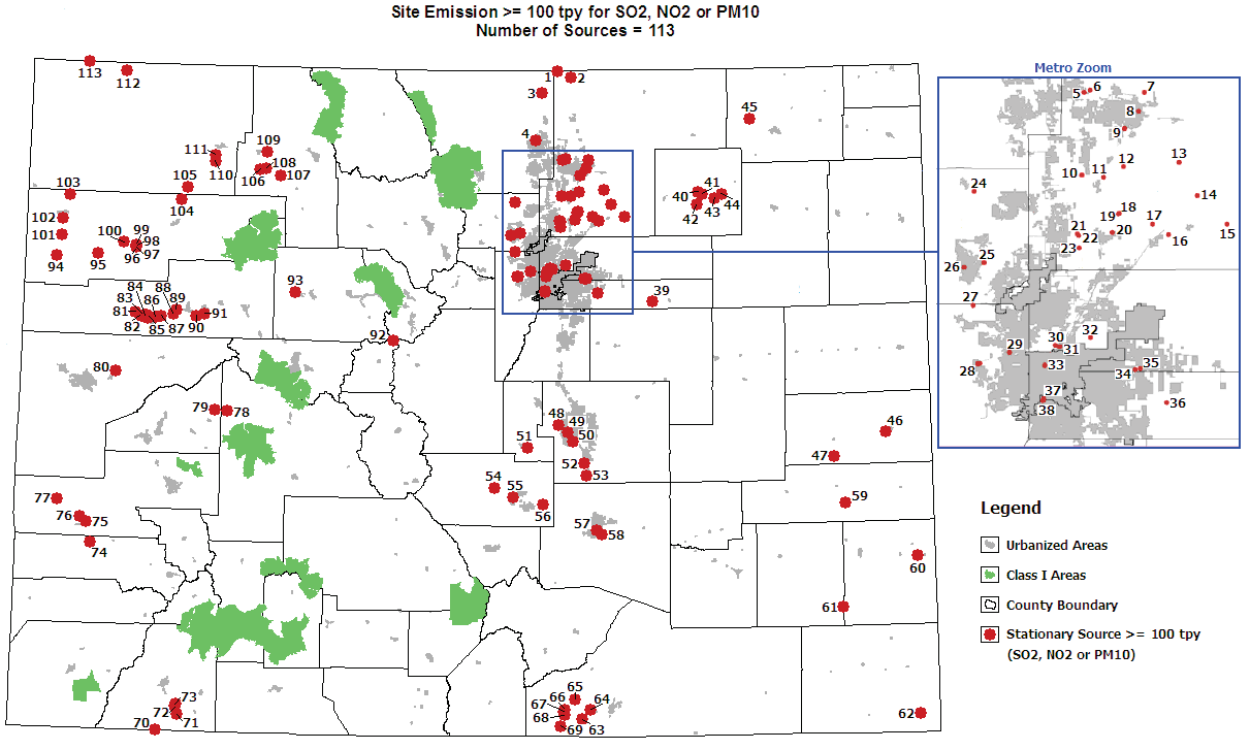


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

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.

[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

[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.

[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)	98^{th} 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;

[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
- 2010 RP: 12,624 tons/year

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

[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

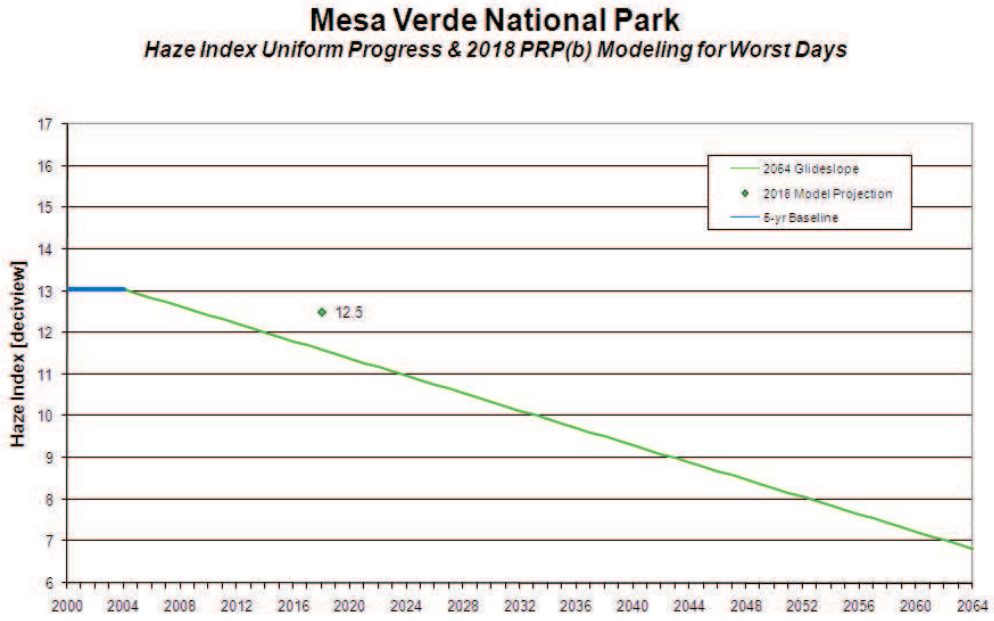
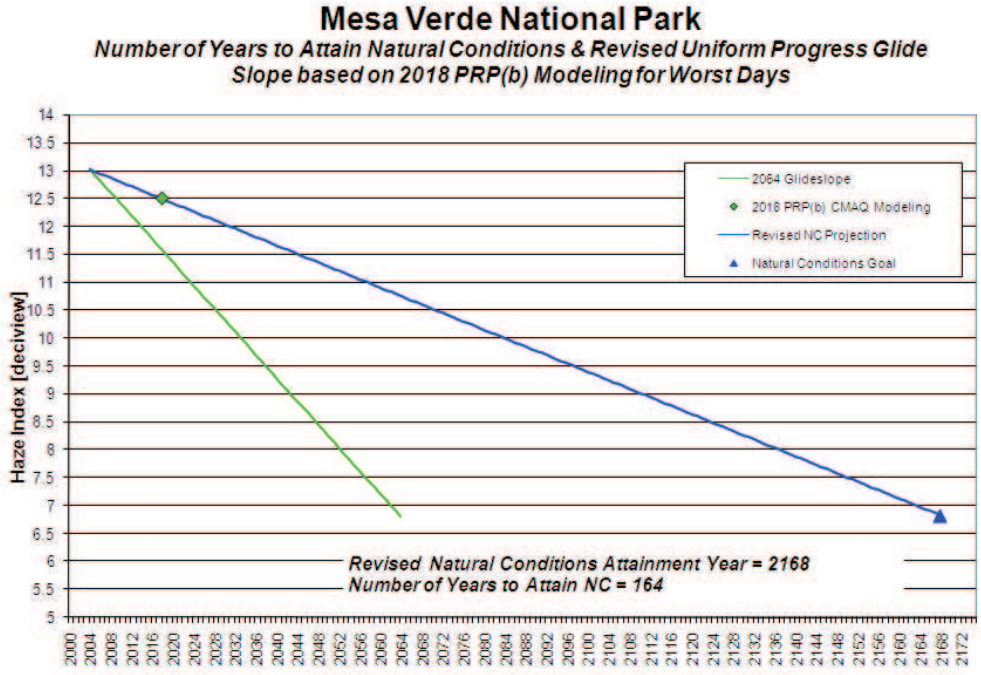


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



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]

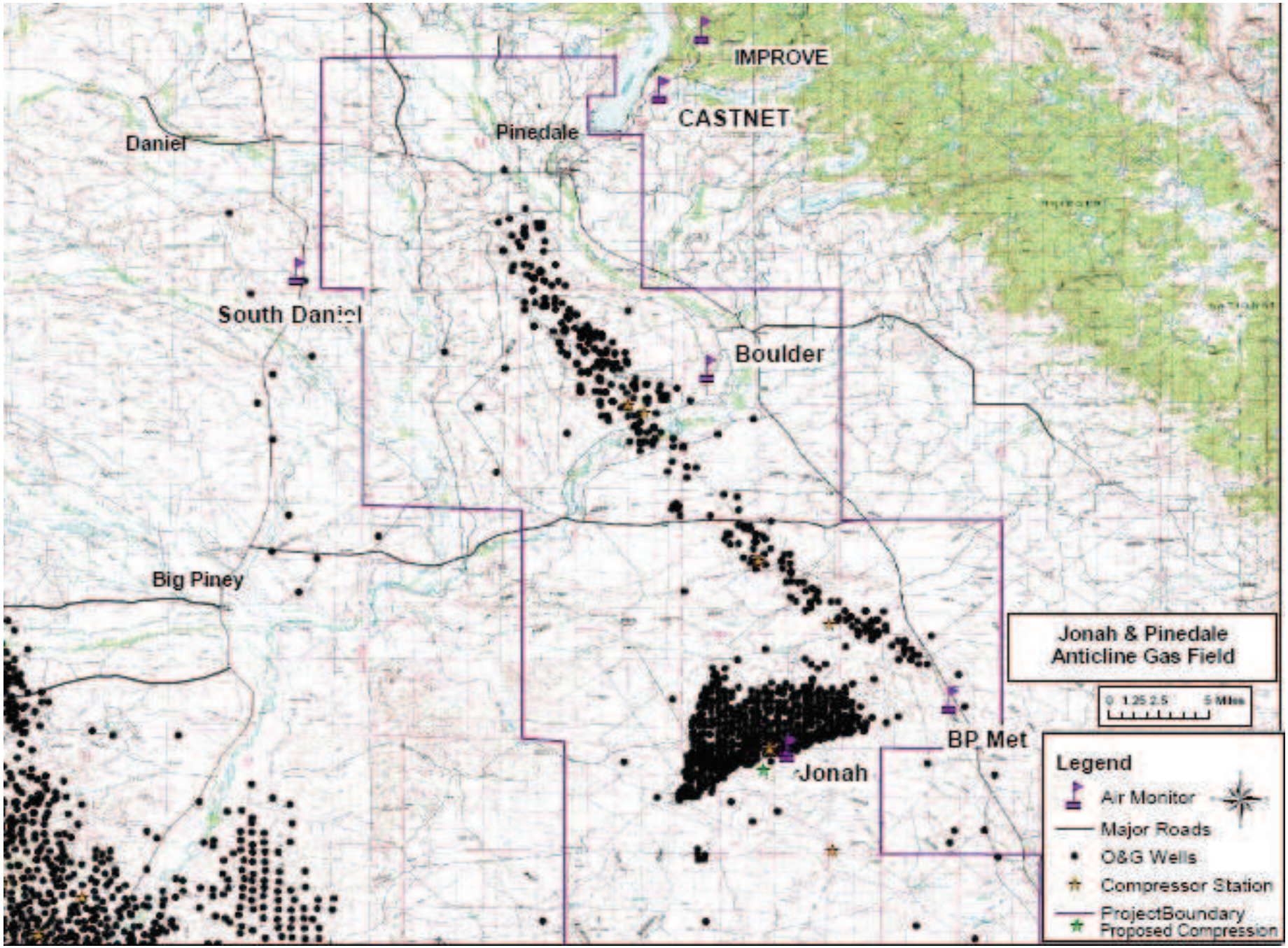
[1]NOAA, Earth System Research Laboratory, Boulder, CO 80305

[2]Wyoming Department of Air Quality, Cheyenne, WY

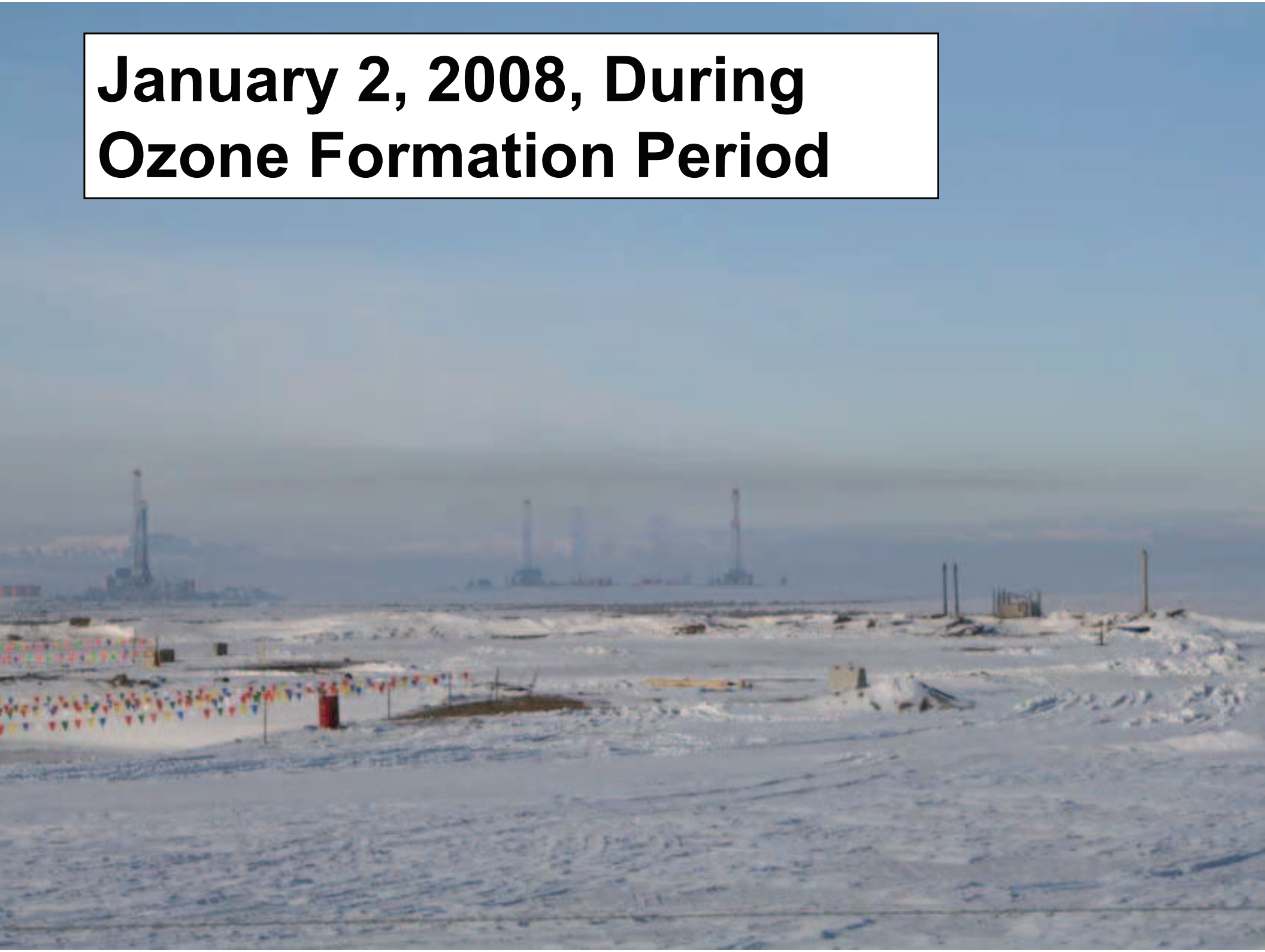
[3]Air Resource Specialists, Fort Collins. CO

My Documents,
Wyoming Ozone

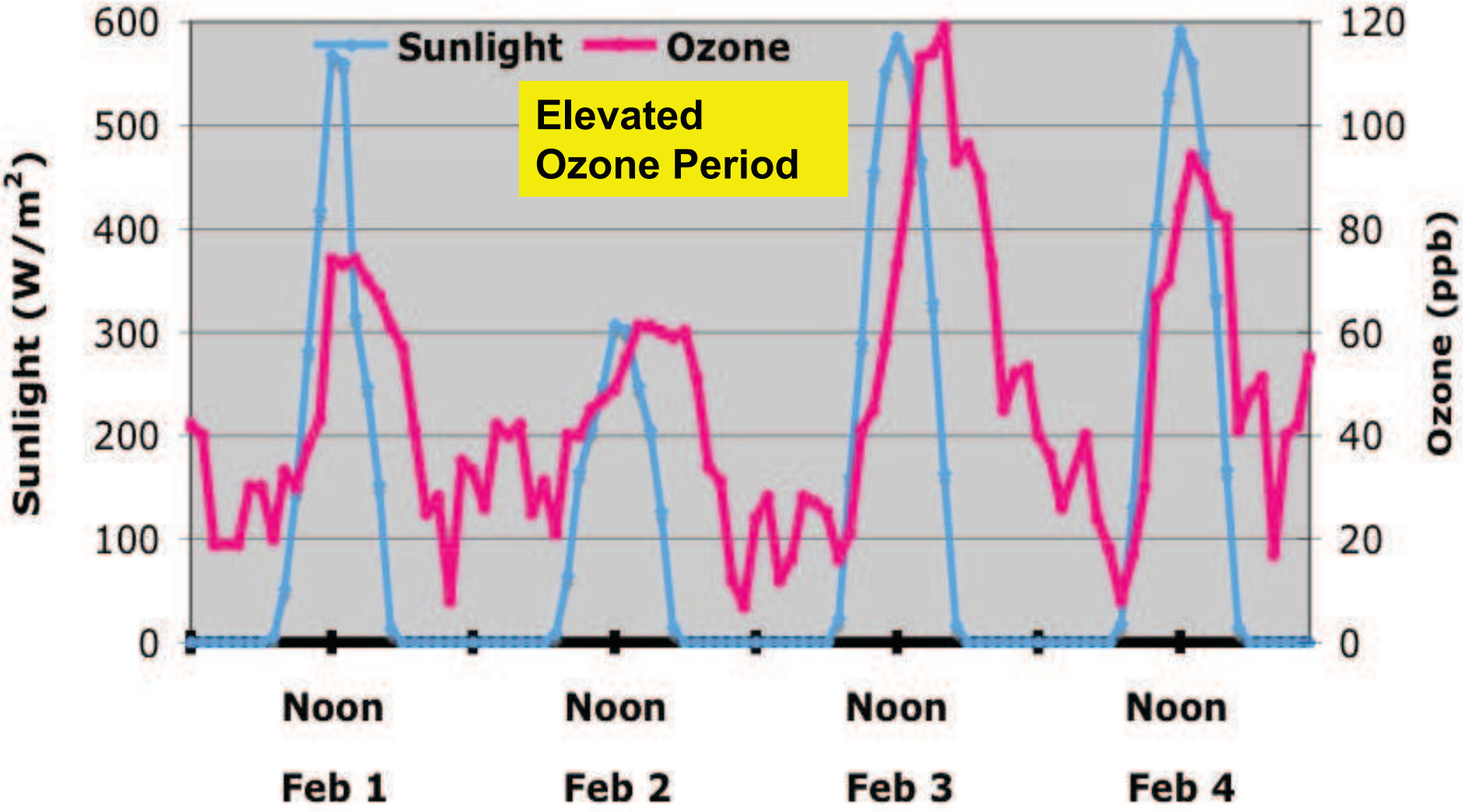
Pinedale Anticline, Jonah, Wyoming



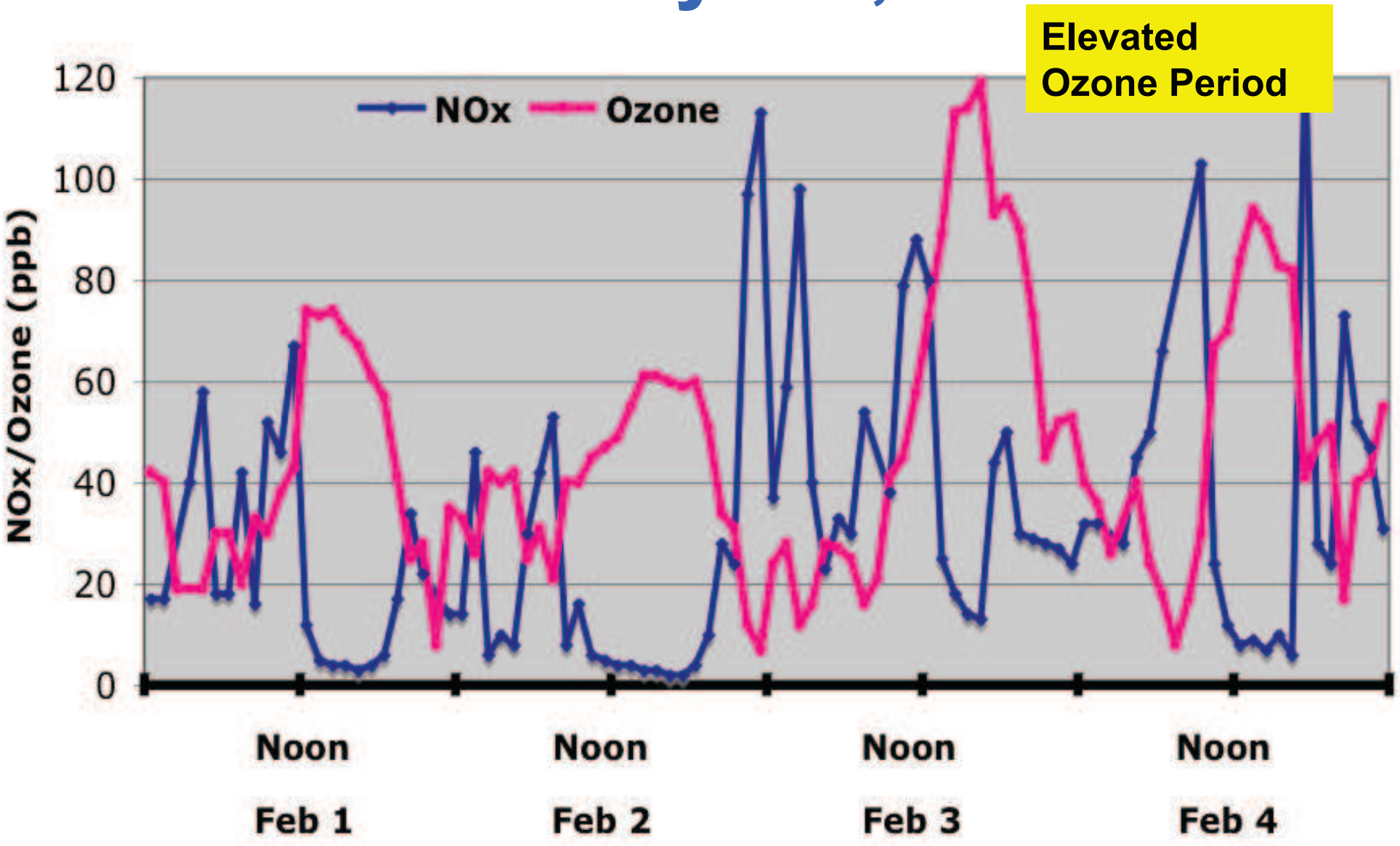
Well Density will increase 300% in 3-5 Years


January 2, 2008, During
Ozone Formation Period

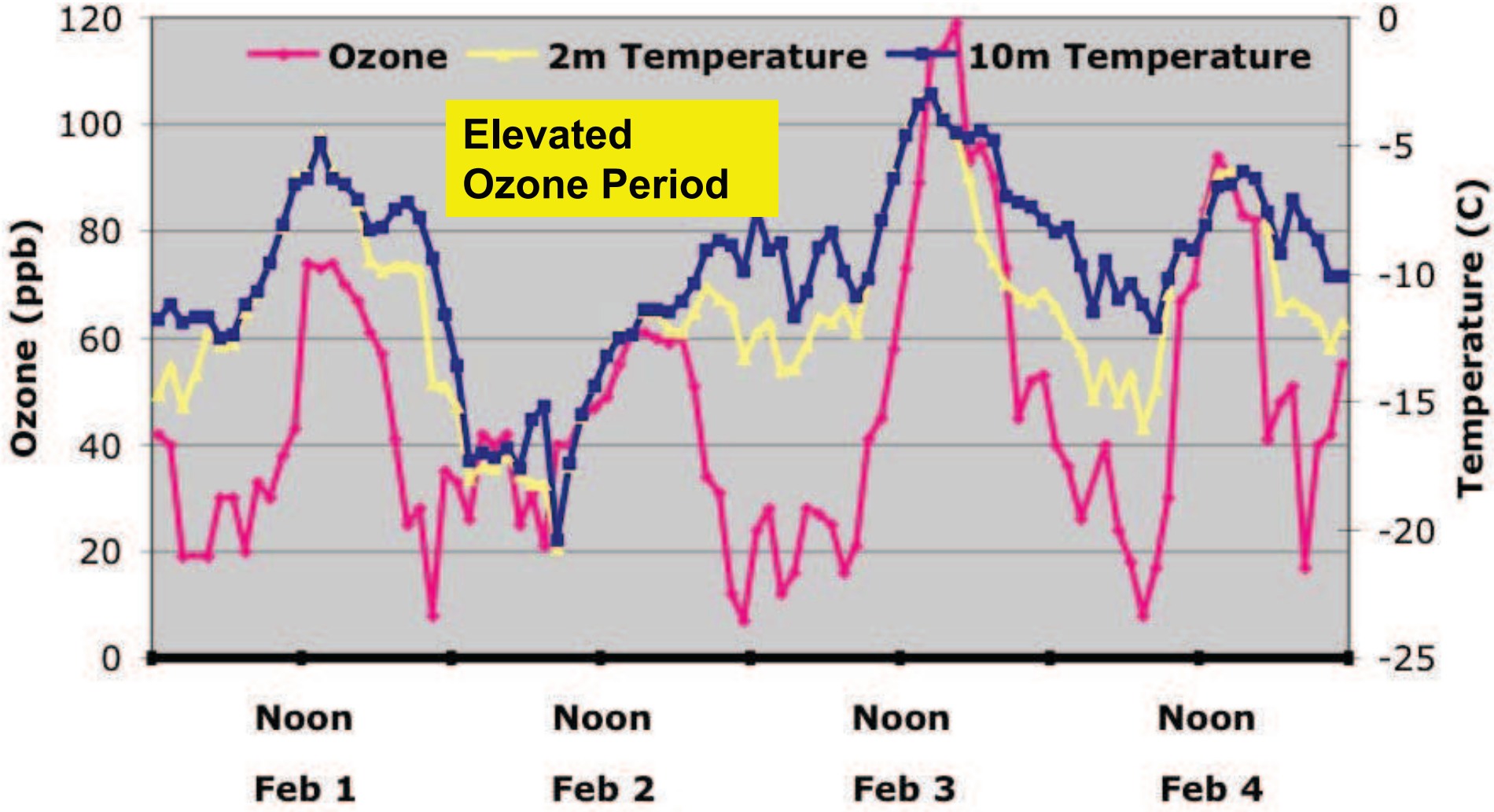
Solar Radiation and Ozone, Jonah, February 1-4, 2005



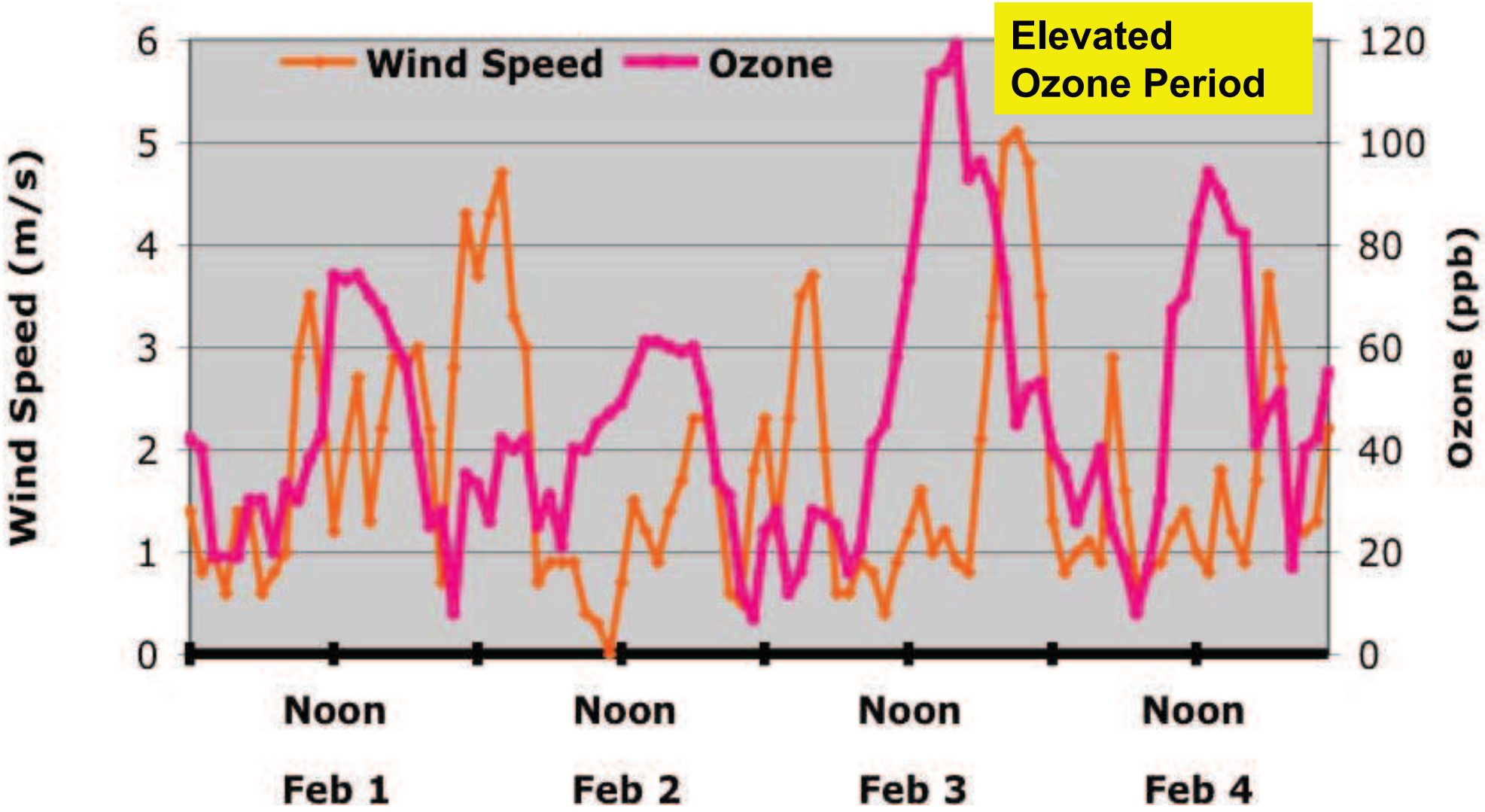
Ozone and NOx, Jonah, February 1-4, 2005



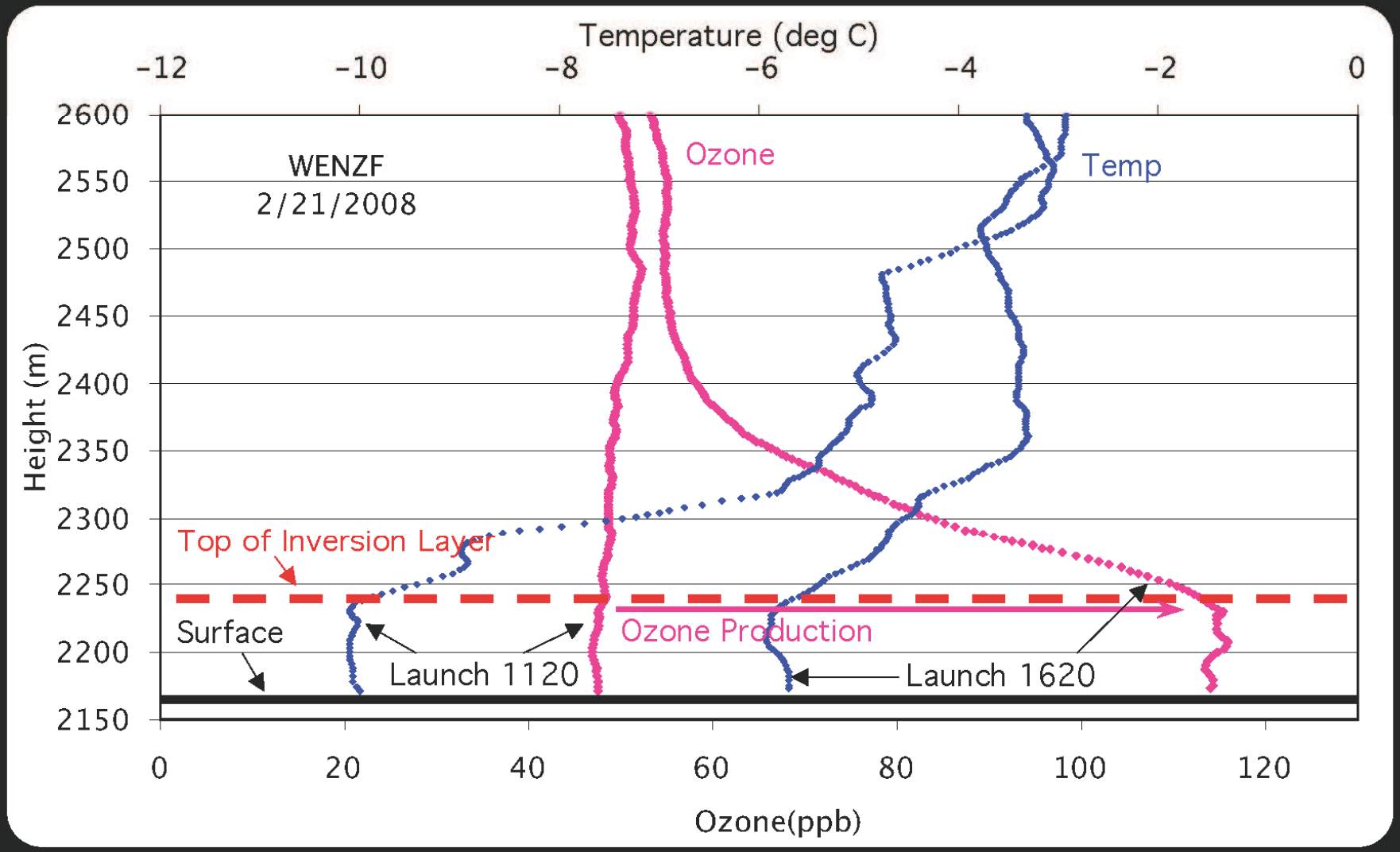
Ozone and Temperature, Jonah, February 1-4, 2005



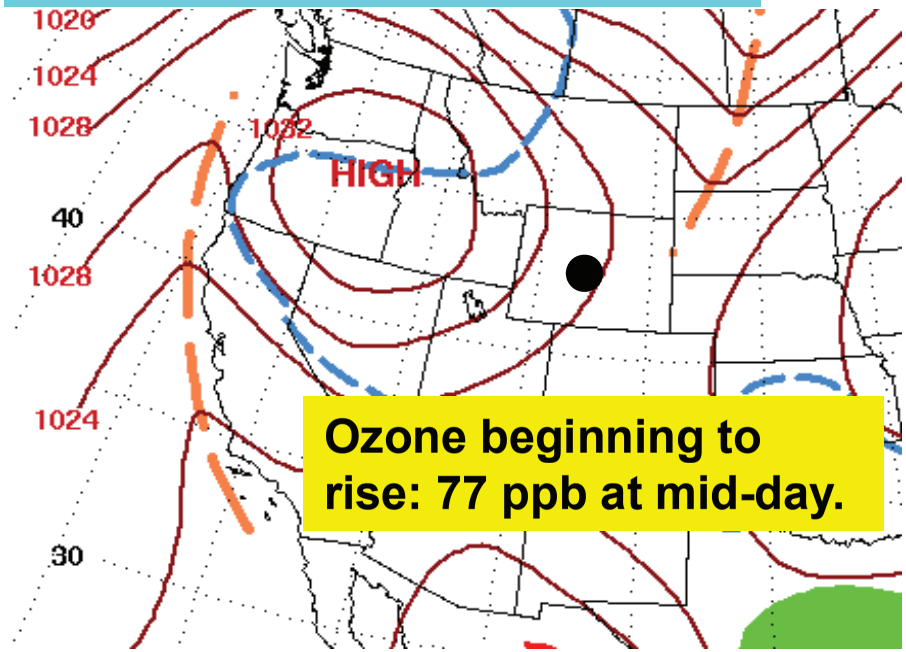
Ozone and Wind Speeds, Jonah, WY, Feb 1-4, 2005



Ozonesondes

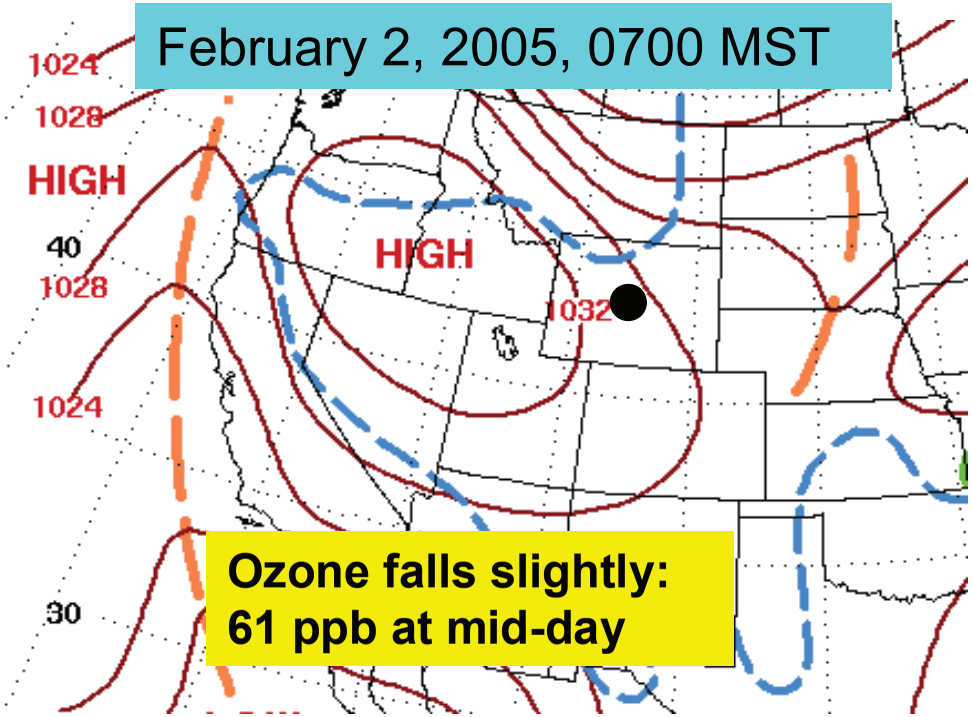


February 1, 2005, 0700 MST



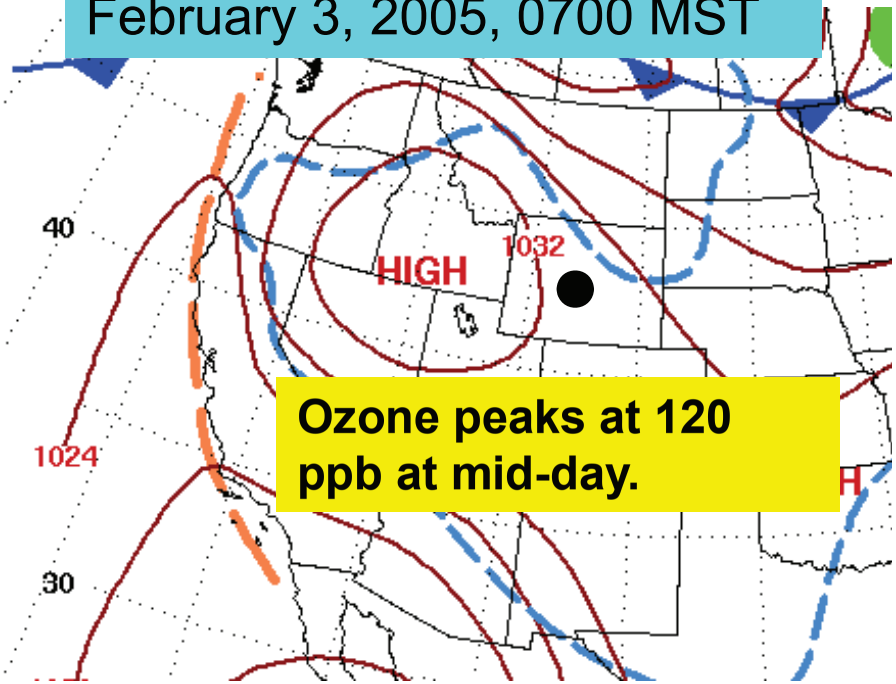
Ozone beginning to rise: 77 ppb at mid-day.

February 2, 2005, 0700 MST



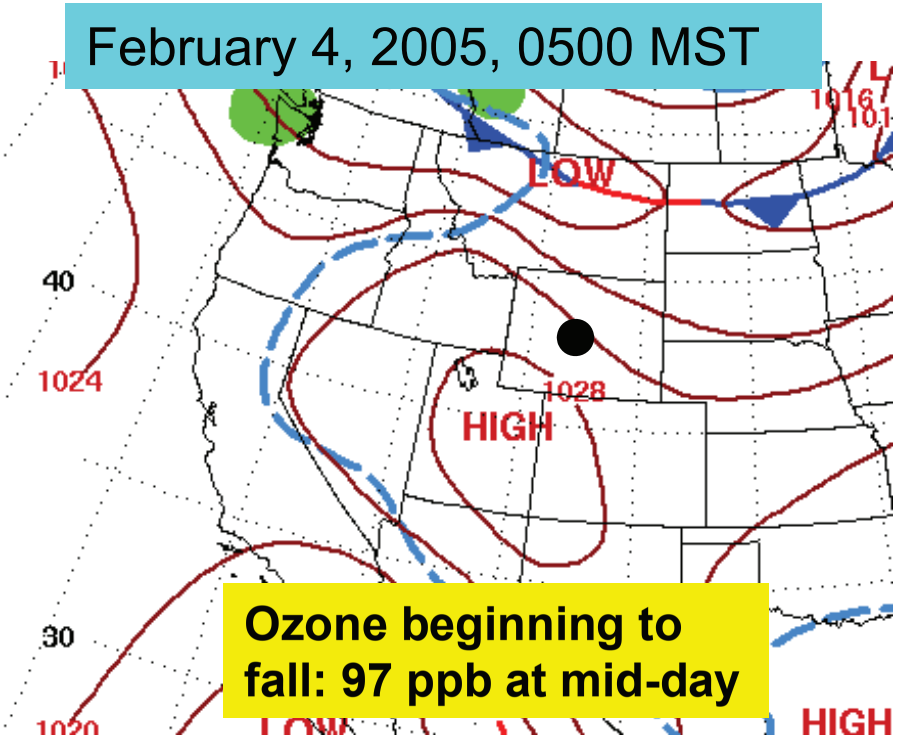
Ozone falls slightly: 61 ppb at mid-day

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

[1] The recommendation does not extend to lands under the jurisdiction of Tribal Authority.

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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

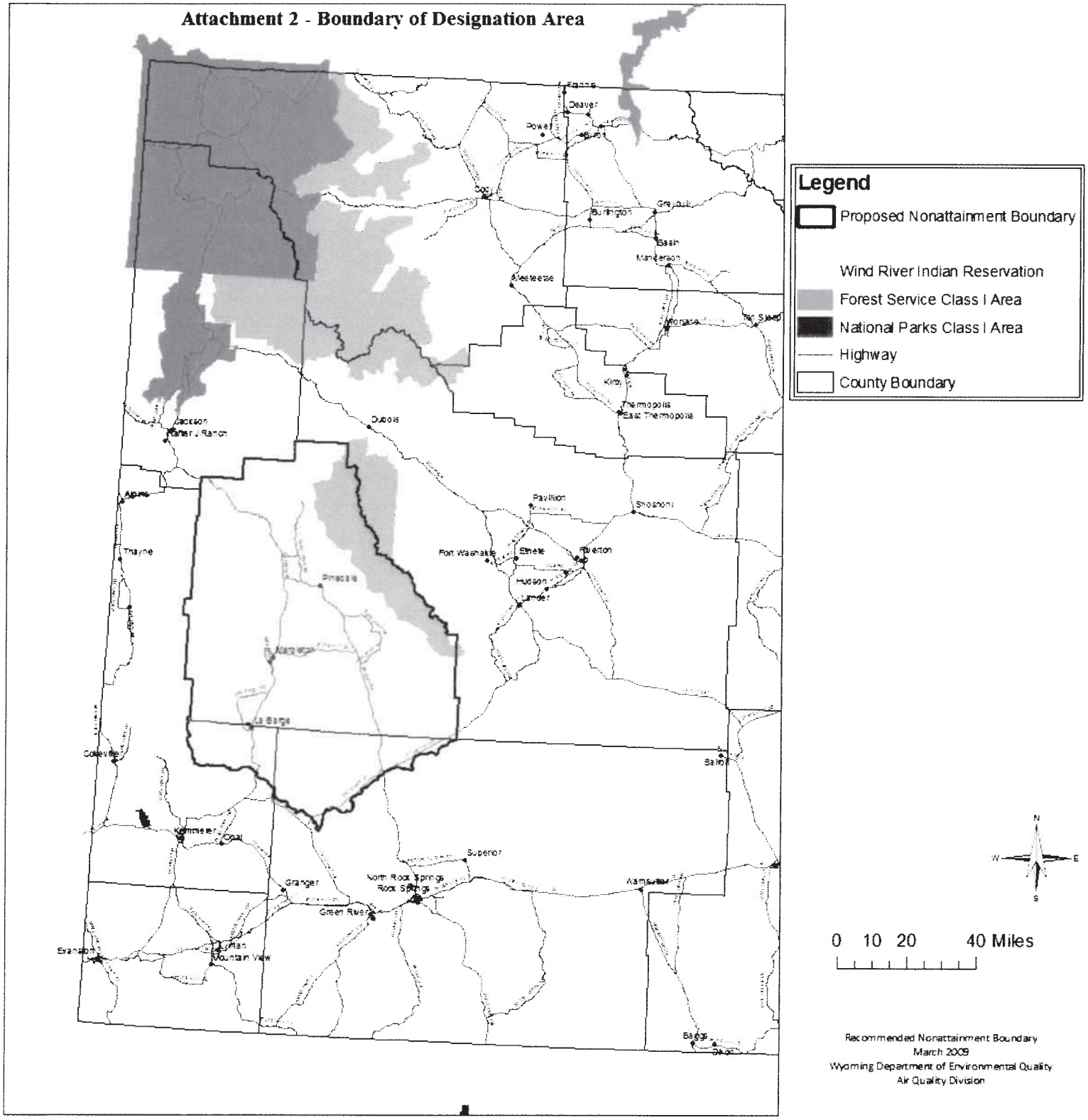
Attachment 1

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

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]

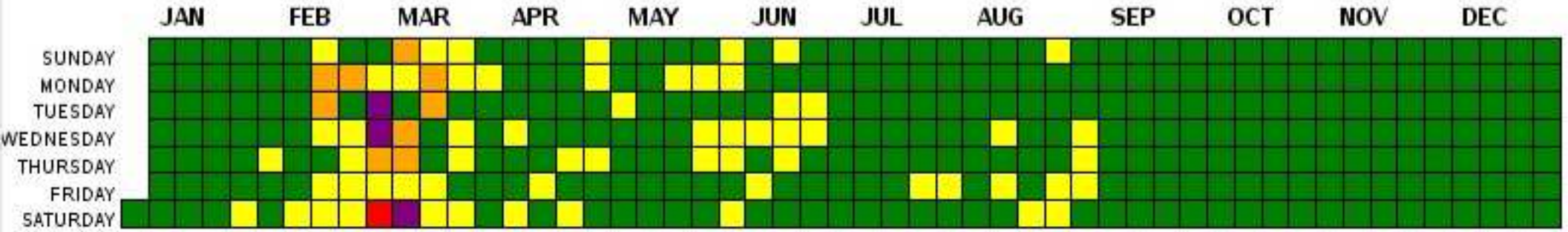
[1] Data collected and validated through 3rd quarter 2008
[2] Incomplete year; began operation in July 2005
[3] Incomplete year; began operation in February 2005
[4] One quarter with less than 75% data completeness

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

Daily Ozone AQI Levels in 2011
Sublette County, WY



Good (<=0.059 ppm)	291 days
Moderate (0.060-0.075 ppm)	61 days
Unhealthy for Sensitive Groups (0.076-0.095 ppm)	9 days
Unhealthy (0.096-0.115 ppm)	1 days
Very Unhealthy (>=0.116 ppm)	3 days

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

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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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?
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John Spencer Score: 0
10:08 AM on March 9, 2011
Now there's an idea pencil-pusher.
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rawn Score: 0
10:09 AM on March 9, 2011
Typical red state filled with oil and smog. Texas must be jealous.
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False_Paradigm Score: 1
10:10 AM on March 9, 2011
DRILL BABY DRILL!!! DERP AH-DERPITY DOO!!!
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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.
Report Abuse

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