Bureau of Land Management, New Mexico State Office, March 2017

AIR RESOURCES TECHNICAL REPORT FOR OIL AND GAS DEVELOPMENT

NEW MEXICO, OKLAHOMA, TEXAS AND KANSAS

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AIR RESOURCES TECHNICAL REPORT FOR OIL AND GAS DEVELOPMENT IN NEW MEXICO, OKLAHOMA, TEXAS AND KANSAS

The purpose of this document is to summarize the technical information on air quality and climate change relative to all Environmental Assessment (EAs) for Application for Permit to Drill (APD) and Lease sales. The intent of this document is to collect and present the data and information needed for air quality and climate change analysis pertaining to oil and gas development. This information can then be incorporated by reference into the site-specific National Environmental Policy Act (NEPA) documents as necessary. In addition, data is included in the appendices which can be incorporated into the site specific analysis included in the APD EAs.

While much of the information in this document is generic and applies to all areas of the United States, some sections refer specifically to New Mexico. Because the Bureau of Land Management (BLM) manages extensive land holdings in New Mexico, far more of its activities are centered there. The New Mexico State Office also has jurisdiction over development of federal mineral rights in Kansas, Texas, and Oklahoma. Wherever possible, information for those states is included. In addition, separate sections have been added for each state outside New Mexico at the end of the report in order to ensure completeness.

In March 2017, an update to this document was completed that incorporates the latest available air quality data, and information about regulatory changes that have occurred since February 2016 and new scientific data that is relevant to air quality and climate change. New information was added about Kansas, Texas and Oklahoma air quality data to comprehensively address air quality in all areas where the BLM New Mexico State Office has jurisdiction.

AIR RESOURCES

Air quality and climate are components of air resources which may be affected by BLM applications, activities, and resource management. Therefore, the BLM must consider and analyze the potential effects of BLM and BLM-authorized activities on air resources as part of the planning and decision making process. In particular, the activities surrounding oil and gas development are likely to have impacts related to air resources.

AIR QUALITY

The Clean Air Act, as amended, is the primary authority for regulation and protection of air quality in the United States. The Federal Land Policy and Management Act (FLPMA) also charges BLM with the responsibility to protect air and atmospheric values.

All areas of the United States not specifically classified as Class I by the Clean Air Act are considered to be Class II for air quality. Class I areas are afforded the highest level of protection by the Clean Air Act and include all international parks, national wilderness areas and national memorial parks >5,000 acres, and national parks >6,000 acres in size which were in existence on August 7, 1977. Moderate amounts of air quality degradation are allowed in Class II areas. While the Clean Air Act allows for designation of Class III areas where greater amounts of degradation would be allowed, no areas have been successful in receiving such designation by the EPA. Air quality in a given area is determined by levels and chemistry of atmospheric pollutants, dispersion meteorology, and terrain.

CRITERIA AIR POLLUTANTS

The U.S. Environmental Protection Agency (EPA) has the primary responsibility for regulating atmospheric emissions, including six nationally regulated air pollutants defined in the Clean Air Act. These pollutants, referred to as "criteria pollutants," include carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM_{10} & $PM_{2.5}$), sulfur dioxide (SO_2) and lead (Pb). The Clean Air Act charges EPA with establishing and periodically reviewing National Ambient Air Quality Standards (NAAQS) for each criteria pollutant. Table 1 shows the current NAAQS for each pollutant. Regulation and enforcement of the NAAQS has been delegated to the states by the EPA. New Mexico Ambient Air Quality Standards (NMAAQS) are also shown. Oklahoma, Kansas and Texas do not have state standards for criteria pollutants that differ from the NAAQS.

Table 1. National Ambient Air Quality Standards (U.S. Environmental Protection Agency, 2016)

	Primary Standards		**Secondary Standards**		**New Mexico AAQS***
Pollutant	**Level**	**Averaging Time**	**Level**	**Averaging Time**	
Carbon Monoxide	9 ppm (10 mg/m^3)	8-hour [1]	None		8.7ppm
	35 ppm (40 mg/m^3)	1-hour [1]			13.1 ppm
Lead	0.15 µg/m^3	Rolling 3-Month Average	Same as Primary		None
Nitrogen Dioxide	53 ppb	Annual (Arithmetic Average)	Same as Primary		50ppb
	100 ppb	1-hour [2]	None		100ppb (24-hour)
Particulate Matter (PM_{10})	150 µg/m^3	24-hour [3]	Same as Primary		**TSP 150 µg/m^3 (24-hr) **TSP 110 µg/m^3 (7-day)
Particulate Matter ($PM_{2.5}$)	12.0 µg/m^3	Annual [4] (Arithmetic Average)	15.0 ug/m^3 (Annual) [4] (Arithmetic Average)		**TSP 90 µg/m^3 (30-day)
	35 µg/m^3	24-hour [5]	Same as Primary		**TSP 60 µg/m^3 (annual geometric mean)
Ozone	0.070 ppm	8-hour [6]	Same as Primary		None

Sulfur Dioxide	75 ppb	1-hour[7]	0.5 ppm [1] (3-hour)	0.02 ppm (annual) 0.10 ppm (24-hour)

* 20.2.3 NMAC, **Total Suspended Particulates

[1] Not to be exceeded more than once per year.

[2] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 ppb (effective January 22, 2010).

[3] Not to be exceeded more than once per year on average over 3 years.

[4] To attain this standard, the 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors must not exceed 12.0 $\mu g/m^3$.

[5] To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 $\mu g/m^3$ (effective December 17, 2006).

[6] To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.070 ppm.

[7] To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

EPA provides two types of data for each criteria air pollutant. One type of data is annual average concentrations measured at air monitors. Monitors measure concentrations of pollutant in the atmosphere and the results are presented in parts per million (ppm) or micrograms/cubic meter ($\mu g/m^3$). EPA and states periodically analyze and review monitor locations, discontinuing monitoring at locations where pollutant concentrations have been well below the standards and adding monitors in areas where pollutant concentrations may be approaching air quality standards. Monitored criteria pollutant level data can be obtained from EPA's AirData website (U.S. Environmental Protection Agency, 2017a). The second type of data is from the National Emissions Inventory (NEI), the most recent NEI data are from 2014 (U.S. Environmental Protection Agency, 2016d). Emissions data is expressed in tons per year or total volume of pollutant released to the atmosphere. Emissions data is useful in comparing source categories to determine which industries or practices are contributing the most to the general level of pollution in an area.

The NEI data present the emissions of each criteria pollutant by county for major source sectors. National emissions trends are reported in the 2014 NEI Report (U.S. Environmental Protection Agency, 2017b). Details of the sectors mentioned in the report are:

(1) Electricity generation is fuel combustion from electric utilities;

(2) Fossil fuel combustion is fuel combustion from industrial boilers, internal combustion engines, and commercial/institutional or residential use;

(3) Industrial processes include manufacturing of chemicals, metals, and electronics, storage and transfer operations, pulp and paper production, cement manufacturing, petroleum refineries, and oil and gas production;

(4) On-road vehicles category includes both gasoline- and diesel-powered vehicles for on-road use;

(5) Non-road equipment includes gasoline- and diesel-powered equipment for non-road use, as well as planes, trains, and ships;

(6) Road dust includes dust from both paved and unpaved roads. Presentation of emissions data by source sector provides a better understanding of the activities that contribute to criteria pollutant emissions.

NEI data for New Mexico, Kansas, Oklahoma and Texas can be found in Appendix A.

OZONE (O_3)

Ground level ozone is not emitted directly into the air, but is created by chemical reactions between NO_x (oxides of nitrogen) and volatile organic compounds (VOC) in the presence of sunlight. Emissions from industrial facilities and electric utilities, motor vehicle exhaust, gasoline vapors, and chemical solvents are some of the major sources of NO_x and VOC (U.S. Environmental Protection Agency, 2014a). VOCs refer to “volatile” organic chemical compounds which participate in atmospheric photochemical reactions to form secondary pollutants such as ozone which can affect the environment and human health. VOCs are emitted from a variety of sources, such as refineries, oil and gas production equipment, industrial processes, automobiles, consumer products and natural (or biogenic) sources, such as trees and plants. While ozone and NO_2 are criteria air pollutants, VOCs are not.

Nationally, ozone concentrations at urban and rural sites have decreased 22% from 1990 to 2015. Weather conditions have a significant role in the formation of ozone. Ozone is most readily formed on warm summer days when there is stagnation. Because of this role that weather plays in ozone production, EPA uses a model to account for weather-related variability of ozone concentrations and provide a more accurate assessment of the underlying trend in ozone precursor emissions. Removing the effects of weather, national ozone concentrations in rural areas have decreased approximately 11% from 2000 to 2015. In Carlsbad, NM, removing the effects of weather, ozone concentrations increased

8% between 2000 and 2012, while ozone concentrations in Farmington, NM decreased 6% from 2000 to 2012. Ozone concentrations in Tulsa, Oklahoma decreased 23% from 2000 to 2015 and in Oklahoma City decreased 18% from 2000 to 2015.Removing the effects of weather, ozone concentrations in Kansas were the same in 2012 as in 2000. In Texas, ozone concentrations decreased substantially removing the effects of weather, especially in large urban areas. Houston, Longview and Dallas ozone concentrations decreased from 11-27% between 2000 and 2012, while concentrations in Austin and El Paso decreased by 2-3%. San Antonio's ozone concentrations increased 5% between 2000 and 2015, removing the effects of weather (U.S. Environmental Protection Agency, 2016a).

VOCs are emitted during well drilling and operations as exhaust from internal combustion engines. VOCs may be emitted from hydraulically fractured oil and gas wells during the fracturing and re-fracturing of the wells. In the hydraulic fracturing process, a mixture of water, chemicals and proppant is pumped into a well at extremely high pressures to fracture rock and allow oil and gas to flow from the geological formation. During one stage of well completion, fracturing fluids, water and reservoir gas come to the surface at high velocity and volume (flowback). This flowback mixture contains VOCs, methane, benzene, ethylbenzene and n-hexane; some or all of the flowback mixture may be vented, flared or captured. The typical flowback process lasts from 3 to 10 days, so there is potential for significant VOC emissions from this stage of the well completion process. Most new oil and gas wells drilled today use the hydraulic fracturing process. VOCs are also a component of natural gas and may be emitted from equipment leaks, valves, pipes and pneumatic devices. NOx emissions are discussed below under NO_2.

An emissions inventory conducted for the Carlsbad Field Office for calendar year 2007 and including Chaves, Lea, and Eddy counties (Applied Enviro Solutions, 2011) shows that VOC emissions from biogenic (natural) sources are far greater than those from anthropogenic (human) sources and account for 91% of VOCs inventoried. Point source emissions (which might include such industrial sources as power plants, gas plants and oil refineries) account for 40% of anthropogenic VOC emissions in the area, solvent use accounts for 15%, and fire (including wildland, structure, and open burning) accounts for 8%. Oil and gas area sources produce only 1.4% of VOCs in the area while pipeline transport of oil and gas accounts for 1.7%.

An emissions inventory conducted for the Four Corners region for calendar year 2005, including counties in northwestern New Mexico, southwestern Colorado, southeastern Utah and northeastern Arizona, estimates VOC emissions from biogenic sources account for 55% of total VOCs (Environ, 2009). In this study, biogenic VOC emissions were calculated not measured. Oil and gas area and point sources accounted for 28% of VOCs inventoried.

The 2014 NEI for the entire state of New Mexico estimates VOC emissions from biogenic sources account for 82% of total VOCs in the state. VOCs from fire account for 2% and industrial processes account for 12% of total VOCs. According to the 2014 NEI, Texas biogenic emissions account for 72% of

total VOC emissions, while industrial processes account for 17% of VOC emissions. VOC emissions from fire account for 2% of Texas VOC emissions, mobile sources account for 3% of total VOC emissions, and solvents account for 4% of total VOC emissions. In Oklahoma, biogenic emissions are estimated to be 69% of total VOC emissions, industrial processes account for 14%, fire accounts for 7% of total VOC emissions, and mobile sources account for 4% of total VOC emissions. In Kansas, biogenics account for 64% of total VOC emissions, fire accounts for 9% of VOC emissions, industrial processes account for 14% of VOC emissions, mobile sources account for 5% of VOC emissions, and solvents account for 6% of VOC emissions (U.S. Environmental Protection Agency, 2016d).

The current NAAQS for ozone is the three-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration, which for simplicity is sometimes referred to as the "design value." Between 1997 and 2008, the NAAQS for ozone was 0.08 ppm. To attain this standard, the design value for ozone at any monitor in the U.S. could not exceed 0.084 ppm. In 2008, the NAAQS for ozone was lowered to 0.075 ppm. In 2015, the NAAQS for ozone was lowered to 0.070 ppm.

In 2009, a photochemical modeling analysis was completed for the Four Corners Air Quality Task Force (FCAQTF). Potential ozone impacts and the usefulness of certain mitigation measures were analyzed. This modeling showed that the Four Corners region would continue to meet the current ozone standard in 2018 with continued oil and gas development and population growth. The analysis showed that emissions reductions would be required for both power plants and oil and gas sources in order to achieve measurable reductions in ozone concentrations. The best achievable ozone reductions from the modeling scenarios implementing control measures to reduce emissions were on the order of 5 ppb (Environ, 2009).

The modeling analysis completed for FCAQTF also used source apportionment modeling, which indicated that, in general, transport from outside the region and naturally occurring VOCs from vegetation were large contributors to 2005 ozone levels. However it was also shown that on days with high ozone concentrations, oil and gas sources and electricity generation units (EGUs) both contributed significantly to the total modeled ozone concentrations.

In 2013, the Western Regional Air Partnership (WRAP) completed a regional technical analysis for ozone (WestJump) that includes information about ozone impacts and sources that contribute to the formation of ozone for calendar year 2008. The analysis demonstrated that the largest contributor to ozone concentrations in the western U.S. was international transport and stratospheric ozone. State-to-state ozone transport was important, as well. For example, New Mexico sources significantly contribute to elevated ozone concentrations in Texas, Arizona and Colorado. Texas is a significant contributor to elevated ozone in Oklahoma, Louisiana, New Mexico, Missouri and Arizona. Kansas sources significantly contribute to elevated ozone in Missouri and Texas, while Oklahoma sources significantly contribute to elevated ozone in Missouri, Texas and New Mexico (ENVIRON International Corporation, Alpine Geophysics, LLC and University of North Carolina, 2013).

NITROGEN DIOXIDE (NO_2)

NO_2 is both a criteria pollutant and an indicator for the NO_x family of nitrogen oxide compounds that are ground-level ozone precursors. The nitrogen oxide family of compounds includes nitric oxide (NO), nitrogen dioxide (NO_2), nitrous acid ($HN0_2$), and nitric acid (HNO_3). The primary sources of NO_x nationally are motor vehicles and fuel combustion. The excess air required for complete combustion of fuels in these processes introduces atmospheric nitrogen into the combustion reactions at high temperatures and produces nitrogen oxides. NO_2 has been shown to cause adverse respiratory impacts in both healthy people and those with asthma, and is also an important contributor to the formation of ground-level ozone (U.S. Environmental Protection Agency, 2014b).

Nationally, NO_2 concentrations have decreased substantially (47% reduction) from 2000 to 2015. In the southwest (Arizona, New Mexico, Colorado and Utah), NO_2 concentrations have decreased 32% between 2000 and 2015; in the south (Texas, Oklahoma, Kansas, Arkansas, Louisiana and Mississippi), NO_2 concentrations have decreased 27% between 2000 and 2015. EPA expects NO_2 concentrations will continue to decrease because of a number of motor vehicle standards that are taking effect (U.S. Environmental Protection Agency, 2016b).

NO_x emissions in the Carlsbad area are largely anthropogenic (88%). Of the total human-caused NOx emissions, industrial point sources account for 84%, on-road mobile sources account for 7%, oil and gas area sources account for 5%, non-road mobile sources account for 2%, and residential heating with natural gas and propane account for 1% (Applied Enviro Solutions, 2011).

The top three sources of NO_x emissions in the Farmington area in 2005 were electricity generation (72,668 tons; 33%), oil and gas (68,830 tons; 31%) and on-road mobile sources (39,340 tons; 18%) (Environ, 2009).

The 2014 National Emissions Inventory data for the Farmington area (San Juan County), indicates that fuel combustion accounts for 56% of total NOx emissions, industrial sources account for 34% of total NOx emissions, and mobile sources account for 9% of total NOx emissions in the area (U.S. Environmental Protection Agency, 2016d).

The 2014 National Emissions Inventory data for the state of New Mexico indicate mobile sources account for 44%, fuel combustion accounts for 22%, industrial processes account for 19%, biogenics account for 13% and fire accounts for less than 1% of total NO_x emissions in the state. For Texas, the 2014 National Emissions Inventory data indicate mobile sources account for 47%, fuel combustion accounts for 19%, industrial processes account for 25%, biogenics account for 8% and fire accounts for less than 1% of total NO_x emissions in the state. In Oklahoma, mobile sources account for 35%, fuel combustion accounts for 29%, industrial processes account for 24%, biogenics account for 10% and fire accounts for 2% of total Oklahoma NO_x emissions. In Kansas, mobile sources account for 41%, fuel

combustion accounts for 20%, industrial processes account for 20%, biogenics account for 16% and fire accounts for 3% of total Kansas NO_x emissions (U.S. Environmental Protection Agency, 2016d).

CARBON MONOXIDE (CO)

Carbon monoxide is produced from the incomplete burning of carbon-containing compounds such as fossil fuels; it forms when there is not enough oxygen to produce carbon dioxide (CO_2). Nationally, 86% of CO emissions come from transportation sources. CO is associated with negative health effects to human cardiovascular, central nervous, and respiratory systems (U.S. Environmental Protection Agency, 2014c). There are currently no non- attainment areas for CO in the United States (U.S. Environmental Protection Agency, 2016e).

Nationally, CO concentrations have decreased 77% from 2000 to 2015. Monitored CO concentrations in the "southwest" region (New Mexico, Arizona, Colorado and Utah) have decreased 60% between 2000 and 2015. Monitored CO concentrations in the "south" region (Texas, Oklahoma, Kansas, Arkansas, Louisiana and Mississippi) have decreased 64% between 2000 and 2013 (U.S. Environmental Protection Agency, 2016c).

The 2007 emissions inventory for Chaves, Eddy, and Lea Counties shows that anthropogenic sources account for 65% of CO emissions and biogenic sources 35%. Of the anthropogenic emissions 47% are from on road mobile sources, 24% from industrial point sources, 14% from non-road mobile sources, 9% from fire, and 2% each from oil and gas area sources and waste disposal burning (Applied Enviro Solutions, 2011).

For San Juan County, New Mexico (Farmington area), the 2014 National Emissions Inventory data indicate fires contribute 32%, mobile sources contribute 18%, fuel combustion contributes 15%, industrial processes contribute 21% and biogenics contribute 13% of total CO emissions in the county (U.S. Environmental Protection Agency, 2016d).

For New Mexico, the 2014 National Emissions Inventory data indicate mobile sources account for 34%, industrial processes account for 8%, fuel combustion accounts for 5%, fire accounts for 14% and biogenics account for 37% of total state CO emissions. The 2014 National Emissions inventory data for Texas indicate mobile sources account for 50%, fuel combust accounts for 6%, industrial processes account for 5%, fire accounts for 14% and biogenics account for 21% of total Texas CO emissions. In Oklahoma, mobile sources account for 38%, fuel combustion accounts for 6%, industrial processes account for 7%, fire accounts for 36% and biogenics account for 11% of total CO emissions in the state. In Kansas, mobile sources account for 38%, fuel combustion accounts for 6%, industrial processes account for 9%, fire accounts for 33% and biogenics account for 13% of total CO emissions in the state (U.S. Environmental Protection Agency, 2016d).

PARTICULATE MATTER (PM)

Particulate matter, also known as particle pollution or PM, is a complex mixture of extremely small particles and liquid droplets. PM is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles. PM is measured and regulated according to particle size. PM_{10} refers to all particles with a diameter of 10 microns or less. $PM_{2.5}$ is made up of particles with diameters of 2.5 microns or less. Smaller particles are associated with more negative health effects, including respiratory and cardiovascular problems because they can become more deeply embedded in the lungs (U.S. Environmental Protection Agency, 2013).

Nationally, $PM_{2.5}$ concentrations have decreased 37% from 2000 to 2015. In that same time period, PM_{10} concentrations decreased 36% nationally. In the Four Corners region (New Mexico, Arizona, Colorado and Utah), $PM_{2.5}$ concentrations have decreased 24% from 2000 to 2015, and PM_{10} concentrations have decreased 16% in the same time period. For the southern region encompassing Texas, Oklahoma, Kansas, Arkansas, Louisiana and Mississippi, $PM_{2.5}$ concentrations have decreased 31% and PM_{10} concentrations have decreased 10% between 2000 and 2015 (U.S. Environmental Protection Agency, 2016g) & (U.S. Environmental Protection Agency, 2016f).

A 2007 emissions inventory for Chaves, Eddy, and Lea Counties shows that the bulk of emission for both PM10 and PM2.5 are from dust from unpaved roads (88 and 65% respectively). For PM10, the next three highest categories are point sources at 2.8%, tilling and harvesting 2.6% and paved roads 2.4%. Oil and gas area sources account for only 0.1% of PM10 emissions. For PM2.5, the next three highest categories are point sources at 17%, fire at 4.3% and tilling and harvesting at 2.8%. Oil and gas area sources account for 0.8% of PM2.5 emissions in this area (Applied Enviro Solutions, 2011).

For the Farmington area (San Juan County), the 2014 National Emissions Inventory data show that most particulate matter emissions are from dust ($PM_{2.5}$: 5,062 tons, 56%; PM_{10}: 48,187 tons, 87%) (U.S. Environmental Protection Agency, 2016d).

According to the 2014 National Emissions Inventory, for the entire state of New Mexico, dust accounts for 68% and fire accounts for 12% of $PM_{2.5}$ emissions statewide. For PM_{10}, dust accounts for 91% and fire accounts for 2% of emissions in New Mexico. For Texas, the 2014 National Emissions Inventory data indicate that dust accounts for 45%, fire accounts for 13%, agriculture accounts for 18%, mobile sources account for 6%, fuel combustion accounts for 6% and industrial processes accounts for 6% of statewide $PM_{2.5}$ emissions. Dust accounts for 75%, agriculture accounts for 16% and fire accounts for 3% of Texas PM_{10} emissions. In Oklahoma, fire accounts for 27%, dust accounts for 37%, agriculture accounts for 21%, fuel combustion accounts for 5%, industrial processes account for 4% and mobile sources account for 3% of Oklahoma $PM_{2.5}$ emissions. Dust accounts for 69%, agriculture accounts for 21% and fire accounts for 6% of Oklahoma PM_{10} emissions. In Kansas, dust accounts for 25%, agriculture accounts for 41%, fire accounts for 21%, mobile sources account for 4%, industrial sources account for 3% and fuel

combustion accounts for 4% of Kansas $PM_{2.5}$ emissions. Agriculture accounts for 42%, dust accounts for 49% and fire accounts for 6% of Kansas PM_{10} emissions (U.S. Environmental Protection Agency, 2016d).

The WestJump analysis also provides information about $PM_{2.5}$ impacts and contributing sources for calendar year 2008. Interstate transport is significant for $PM_{2.5}$. New Mexico significantly contributes to annual $PM_{2.5}$ exceedances in Arizona; Texas significantly contributes to exceedances in Arkansas, Missouri, Mississippi, Illinois and Alabama; Oklahoma significantly contributes to exceedances in Arkansas and Missouri, and Kansas significantly contributes to exceedances in Iowa, Missouri, Illinois, Arkansas and Wisconsin. For the 24-hour $PM_{2.5}$ standard, New Mexico significantly contributes to exceedances in California, Texas and Oklahoma significantly contribute to exceedances in Iowa, and Kansas significantly contributes to exceedances in Iowa and Wisconsin (ENVIRON International Corporation, Alpine Geophysics, LLC and University of North Carolina, 2013).

SULFUR DIOXIDE (SO2)

Sulfur dioxide (SO_2) is one of a group of highly reactive gases known as "oxides of sulfur," commonly referred to as SO_x. The largest sources of SO_2 emissions nationwide are from fossil fuel combustion at power plants (73%) and other industrial facilities (20%). Smaller sources of SO_2 emissions include industrial processes, such as extracting metal from ore, and the burning of high sulfur-containing fuels by locomotives, large ships, and non-road equipment. SO_2 is linked with a number of adverse effects on the respiratory system (U.S. Environmental Protection Agency, 2015a).

Nationally, SO_2 concentrations have decreased 81% from 2000 to 2015, but substantial decreases (76% reduction) have occurred since 1980 due to implementation of federal rules requiring reductions in SO_2 emissions from power plants and other large sources of SO_2. In the Four Corners region, SO_2 concentrations decreased 24% between 2000 and 2015. In the southern region of Texas, Oklahoma, Kansas, Arkansas, Louisiana and Mississippi, SO_2 concentrations decreased 76% between 2000 and 2015 (U.S. Environmental Protection Agency, 2016i).

The Carlsbad area, the 2007 emissions inventory does not differentiate SO_2 from SO_x but it can be assumed that the percentage of emissions by category is similar. In this region, oil and gas area sources account for 74% of all SO_x emissions with most of the remainder, 25% accounted for by industrial point sources (Applied Enviro Solutions, 2011).

In the Farmington area nearly all SO_2 emissions come from fuel combustion (5,038 tons; 93%), while 4% of SO_2 emissions come from fires and 3% from industrial sources, according to the 2014 National Emissions Inventory (U.S. Environmental Protection Agency, 2016d).

The 2014 National Emissions Inventory data indicate industrial sources account for 46%, fuel combustion accounts for 44%, fires account for 5%, and mobile sources account for 4%, of New Mexico

SO_2 emissions. Fuel combustion accounts for 78% and industrial processes account for 20% of Texas SO_2 emissions. Fuel combustion accounts for 73%, industrial processes account for 22% and fire accounts for 4% of Oklahoma SO_2 emissions. Fuel combustion accounts for 79%, fire accounts for 8% and industrial processes account for 11% of Kansas SO_2 emissions (U.S. Environmental Protection Agency, 2016d).

LEAD

With the elimination of lead from gasoline and regulation of industrial sources, levels of lead in the atmosphere decreased 94% nationwide between 1980 and 1999. Lead concentrations decreased 60% nationally between 2000 and 2013. While still regulated as a criteria pollutant, the major sources of lead pollution are lead smelters and leaded aviation gasoline. In 2014, EPA proposed to retain the NAAQS for lead without revision (U.S. Environmental Protection Agency, 2014d).

According to the 2014 National Emissions Inventory, aircraft account for 77% of the lead emissions in New Mexico. In Texas, 79% of the lead emissions are from aircraft. In Oklahoma, 47% of lead emissions are from aircraft and 29% are from waste disposal. In Kansas, 81% of lead emissions are from aircraft (U.S. Environmental Protection Agency, 2016d).

HAZARDOUS AIR POLLUTANTS

The U.S. Congress amended the Federal Clean Air Act in 1990 to address a large number of air pollutants that are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects. Congress initially identified 188 specific pollutants and chemical groups as hazardous air pollutants (HAPs) and has modified the list over time.

The Clean Air Act requires control measures for hazardous air pollutants. National emissions standards for hazardous air pollutants (NESHAPs) are issued by EPA to limit the release of specified HAPs from specific industrial sectors. These standards are technology based, meaning that they represent the maximum achievable control technology that is economically feasible for an industrial sector.

The CAA defines a major source for HAPs to be one emitting 10 tons per year of any single HAP or 25 tons per year of any combination of HAPs. Under state regulations, a construction or operating permit may be required for any major source though some exceptions apply. In New Mexico, these regulations are 20.2.70 and 20.2.73 NMAC, in Texas the regulation is 30 TAC 122, in Kansas, the regulation is K.A.R. 28-19-500 and in Oklahoma, the regulation is OAR 252-100-7. Within its definition of a major source in the above referenced regulations the state of New Mexico includes the following language:

> *…hazardous emissions from any oil or gas exploration or production well (with its associated equipment) and hazardous emissions from any pipeline compressor or pump*

> *station shall not be aggregated with hazardous emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources…*

In other words, in determining a major source, each oil and gas exploration and production well must be considered singularly. Kansas, Texas and Oklahoma regulations include similar language.

NESHAPs for Oil and Natural Gas Production and Natural Gas Transmission and Storage were published by EPA on June 17, 1999. These NESHAPs were directed toward major sources and intended to control benzene, toluene, ethyl benzene, mixed xylenes and n-hexane. An additional NESHAP for Oil and Natural Gas Production Facilities directed toward area sources was published on January 3, 2007 and specifically addresses benzene emissions from triethylene glycol dehydrations units. The EPA issued a final rule revising the NESHAP effective October 15, 2012. The final rule includes revisions to the existing leak detection and repair requirements and established emission limits reflecting maximum achievable control technology for currently uncontrolled emission sources in oil and gas production and natural gas transmission and storage (Fed. Reg. 77(159): 49490-49600, August 16, 2012).

The state of New Mexico incorporates federal NESHAPs for pollutants through updates to 20.2.78 NMAC, which adopts 40 CFR Part 61, and federal NESHAPs for source categories through updates to 20.2.82 NMAC, which adopts 40 CFR Part 63. Similarly, Texas incorporates federal NESHAPs for both 40 CFR 61 and 40 CFR 63 through updates to 30 TAC 113. Kansas incorporates federal NESHAPs by adopting 40 CFR 61 through updates to K.A.R. 28-19-735 and incorporates NESHAP source categories at 40 CFR 63 through updates to K.A.R. 28-19-750. Oklahoma incorporates both 40 CFR 61 and 40 CFR 63 through O.A.R. 252-100-41-2 and Appendix Q.

In March 2011, EPA published the fourth in a series of National Scale Air Toxics Assessments (NATA). Based on 2005 data including the National Emissions Inventory, the NATA is intended to be a tool to help focus emissions reduction strategies (U.S. Environmental Protection Agency, 2013a). Computer models are used to develop estimates of risk of cancer or other health impacts from air toxic emissions. NATA presents risk hazard indexes for cancer, neurological and respiratory problems for each county and census tract. Because techniques have changed over the years, each NATA is not comparable to those previously issued. EPA also cautions that because data availability varies from state to state, the results are not necessarily comparable from one geographic area to another. NATA data for New Mexico, Kansas, Oklahoma, and Texas can be found in Appendix B.

HYDROGEN SULFIDE (H_2S)

H_2S is a colorless flammable gas with a rotten egg smell which is a naturally occurring byproduct of oil and gas development in some areas, including the New Mexico portion of the Permian Basin. Hydrogen sulfide is both an irritant and a chemical asphyxiant with effects on both oxygen utilization and the

central nervous system. Its health effects can vary depending on the level and duration of exposure. Effects may range from eye, nose and throat irritation to dizziness, headaches and nausea. High concentrations can cause shock, convulsions, inability to breathe, extremely rapid unconsciousness, coma and death. Effects can occur within a few breaths, and possibly a single breath.

H_2S was originally included in the list of Toxic Air Pollutants defined by Congress in the 1990 amendments to the Clean Air Act. It was later determined that H_2S was included through a clerical error and it was removed by Congress from the list. H_2S was addressed under the accidental release provisions of the Clean Air Act. Congress also tasked EPA with assessing the hazards to public health and the environment from H_2S emissions associated with oil and gas extraction. That report was published in October 1993 (U.S. Environmental Protection Agency, 1993).

EPA found that while there was a potential for human and environmental exposure from routine emissions of H_2S from oil and gas wells, there was insufficient evidence to suggest that these exposures were a significant threat. H_2S is present in some oil and gas production zones. Flaring is used to reduce the H_2S emissions and the CFO has developed a series of standard conditions of approval for high H_2S areas in order to mitigate the risk of H_2S exposure.

Hydrogen Sulfide was added to the Emergency Planning and Community Right-to-Know Act list of toxic chemicals in 1993. In 1994, EPA issued an administrative stay of reporting requirements for H_2S while further analysis was conducted. The administrative stay was lifted recently, and TRI reporting due in July 2013 for calendar year 2012 emissions required reporting of H_2S.

While there are no national ambient air quality standards for H_2S, a number of states, especially those with significant oil and gas production, have set standards at the state level. Table 2 summarizes these standards for states under BLM New Mexico State Office jurisdiction.

Table 2. State Ambient Air Quality Standards for H_2S (Skrtic, 2006)

State	Standard	Averaging time	Remarks
Kansas	None		
Oklahoma	200 ppb* (0.2 ppm)	24 hr	
New Mexico	0.010 ppm** (10 ppb)	1 hr	Statewide except Pecos-Permian Basin Intrastate Air Quality Control Region***
	0.100 ppm (100 ppb)	½ hr	Pecos-Permian Basin Intrastate Air Quality Control Region
	0.030ppm (30 ppb)	½ hr	Within municipal boundaries and within five miles of municipalities with population >20,000 in Pecos-Permian Basin AQ Control Region
Texas	0.08ppm (80 ppb)	½ hr	If downwind concentration affects a property used for residential business or commercial purposes
	0.12 ppm (120 ppb)	½ hr	If downwind concentration affects only property not normally occupied by people

*parts per billion **parts per million *** The Pecos-Permian Basin Intrastate Air Quality Control Region is composed of Quay, Curry, De Baca, Roosevelt, Chaves, Lea, and Eddy Counties in New Mexico.

The New Mexico Environment Department (NMED) has no routine monitors for H_2S. However, a one-time study done in 2002 (Skrtic, 2006) sheds some light on the levels which can be expected near oil and gas facilities. These readings are averaged over 3 minute periods so are not comparable with the standard which has longer averaging periods. The monitoring data is presented in Table 3.

Table 3: Summary of Monitoring Data from New Mexico Study (Skrtic, 2006)

Facility type	H_2S concentration measured at monitoring site (ppb)	
	Range	Average
Indian Basin Hilltop, no facility	5 – 8	7
Indian Basin Compressor Station	3 – 9	6
Indian Basin Active Well Drilling Site	7 – 190	114
Indian Basin Flaring, Production, and Tank Storage Site	4 – 1,200	203
Marathon Indian Basin Refining and Tank Storage Site	2 – 370	16
Carlsbad City Limits, near 8 to 10 wells and tank storage sites	5 –7	6
Carlsbad City Limits, Tracy-A	5 – 8	7
Compressor station, dehydrators – Location A	4 –5	4
Compressor station, dehydrators – Location B	2 – 15,000	1372
Huber Flare/Dehydrating Facility	4 – 12	77
Snyder Oil Well Field	2 – 5	4
Empire Abo Gas Processing Plant	1 – 1,600	300
Navajo Oil Refinery	3 – 14	7 - 8

In Oklahoma, routine monitoring downwind of two refineries in Tulsa showed H_2S levels that were within state standards but above normal background levels. In Texas, which has 12 routine monitors, H_2S levels generally ranged from 0.1 to 5 ppb. One monitor at a compressor station, however, showed frequent levels in excess of the state standard of 0.8 ppm (Skrtic, 2006).

In a study by the Fish and Wildlife Service (Lusk, 2010), H_2S was monitored in southeastern New Mexico to determine potential impacts to wildlife. Peak H_2S measurements near oil and gas facilities were generally found to be below 6 ppm but occasional peaks at 33 ppm and 27 ppm were noted near Loco Hills. Away from oil and gas operations, readings were less than 1 ppm. A significantly lower number of birds was found at sites with higher H_2S levels compared with sites undisturbed by oil and gas development where H_2S levels were lower.

AIR QUALITY RELATED VALUES (AQRVS)

AQRVs have been defined as resources that may be adversely affected by a change in air quality. Such resources may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreation resource identified for a particular area. The Federal Land Managers' Air Quality Related Values Workgroup (FLAG) issued a revised Phase 1 report in 2010 (U.S. Forest Service, National Park Service, U.S. Fish and Wildlife Service, 2010). This report was developed as a tool to provide consistent

approaches to the analysis of the effects of air pollution on AQRVs. The FLAG report focuses on three areas of potential impact: visibility, aquatic and terrestrial effects of wet and dry pollutant deposition, and terrestrial effects of ozone. This report is structured to address these same three areas of potential impact.

VISIBILITY

Visibility is of greatest concern in Class I areas which are afforded the highest level of air quality protection by the Clean Air Act. Visibility impairment is a result of regional haze which is caused by the accumulation of pollutants from multiple sources in a region. Emissions from industrial and natural sources may undergo chemical changes in the atmosphere to form particles of a size which scatter or absorb light and result in reductions in visibility.

In 1985, the EPA initiated a network of monitoring stations to measure impacts to visibility in Class I Wilderness Areas. These monitors are known as the Interagency Monitoring for the Protection of Visual Environments (IMPROVE) monitors and exist in some, but not all, Class I wilderness areas. Table 4 shows the Class I areas in the BLM New Mexico State Office area of responsibility and whether they have an IMPROVE monitor and, if not, which monitor is considered representative for that area. There are no Class I areas in Kansas.

Table 4. Class I areas and IMPROVE monitors

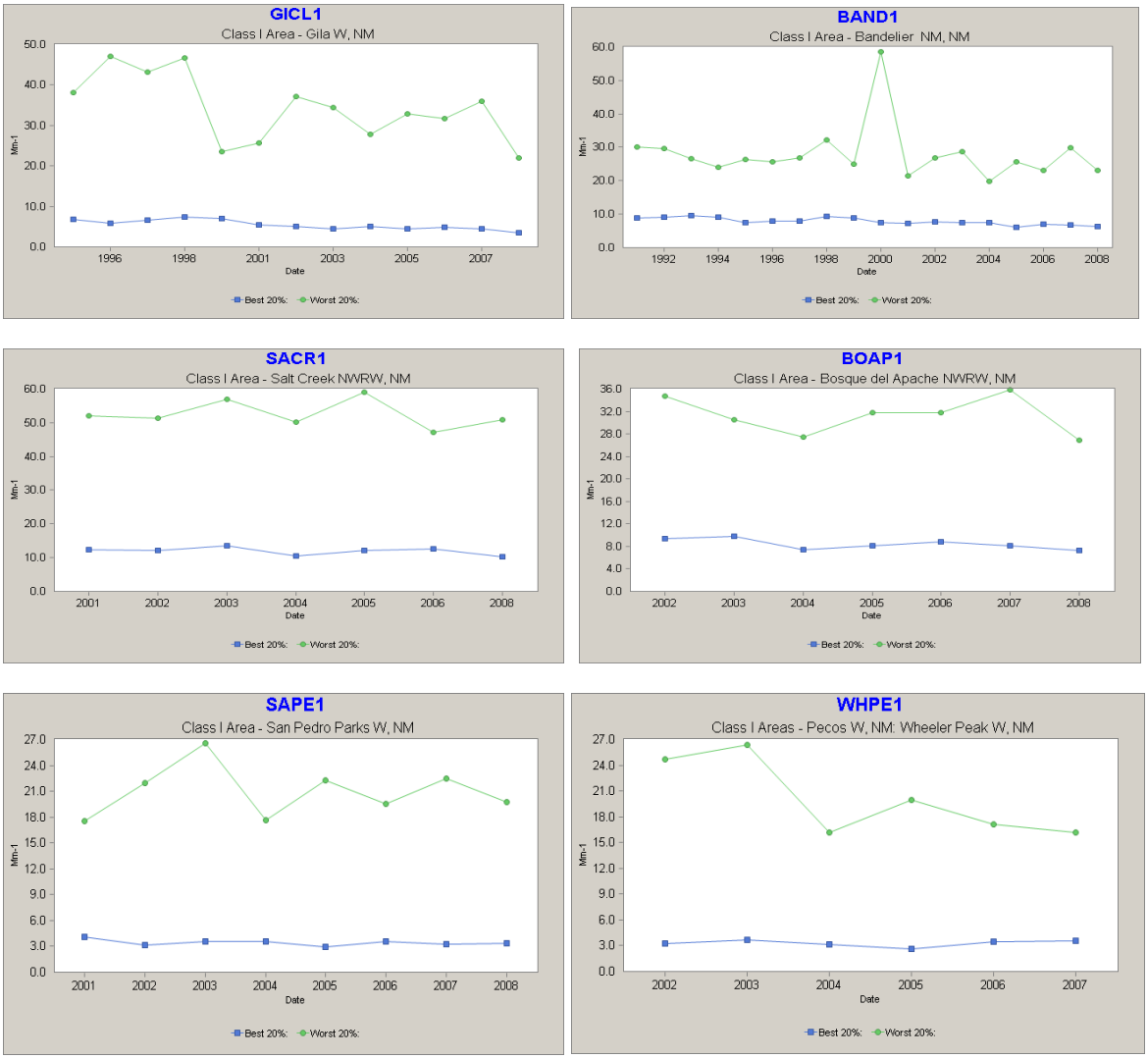
State	Class I Area	Agency	IMPROVE
New Mexico	Bandelier	National Park Service	Yes
	Bosque del Apache	Fish and Wildlife	Yes
	Carlsbad Caverns	National Park Service	Guadalupe Mtns
	Gila	Forest Service	Yes
	Pecos	Forest Service	Wheeler Peak
	Salt Creek	Fish and Wildlife	Yes
	San Pedro Parks	Forest Service	Yes
	Wheeler Peak	Forest Service	Yes
	White Mountain	Forest Service	Yes
Texas	Big Bend	National Park Service	Yes
	Guadalupe Mtns	National Park Service	Yes
Oklahoma	Wichita Mountains	Fish and Wildlife	Yes

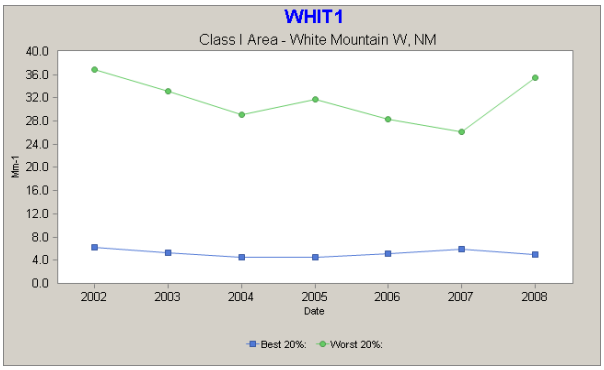
Figure 1 shows visibility extinction trends for each of the IMPROVE monitors in the BLM New Mexico State Office area of responsibility. The top line on each graph is for the 20% worst days and the bottom line is for the 20% best days. Note that peaks such as that seen for Bandelier National Monument in 2000 may be accounted for by the occurrence of large wildfires. A downward sloping line means less reduction of visibility and therefore an improvement. In most cases visibility trends have been flat or

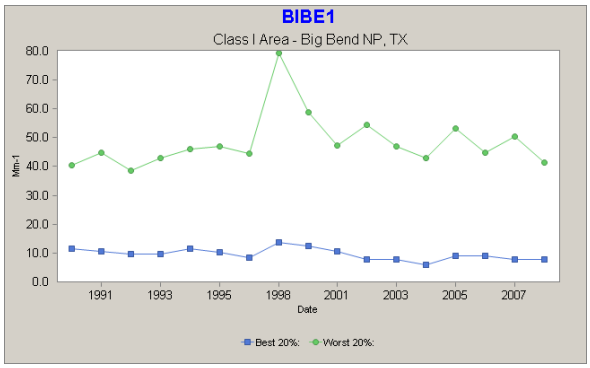
improving. Implementation of Best Available Retrofit Technology (BART) strategies as required under the federal Regional Haze Rule over the next few years should result in further improvements.

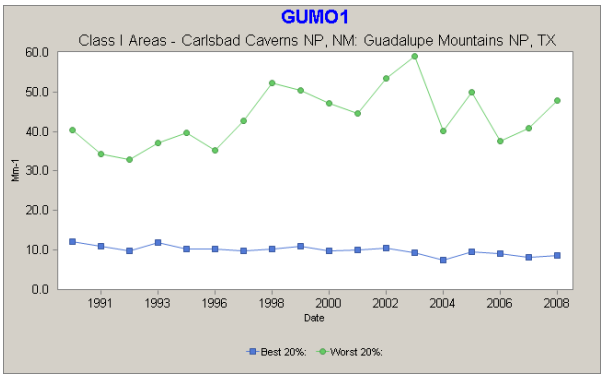
A qualitative discussion of visibility impacts from oil and gas development in the Farmington Resource Management Plan (RMP) concludes that for the scenario modeled, which projected greater development than has occurred; there could potentially be significant impacts to visibility at Mesa Verde National Park, a Class I area in southwest Colorado. Occasional impacts to San Pedro Parks (northern New Mexico) and Weminuche (southern Colorado) Wilderness areas were also thought possible. However, visibility trends shown below for San Pedro Parks, Mesa Verde, and Weminuche indicate that visibility on the best days has been flat to improving and visibility on worst days has shown little change over the period of record.

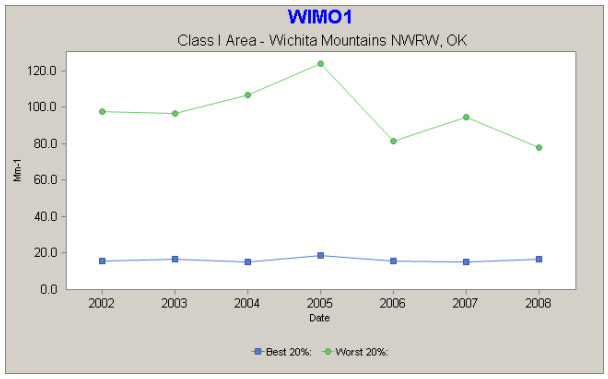
Figure 1. Visibility Extinction in Class I areas (Colorado State University, 2014)







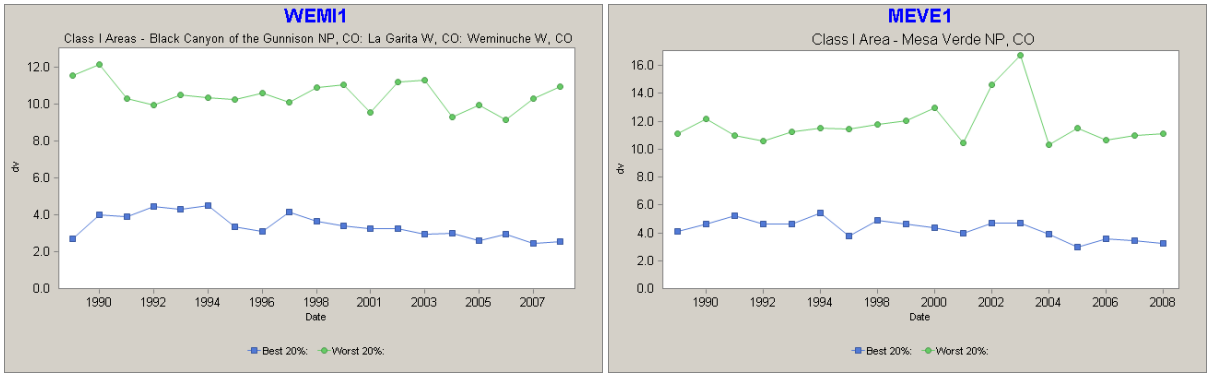




Trend lines for Class I areas affected by sources in Northwestern New Mexico (Figure 2) are similar to trend lines for Class I areas in New Mexico. While visibility on worst days at Guadalupe Mountains National Park may have diminished, a careful analysis of fire activity in the area would be necessary in order to draw conclusions about the cause of some peaks in recent years (Colorado State University, 2014).

A recent study of Air Pollutant Emissions and Cumulative Air Impacts done for the Carlsbad Field Office indicates that pollutants contributing to reductions in visibility are largely coming from outside the region (Applied Enviro Solutions, 2011).

Figure 2. Visibility trends at Class I areas affected by sources in Northwestern New Mexico (Colorado State University, 2014)



The WestJump analysis (ENVIRON International Corporation, Alpine Geophysics, LLC and University of North Carolina, 2013) provides a wealth of information about visibility impairment at Class I areas and the source categories and states that contribute to impairment at each Class I area. There are two pie charts for each of IMPROVE sites in New Mexico, Texas, Oklahoma and Kansas. These pie charts are presented in Appendix F. The first pie chart displays the contributions of the 17 western states by source category and species to visibility impairment for the IMPROVE site for the average of the worst 20% days. The second pie chart displays contributions by the 17 western states to visibility impairment for the IMPROVE site for the average of the worst 20% days. The pie chart data is from the CAMx 2006 36 km state-specific PM source apportionment modeling. The source category codes in the pie charts are:

- CON=controllable emissions (anthropogenic and Rx and Ag fires);
- NAT=natural emissions (biogenic, lightning, sea salt and windblown dust);
- WLF=wildfires.

The species codes in the pie charts are:

- PMC=Crustal
- PEC=elemental carbon
- PNO3=nitrate
- POM=organic PM
- PSO4=sulfate
- SSL=salt
- SSR=Rayleigh
- Soil=Soil

WET AND DRY POLLUTANT DEPOSITION

Deposition of pollutants through precipitation can result in acidification of water and soil resources in areas far removed from the source of the pollution, as well as causing harm to terrestrial and aquatic species. Some pollutants can also damage vegetation through direct or dry deposition. In general, the soils in New Mexico have a high acid neutralizing capacity and surface water is scarce, resulting in minimal impacts in this area. Also, the Acid Rain Program has resulted in greatly reduced levels of the most damaging pollutants. There are currently four wet deposition monitors in New Mexico including Gila Cliff Dwellings, Mayhill, Bandelier National Monument, and Capulin Volcano National Monument. In addition monitors near the border at Mesa Verde and Guadalupe Mountains National Parks may shed some light on conditions in New Mexico. Data can be accessed through the National Atmospheric Deposition Network (NADP) at http://nadp.sws.uiuc.edu/NTN/ntnData.aspx. Wet deposition data is also available for monitoring sites in Kansas, Oklahoma, and Texas at this site.

The EPA has operated the Clean Air Status and Trends Network (CASTNET) since 1991 to provide data to assess trends in air quality, deposition and ecological effects due to changes in air emissions. Sites are located in areas where urban influences are minimal. There are currently no CASTNET observation sites in New Mexico but there are three in Texas and one each in Oklahoma and Kansas. There is a CASTNET site at Mesa Verde National Park in the Four Corners region. National maps of pollutant concentrations can be found at http://www.epa.gov/castnet/javaweb/airconc.html. These maps show that New Mexico and most of the western United States have much lower concentrations of all monitored pollutants than the eastern states and southern California. Nitrates are somewhat elevated in eastern Kansas and eastern Oklahoma but this is likely associated with agricultural activities rather than oil and gas development. The maps also show that the trend over the past 20 years has been for decreases in all pollutants in most areas of the country. As an example, Figure 3 shows particulate nitrate and sulfate levels for 1990 and 2011. Maps of wet deposition data from NADP monitors are also available from the National Atmospheric Deposition Program (National Atmospheric Deposition Program, 2014). Total dry and wet sulfur deposition decreased by 63% from 1990 through 2012 in the eastern U.S. and decreased by 39% from 1996 through 2012 in the west. Total nitrogen deposition decreased by 24% from 1990 through 2012 in the eastern U.S. and decreased by 20% in the western U.S. between 1996 through 2012; however, total nitrogen deposition increased significantly in the eastern U.S. from 2010 to 2011. These trends in deposition levels are discussed in depth in the CASTNET annual report (AMEC Environment and Infrastructure, Inc., 2014).

Figure 3a. Particulate Nitrate 1990(left) and 2014(right)

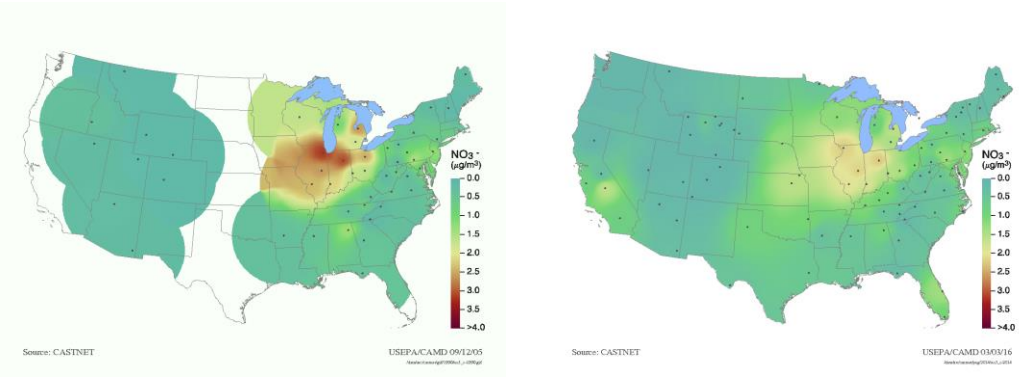
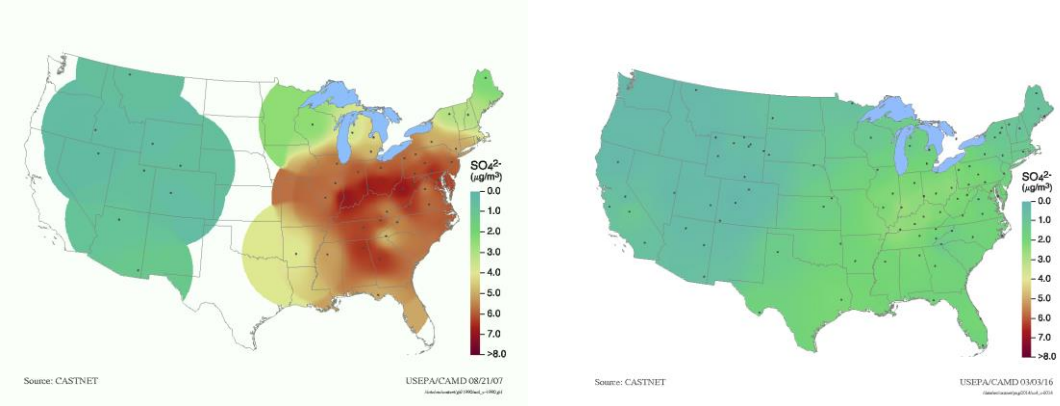


Figure 3b. Particulate Sulfate 1990(left) and 2014(right)



(U.S. Environmental Protection Agency, 2015b)

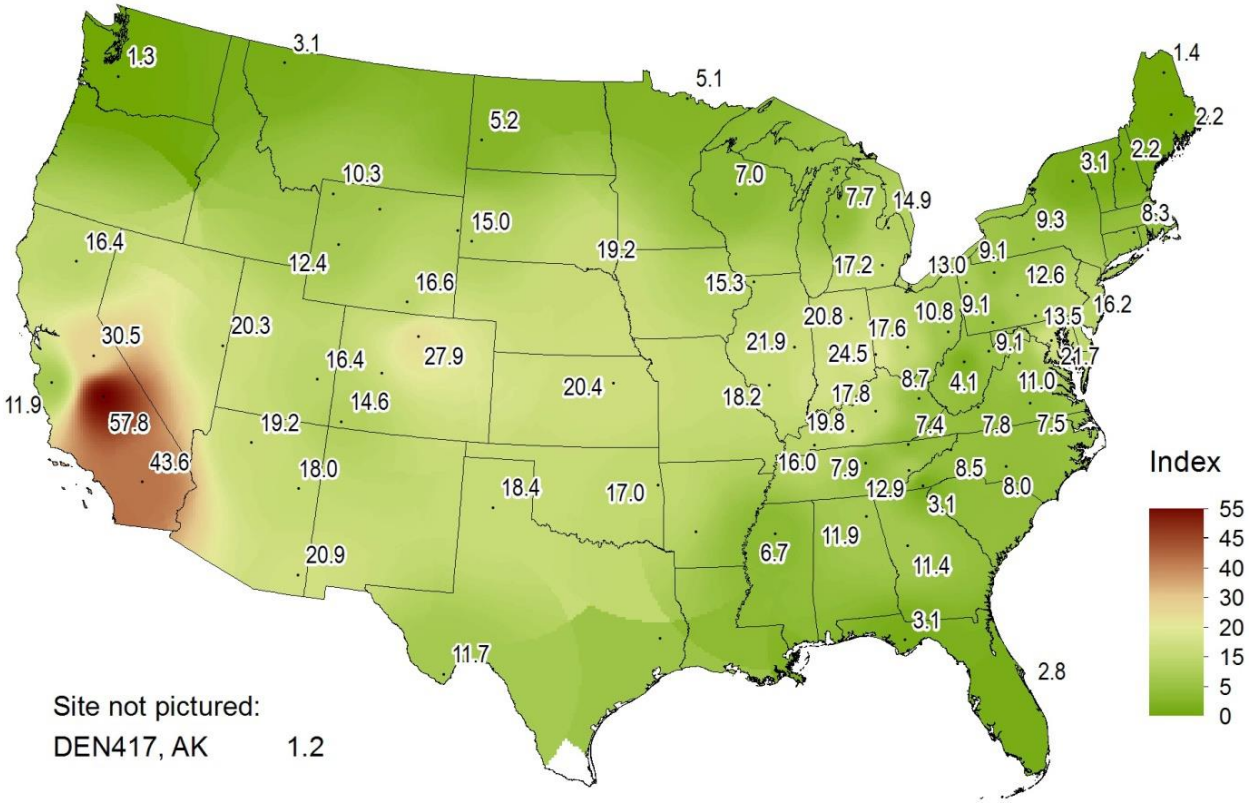
The WestJump analysis (ENVIRON International Corporation, Alpine Geophysics, LLC and University of North Carolina, 2013) provides information about contributing sources to wet and dry depostion at IMPROVE monitoring sites. Pie charts showing the species contributing to nitrogen and sulfur deposition at Class I areas in New Mexico, Texas, Oklahoma, Kansas, Colorado and Arizona are in Appendix G.

TERRESTRIAL EFFECTS OF OZONE

While other air pollutants may also negatively affect vegetation, ozone is recognized as the one most likely to cause damage. Visible damage to leaf cells may be present in the form of spots or dead areas, though damage can be present long before it becomes visible. Decreased growth or altered carbon allocation may also occur. Ponderosa pine and aspen are species known to be sensitive to ozone in the atmosphere (U.S. Forest Service, National Park Service, U.S. Fish and Wildlife Service, 2000).

An index has been developed to express cumulative seasonal impacts to vegetation. This is known as the W126 value. W126 is a cumulative metric that sums weighted hourly ozone concentrations during daylight hours in the summer ozone season. Figure 4 shows national W126 values for 2012 (AMEC Environment and Infrastructure, Inc., 2014). Higher W126 values were measured during 2012 in California, at high terrain sites in the west and at eastern sites with high daily 8-hour ozone concentrations. At high elevations, moderate ozone concentrations persist into the night due to lack of nighttime dry deposition and lack of fresh nitric oxide, both of which typically react with ozone at night to reduce ozone concentrations. The persistent, moderate ozone concentrations at high elevation sites result in higher W126 levels, indicative of steady ozone exposure for vegetation. In 2012, W126 values were higher than in 2011 because of higher ambient ozone concentrations measured in 2012.

Figure 4. W126 values for 2012 in ppm-hour (AMEC Environment and Infrastructure, Inc., 2014)



CLIMATE, CLIMATE CHANGE & GREENHOUSE GASES

Climate is the composite of generally prevailing weather conditions of a particular region throughout the year, averaged over a series of years. Climate averages for 1981-2010, known as the current normal as defined by the World Meteorological Organization, are 30 year averages of temperature and precipitation for the previous three decades and are included in Appendix C.

Climate change is a statistically-significant and long-term change in climate patterns. The terms climate change and "global warming" are often used interchangeably, although they are not the same thing. Climate change is any deviation from the average climate, whether warming or cooling, and can result from both natural and human (anthropogenic) sources. Natural contributors to climate change include fluctuations in solar radiation, volcanic eruptions, and plate tectonics. Global warming refers to the apparent warming of climate observed since the early-twentieth century and is primarily attributed to human activities such as fossil fuel combustion, industrial processes, and land use changes.

Climate change may reinforce (positive feedback) or reduce (negative feedback) an expected temperature increase. A feedback is the process by which changing one quantity results in the amplification or diminishment of another. An example of a positive feedback is the reduced albedo (reflectivity) of land surfaces from the melting of snow and ice. A warming climate is also expected to increase methane release from hydrates, thereby reinforcing the warming trend. There are also feedbacks related to carbon, water, and geochemical cycles. The results of most climate feedbacks are expected to amplify warming, but the exact magnitudes of these effects are difficult to quantify (Intergovernmental Panel on Climate Change (IPCC), 2013).

The natural greenhouse effect is critical to the discussion of climate change. The greenhouse effect refers to the process by which greenhouse gases (GHGs) in the atmosphere absorb heat energy radiated by earth's surface. Water vapor is the most abundant GHG, followed by carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and several trace gases. These GHGs trap heat that would otherwise be radiated into space, causing earth's atmosphere to warm and making temperatures suitable for life on earth. Without the natural greenhouse effect, the average surface temperature of the earth would be about zero degrees Fahrenheit. Water vapor is often excluded from the discussion of GHGs and climate change since its atmospheric concentration is largely dependent upon temperature rather than being emitted by specific sources.

Atmospheric concentrations of naturally-emitted GHGs have varied for millennia and earth's climate fluctuated accordingly. However, since the beginning of the industrial revolution around 1750, human activities have significantly increased GHG concentrations and introduced man-made compounds that act as GHGs in the atmosphere. The atmospheric concentrations of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) have increased to levels unprecedented in at least the last 800,000 years. From pre-industrial times until today, the global average concentrations of CO_2, CH_4, and N_2O in the

atmosphere have increased by around 40%, 150%, and 20%, respectively (Intergovernmental Panel on Climate Change (IPCC), 2013). Table 5 shows the average global concentrations of CO_2, CH_4, and N_2O in 1750 and in 2011. Atmospheric concentrations of GHGs are reported in parts per million (ppm) and parts per billion (ppb).

Table 5. Average global concentrations of greenhouse gases in 1750 and 2011 (Intergovernmental Panel on Climate Change (IPCC), 2013)

Greenhouse Gas	1750 Concentration	2011 Concentration	Increase 1750 – 2011
Carbon dioxide, CO_2	278 ppm	390.5 ppm	40%
Methane, CH_4	722 ppb	1803 ppb	150%
Nitrous oxide, N_2O	270 ppb	324 ppb	20%

Human activities emit billions of tons of carbon dioxide (CO_2) every year. Carbon dioxide is primarily emitted from fossil fuel combustion, but has a variety of other industrial sources. Methane (CH_4) is emitted from oil and natural gas systems, landfills, mining, agricultural activities, and waste and other industrial processes. Nitrous oxide (N_2O) is emitted from anthropogenic activities in the agricultural, energy-related, waste and industrial sectors. The manufacture of refrigerants and semiconductors, electrical transmission, and metal production emit a variety of trace GHGs (including hydrofluorocarbons, HFCs, perfluorocarbons, PFCs, and sulfur hexafluoride, SF_6). These trace gases have no natural sources and come entirely from human activities. Carbon dioxide, methane, nitrous oxide, and the trace gases are considered well-mixed and long-lived GHGs.

Several gases do not have a direct effect on climate change, but indirectly affect the absorption of radiation by impacting the formation or destruction of GHGs. These gases include carbon monoxide (CO), oxides of nitrogen (NO_X), and non-methane volatile organic compounds (NMVOCs). Fossil fuel combustion and industrial processes account for the majority of emissions of these indirect GHGs. Unlike other GHGs, these gases are short-lived in the atmosphere.

Atmospheric aerosols, or particulate matter (PM), also contribute to climate change. Aerosols directly affect climate by scattering and absorbing radiation (aerosol-radiation interactions) and indirectly affect climate by altering cloud properties (aerosol-cloud interactions). Particles less than 10 micrometers in diameter (PM_{10}) typically originate from natural sources and settle out of the atmosphere in hours or days. Particles smaller than 2.5 micrometers in diameter ($PM_{2.5}$) often originate from human activities such as fossil fuel combustion. These so-called “fine” particles can exist in the atmosphere for several weeks and have local short-term impacts on climate. Aerosols can also act as cloud condensation nuclei (CCN), the particles upon which cloud droplets form.

Light-colored particles, such as sulfate aerosols, reflect and scatter incoming solar radiation, having a mild cooling effect, while dark-colored particles (often referred to as “soot” or “black carbon”) absorb radiation and have a warming effect. There is also the potential for black carbon to deposit on snow and ice, altering the surface albedo (or reflectivity), and enhancing melting. There is high confidence that aerosol effects are partially offsetting the warming effects of GHGs, but the magnitude of their effects contribute the largest uncertainly to our understanding of climate change (Intergovernmental Panel on Climate Change (IPCC), 2013).

Our current understanding of the climate system comes from the cumulative results of observations, experimental research, theoretical studies, and model simulations. Climate change projections are based on a hierarchy of climate models that range from simple to complex, coupled with comprehensive Earth System Models. For The IPCC Fifth Assessment Report (AR5) (Intergovernmental Panel on Climate Change (IPCC), 2013), AR5, scientists estimated future climate impacts based on a range of Representative Concentration Pathways (RCPs) for well-mixed GHGs in model simulations carried out under the Coupled Model Intercomparison Project Phase 5 (CMIP5) of the World Climate Research Programme. The RCPs represent a range of mitigation scenarios that are dependent upon socio-economic and geopolitical factors and have different targets for radiative forcing (RF) in 2100 (2.6, 4.5, 6.0, and 8.5 W m^{-2}). The scenarios are considered to be illustrative and do not have probabilities assigned to them.

AR5 uses terms to indicate the assessed likelihood of an outcome ranging from *exceptionally unlikely* (0 – 1% probability) to *virtually certain* (99 – 100% probability) and level of confidence ranging from *very low* to *very high*. The findings presented in AR5 indicate that warming of the climate system is unequivocal and many of the observed changes are unprecedented over decades to millennia. It is *certain* that Global Mean Surface Temperature (GMST) has increased since the late 19th century and *virtually certain* (99 – 100% probability) that maximum and minimum temperatures over land have increased on a global scale since 1950. The globally averaged combined land and ocean surface temperature data show a warming of 0.85°C (1.5°F) (NOAA National Climate Data Center, 2013) (Intergovernmental Panel on Climate Change (IPCC), 2013). Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes. It is *extremely likely* (95 – 100% probability) that human influence has been the dominant cause of the observed warming since the mid-20th century (Intergovernmental Panel on Climate Change (IPCC), 2013).

Additional near-term warming is inevitable due to the thermal inertia of the oceans and ongoing GHG emissions. Assuming there are no major volcanic eruptions or long-term changes in solar irradiance, global mean surface temperature increase for the period 2016 – 2035 relative to 1986-2005 will likely be in the range of 0.3 – 0.7°C (0.5 – 1.3°F). Global mean temperatures are expected to continue rising over the 21st century under all of the projected future RCP concentration scenarios. Global mean temperatures in 2081 – 2100 are projected to be between 0.3 – 4.8°C (0.5 – 8.6°F) higher relative to

1986 – 2005 (Intergovernmental Panel on Climate Change (IPCC), 2013). The IPCC projections are consistent with reports from other organizations (e.g. (NASA Goddard Institute for Space Studies, 2013); (Joint Science Academies, 2005)).

Climate change will impact regions differently and warming will not be equally distributed. Both observations and computer model predictions indicate that increases in temperature are likely to be greater at higher latitudes, where the temperature increase may be more than double the global average. Warming of surface air temperature over land will very likely be greater than over oceans (Intergovernmental Panel on Climate Change (IPCC), 2013). There is also high confidence that warming relative to the reference period will be larger in the tropics and subtropics than in mid-latitudes. Frequency of warm days and nights will increase and frequency of cold days and cold nights will decrease in most regions. Warming during the winter months is expected to be greater than during the summer, and increases in daily minimum temperatures are more likely than increases in daily maximum temperatures. Models also predict increases in duration, intensity, and extent of extreme weather events. The frequency of both high and low temperature events is expected to increase. Near- and long-term changes are also projected in precipitation, atmospheric circulation, air quality, ocean temperatures and salinity, and sea ice cover.

Findings from AR5 and reported by other organizations (NASA Goddard Institute for Space Studies, 2013), (NOAA National Climate Data Center, 2013) also indicate that changes in the climate system are not uniform and regional differences are apparent. Some regions will experience precipitation increases, and other regions will have decreases or not much change. The contrast in precipitation between wet and dry regions and between wet and dry seasons is expected to increase. The high latitudes are *likely* (66 – 100% probability) to experience greater amounts of precipitation due to the additional water carrying capacity of the warmer troposphere. Many mid-latitude arid and semi-arid regions will *likely* (66 – 100% probability) experience less precipitation (Intergovernmental Panel on Climate Change (IPCC), 2013).

Climate change is a global process that is impacted by the sum total of GHGs in the Earth's atmosphere. The incremental contribution to global GHGs from a proposed land management action cannot be translated into effects on climate change globally or in the area of any site-specific action. Currently, Global Climate Models are unable to forecast local or regional effects on resources (Intergovernmental Panel on Climate Change (IPCC), 2013). However, there are general projections regarding potential impacts to natural resources and plant and animal species that may be attributed to climate change from GHG emissions over time; however these effects are likely to be varied, including those in the southwestern United States (Karl, 2009). For example, if global climate change results in a warmer and drier climate, increased particulate matter impacts could occur due to increased windblown dust from drier and less stable soils. Cool season plant species' spatial ranges are predicted to move north and to higher elevations, and extinction of endemic threatened or endangered plants may be accelerated. Due to loss of habitat or competition from other species whose ranges may shift northward, the populations

of some animal species may be reduced or increased. Less snow at lower elevations would likely impact the timing and quantity of snowmelt, which, in turn, could impact water resources and species dependent on historic water conditions (Karl, 2009).

In the region encompassing southern Colorado and New Mexico, average temperatures rose just under 0.7 degrees Fahrenheit per decade between 1971 and 2011, which is approximately double the global rate of temperature increase (Rahmstorf, 2012). These rates of warming are unprecedented over the past 11,300 years (Marcott, 2013). Climate modeling suggests that average temperatures in this region may rise by 4-6 degrees Fahrenheit by the end of the 21st century, with warming increasing from south to north. By 2080-2090, the southwestern U.S. will see a 10-20% decline in precipitation, primarily in winter and spring, with more precipitation falling as rain (Cayan, 2013).

In a recent report, the Bureau of Reclamation (Bureau of Reclamation, Sandia National Laboratories, U.S. Army Corps of Engineers, 2013) made the following projections through the end of the 21st century for the Upper Rio Grande Basin (Southern Colorado to central southern New Mexico) based on the current and predicted future warming:

- There will be decreases in overall water availability by one quarter to one third.
- The seasonality of stream and river flows will change with summertime flows decreasing.
- Stream and river flow variability will increase. The frequency, intensity and duration of both droughts and floods will increase.

Texas, Oklahoma and Kansas are part of the Great Plains region, which will see increases in temperatures and more frequent drought in the future. Temperature increases and precipitation decreases will stress the region's primary water supply, the Ogallala Aquifer. Seventy percent of the land in this area is used for agriculture. Threats to the region associated with climate change include:

- Pest migration as ecological zones shift northward;
- Increases in weeds; and
- Decreases in soil moisture and water availability (U.S. Environmental Protection Agency, 2013b).

The IPCC concludes in AR5 that "cumulative emissions of CO_2 largely determine global mean surface warming by the late 21st century and beyond. Most aspect of climate change will persist for many centuries even if emissions of CO_2 are stopped. This represents a substantial multi-century climate change commitment created by past, present and future emissions of CO_2" (Intergovernmental Panel on Climate Change (IPCC), 2013). Increasing concentrations may accelerate the rate of climate change in the future.

METHODOLOGY AND ASSUMPTIONS FOR ANALYSIS OF AIR RESOURCES

Air resource impacts can be analyzed on a number of different levels. First and most basic is to compare monitored pollutant levels with National Ambient Air Quality Standards. This generally applies only to criteria pollutants and provides a basis for determining whether the emissions of any specific pollutant are significant in a local area. Secondly, and necessary before further analysis can be done is an estimate of actual emissions, or an emissions inventory. This may be done for all emissions in a geographic area and for a project to provide a comparison. EPA completes a National Emissions Inventory at the county level every three years which provides a baseline for determining whether project emissions will cause a substantial increase in emissions or materially contribute to potential adverse cumulative air quality impacts. Finally, if impacts are anticipated to be significant, it may be necessary to apply air quality modeling to analyze the extent and geographic distribution of impacts. Further discussion of calculators used for emissions inventory and modeling which may be required for air resource analysis is presented in the following sections. Also, discussed below are methodologies appropriate to GHG analysis which may be very different from those appropriate for air pollutant analysis.

CALCULATORS

Emissions calculators were developed by air quality specialists at the BLM National Operations Center in Denver, Colorado. The calculators use an Excel spreadsheet for computation and are based on emissions factors from EPA and the American Petroleum Institute (API). The calculators were quality assured and improved by the URS Corporation under contract with the BLM. Methodology for computing greenhouse gases is documented in ***The Climate Change Supplementary Information Report for the Montana, North Dakota and South Dakota Bureau of Land Management*** (URS Corporation, 2010). More recently, Kleinfelder West, Inc. developed a calculator for a representative oil and gas well in the western United States (Kleinfelder West, Inc., 2013). Other air pollutant computations have not yet been described in a published document but are based on methods recommended in the EPA publication AP-42 *Compilation of Air Pollutant Emissions Factors* (U.S. Environmental Protection Agency, 1995), (U.S. Environmental Protection Agency, 2006).

The calculators account for a number of variables, including access and construction requirements, equipment and other infrastructure needs, and expected production volumes. Because the algorithms used by the calculators to quantify emissions are based on averages and numerous assumptions must be made about construction, the calculators provide an approximation of emissions levels. Actual project emissions may be greater or less than those projected by the calculators. Emissions for oil and gas development assume that wells will be hydraulically fractured; if a well is not fractured, emissions will be less than calculated.

The BLM in NM has modified the calculators and assumptions for use in analyzing a single well and to more closely represent oil and gas wells in the state of New Mexico; specifically the San Juan and Permian Basins. However, it must be understood that the calculators were originally designed to make estimations of emissions at the RMP level which would result in some averaging and smoothing of assumptions. At the single well level, the uncertainty in emissions projections increases substantially.

The BLM has determined that well production typically declines over time and has assumed that declining production would result in reduced emissions over time. A production history may vary from a straight line to a hyperbolic curve. The object of decline curve analysis is to model the production history. Assuming a certain abandonment pressure or gas rate, the decline curve is used to determine the productive life of the well. Well life can vary from a few years to many decades depending on the reservoir and the year it was drilled. Production is also dependent on the price of oil and gas. Since initial development in the San Juan Basin in the 1920s, all reservoirs have had significant reservoir pressure declines. Subsequent infill drilling will encounter reduced pressure reservoirs with limited well life spans compared to wells drilled earlier in the development of the field.

It should be noted that the calculations are based on recently drilled wells and tend to overestimate the average emissions over the lifetime of the well. It is not possible to estimate the lifespan of an individual well, nor is the calculator able to incorporate the decline curve into results, so we have computed one-time (construction, completion, workover and reclamation) emissions and annual (operations and maintenance) emissions. However, the annual emissions do not take into account the declining production rates over the lifetime of the well.

Uncertainties Of GHG Calculations

Although a NEPA document may present a quantified estimate of potential GHG emissions associated with reasonably foreseeable oil and gas development, there is significant uncertainty in GHG emission estimates due to uncertainties with regard to eventual production volumes and variability in flaring, construction, and transportation.

Also, there is uncertainty with regard to the net effects of reasonably foreseeable oil and gas development on climate – that is, while BLM actions may contribute to the climate change phenomenon, the specific effects of those actions on global climate are speculative given the current state of the science. Inconsistencies in the results of scientific models designed to predict climate change on regional or local scales limits the ability to quantify potential future impacts of decisions made at this level and determining the significance of any discrete amount of GHG emissions is beyond the limits of existing science at the present time.

ASSUMPTIONS

As mentioned above, the calculators account for a number of variables or inputs that are used to calculate the overall emissions of the different stages of oil and gas development. At the time of an Application for Permit to Drill, not all of these variables may be known. In order to populate the calculators with the different variables, the BLM Carlsbad Field Office (CFO) and the Farmington Field Office (FFO) each developed a set of assumptions pertaining to development in their respective areas. These assumptions address variables such as well depth, production, road development/maintenance, travel to and from well sites, construction times, and need for workovers. The following sections summarize the assumptions made for each field office area in order to populate the calculators.

ASSUMPTIONS - FARMINGTON FIELD OFFICE

There are several geologic formations within the FFO boundary that are known to produce natural gas. The Fruitland is the shallowest routinely produced formation at approximately 2,000 ft. deep. The Dakota is the deepest formation routinely-produced at approximately 6,000 ft. deep. The Mancos Shale formation is approximately 2,500 feet deep. Several formations produce various amounts of water during the production phase of the well. The preferred method of disposing of the produced water is via an injection well drilled into the geologically isolated Entrada formation, which is approximately 7,500 ft. deep. Although wells are not drilled to these precise depths, these generalized depths were used for the purpose of estimation in the emissions calculator.

Between 2015 and 2030, it is estimated that most of the oil and gas drilling in FFO will be within the Mancos Shale formation. The formation is thought to contain gas on the northern end (southern Colorado and northwestern New Mexico) and oil on the southern end (towards Gallup and Grants, NM). Due to unfavorable natural gas prices in the near-term, no gas well development in the Mancos Shale formation is expected until at least 2019. Starting in 2019, it is estimated that approximately 100-200 gas wells could be drilled per year. It is likely that central collection and shipping facilities for oil will be developed, too. Oil well development in the Mancos Shale formation is expected to proceed at 100-200 wells per year, although little development is currently occurring due to unfavorable oil prices. Recent oil well drilling has used horizontal rather than vertical wells.

BLM specialists and engineers were consulted to develop a range of values to insert into the calculator to estimate the emissions from construction, completion, interim reclamation, annual operation, and final reclamation. Pad construction, interim reclamation, and final reclamation processes are generally the same across the basin. The range of values was designed to address the requirements of about 95% of the wells developed in the San Juan Basin. Unforeseen or unpredictable events may cause approximately 5% of wells to fall outside of the range.

The calculator includes construction of a “frac pond”, as future wells in the region will most likely be accomplished with hydraulic fracturing. The calculator has options for diesel-fired or natural gas-fired drill rigs. More commonly in 2014 in the region, drill rigs were diesel-fired. Many of the well pads have associated man camps where drilling personnel are housed during well drilling. Since most pads will now accommodate more than one well, the man camps allow employees to avoid commuting during the time the wells on the pad are drilled.

The ancillary activities associated with the production phase of a well such as workovers, road maintenance, and road traffic are somewhat difficult to predict. Calculations for Mancos Shale drilling recently have assumed one well workover per year. Existing gas wells in the FFO area do not require workover on a regular schedule. Three to six years between workovers is typical, and the nature of the work required during a workover is variable.

FFO and the oil and gas industry have established a road committee to identify collector roads (main travel corridors) and have established procedures to maintain collector roads as necessary. However, no regular maintenance schedule exists. Most new wells are drilled along existing resource roads that are not covered by the road committee and are maintained as needed. Although road maintenance within the FFO varies, a reasonable assumption is that the resource roads will be maintained once a year. The average length of new road required to drill a new well during the past two years has been 800 ft. Emissions are calculated based on this average assuming that an 800 ft. resource road is maintained once a year and the maintenance work would require about 6 hours of work.

The majority of producing wells in the San Juan Basin utilize remote telemetry powered by solar panels to transmit well production data to centralized office locations. While the frequency of well site visits is not predictable, the need for well site visits during the production phase of the well is greatly reduced by the telemetry systems. Typically, a field technician will drive a light truck and will visit multiple wells per trip along an established service route. To estimate the miles required for each site visit, an additional 4.5 miles of travel along an existing driving route was added to the typical 800 ft. of new road for a total of 5 miles. Emissions are calculated for weekly visits during the year for a light truck. For various servicing needs, heavy duty vehicles over 8,500 lbs. gross vehicle weight rating (U.S. Environmental Protection Agency, 2015c), are required on-site during drilling and workovers. Heavy duty vehicles typically do not visit multiple sites per day. Emissions are calculated for driving 50 miles round trip for five trips per year.

The average San Juan Basin gas well produces at a rate of 100 mcfd (thousand cubic feet per day). For analysis purposes, the initial production rate is assumed to be 100 mcfd. The volume of gas and oil is normally the greatest following the completion of the well. Oil and gas production rates decline as a function of time, reservoir pressure drop, or the changing relative volumes of the produced fluids.

The FFO RMP (U.S. Department of Interior Bureau of Land Management, 2003) addressed air quality based on the Air Quality Modeling Analysis Technical Report prepared by Science Applications International Corporation (SAIC, 2003). The 2003 FFO RMP modeling is considered here because it was used to characterize air quality for the purpose of land use planning, and this environmental assessment tiers to the 2003 FFO RMP. The 2003 SAIC modeling was based on the highest level of oil and gas development proposed based on the RFD and identified a potential for exceeding the NAAQS for NO_2. The alternative selected for the RMP proposed a lower level of development than that modeled. Lower levels of development and NO_x limits placed on engines have resulted in lower impacts than were modeled.

ASSUMPTIONS – CARLSBAD FIELD OFFICE

The CFO area of responsibility contains 28 different geologic zones that produce oil, natural gas and water. The complex geology, variety of drilling techniques used (horizontal, vertical), uncertainty of production, and variation of the drilling time and equipment required makes it difficult to approximate the emissions for a proposed well. In order to provide a basis for extrapolation, the CFO selected a random sample of seventy wells out of a population of 1836 wells drilled within the last 4 years (2007-2010). These recently drilled wells were selected to incorporate the latest technology, the latest trends in oil and gas development, and the most recent production data. This sample of newer wells will overestimate average annual production (and therefore emissions) as production drops with the age of the well. The sample size was selected to insure that it was representative of 95% of the recently drilled wells.

The 70 wells were reviewed to ensure accurate production data was available and to eliminate older wells that had been re-drilled into a new formation. Sixty-eight wells remained after the review. This was still a sufficient sample size to ensure statistical accuracy, so no additional wells were selected. The annual production values for oil, gas, and water, length of road constructed, well pad size and travel distances to reach the well from the nearest town were calculated for each well. The lowest, highest, and mean values were then calculated for each parameter and used to create three emissions scenarios (maximum, minimum, and average). These values represent the maximum, minimum and average emissions for 95% of the new wells in the CFO. Unforeseen or unpredictable events may cause 5% of wells to fall outside of the range. Because the minimum scenario has no production, it can be used to estimate the emissions from a salt-water disposal well.

Other values required for the calculator were conservatively estimated by BLM resource staff. It is not possible to predict the exact amount of time or equipment required for the development and operation of a well in the Permian Basin due to the varied geological formations, numerous operators and other variables. Therefore, BLM specialists and engineers were consulted to develop a range of values to insert into the calculator to estimate the emissions from construction, completion, interim reclamation,

annual operation, and final reclamation. The range was designed to include the requirements of 95% of the wells that may be developed in the Permian Basin. Where no information was available, the default values from the calculator were used. The calculator will be updated as additional information becomes available.

The ancillary activities associated with the production phase of a well such as workovers, road maintenance, and road traffic are difficult to predict. Oil and gas wells in the CFO do not require workover on a regular basis and when these activities occur, they generally are not reported to the BLM. Three to six years between workovers is routine, and the nature of the work required during a workover is variable. It is assumed that any gas released during the completion process will be flared. The calculator assumes 100 percent combustion efficiency.

The emissions calculator can be used to estimate PM as a result of construction and drilling activities related to pad building and road traffic. The amount of PM emissions depends on the length, surface condition; soil types traversed, and soil moisture conditions of the road to the site. Because site visit frequencies vary and are difficult to predict, varying numbers of site visits were input into the calculator, which had almost no impact on the total tons of PM emitted. Most gas wells in the Permian Basin utilize remote telemetry powered by solar panels to transmit well production data to centralized office locations. The need for well site visits during the production phase at these wells is greatly reduced. Oil wells require site visits, and the frequency of well visits is not predictable.

While the frequency of well site visits is not predictable, the need for well site visits during the production phase of the well is greatly reduced by the telemetry systems. Typically, a field technician will drive a light truck and will visit multiple wells per trip along an established service route. It was estimated that an average trip distance consists of two miles 3 times per week. This information is used in calculating the annual operation emissions. Heavy trucks are required on site less often than light trucks for various servicing needs. Heavy trucks typically do not visit multiple sites per day. Distances to the wells were determined from the statistical sample including the total distances traveled on dirt and paved roads to reach the well from the nearest town (Carlsbad, Artesia, Hobbs, etc.). Emissions include maintenance and inspection of the well. Reclamation of the well site and road will be conducted when the well has finished producing and is plugged and abandoned. Emissions from reclamation of the well pad and road are also estimated.

County roads in the CFO have established procedures for maintenance but no regular maintenance schedule exists. Most new wells are drilled along oil and gas lease roads that are only maintained by oil and gas operators as needed. Therefore, road maintenance within the CFO is not predictable. The average length of new road required to drill a new well during the past four years based on the random sample has been 570 ft. Emissions are calculated based on this average assuming that a 570 ft. resource road is maintained once a year.

Maximum, minimum and average emissions for construction, completion/recompletion, workover, annual operations, annual road maintenance, and reclamation have been calculated and are presented in project APD EAs. Note that these estimates are based on hypothetical scenarios and it is unlikely that the maximum emissions scenario would ever occur.

AIR QUALITY MODELING

The calculators may be considered a type of model in that they use emissions factors, mathematical algorithms, and assumptions to arrive at some approximation of reality. However, their primary purpose is to compute an emissions inventory which is a necessary ingredient to any modeling effort.

Traditional air quality modeling generally falls into three categories. 1) Near-field dispersion modeling is applied to criteria pollutants, HAPs and AQRVs where a small to medium number of sources are involved to cover an area within 50km of a proposed project. 2) Far-field or transport modeling is used to provide regional assessments of cumulative and incremental impacts at distances greater than 50km. 3) Photochemical modeling is necessary for large scale projects with a large number of sources or with complex issues including ozone and secondary particulate impacts. An Air Quality Memorandum of Understanding (MOU) signed by the Department of Agriculture, Department of the Interior, and Environmental Protection Agency contains an Appendix which describes the air quality models available and their advantages, disadvantages and applications. The MOU and Appendix are included as Appendix E of this document.

METHODOLOGY FOR ANALYSIS OF GHGS

Air quality models used to predict concentrations and transport of air pollutants are not applicable to well-mixed, long-lived greenhouse gases (GHGs) which impact the atmosphere on a global scale. Global Climate Models cannot currently be downscaled to accurately relate GHG emissions to regional or local-scale impacts. The GHG emissions data derived from analytical tools (such as emission calculators) may be used to compare project level emissions with state, national and global emissions. However, such a comparison may not always be useful information since project level emissions are often orders of magnitude less than national level emissions. Comparisons of GHG emissions among project alternatives and an analysis of the resiliency of different project alternatives to the effects of climate change may provide more useful information. When modeling and analyzing GHG emissions, the primary sources of GHG emissions include:

- Carbon dioxide (CO_2) is generated by the combustion of fossil fuels used to power the various engines required for the drilling and production of natural gas. These produce CO_2 in quantities that vary depending on the age, types, and conditions of the equipment as well as the targeted formation, locations of wells with respect to processing facilities and pipelines, and other site-specific factors. Estimated emissions for CO_2 are obtained from the calculator for the drilling and

operational phases of the well, as well as for other ancillary aspects of well development. These values include emissions from combustion engines used to construct and maintain the well.

- Methane (CH_4) releases from gas well development result from venting of natural gas during the well completion process, actuation of gas operated valves during well operations, and fugitive gas leaks along the infrastructure required for the production and transmission of gas. This is a major source of global CH_4 emissions. These emissions have been estimated for various aspects of the energy sector, and starting in 2011, producers are required under 40 CFR 98, to estimate and report their CH_4 emissions to the USEPA. Estimated emissions for CH_4 are obtained from the calculator. These values include emissions from combustion engines used to construct and maintain the well. No methane emissions are predicted from ancillary construction operations.

Greenhouse gases (GHGs) are included in the emission calculator and predictable GHG emissions are reported. The predicted greenhouse gas emissions are compared to the baseline statewide greenhouse gas emissions as reported in the Inventory of New Mexico Greenhouse Gas Emissions: 2000-2013 (New Mexico Environment Department, 2016).

BLM has also used a top down approach to estimate greenhouse gas emissions based on EPA's national Greenhouse Gas Emissions Inventory (U.S. Environmental Protection Agency, 2015d) and local oil and gas production as a percentage of U.S. production.

CUMULATIVE EFFECTS

The CEQ regulations define cumulative effects as "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such actions" (40 CFR 1508.7; (U.S. Department of Interior Bureau of Land Management, 2008)).

CURRENT AND FORESEEABLE CONTRIBUTIONS TO CUMULATIVE EFFECTS

A list of major sources (sources emitting more than 100 tons/year of CO, VOC, NO_x, SO_2, $PM_{2.5}$, or PM_{10}) in New Mexico, Kansas, Oklahoma, and Texas can be found in Appendix D. Any of these sources may contribute to cumulative effects within a local or regional context. All major sources in the figures represent emissions from the National Emission Inventory 2014, with the exception of CO, in which the latest available data was from 2011.

More specific information about sources in New Mexico's oil and gas producing regions which have the greatest impacts on air quality and greenhouse gases is included below. Figure 5 shows maps of major sources in the four-state area for pollutants of concern. Similar maps for the individual states are included in Appendix D.

Figure 5a. Major Emissions Sources (CO), New Mexico, Kansas, Oklahoma and Texas (U.S. Environmental Protection Agency, 2016d)

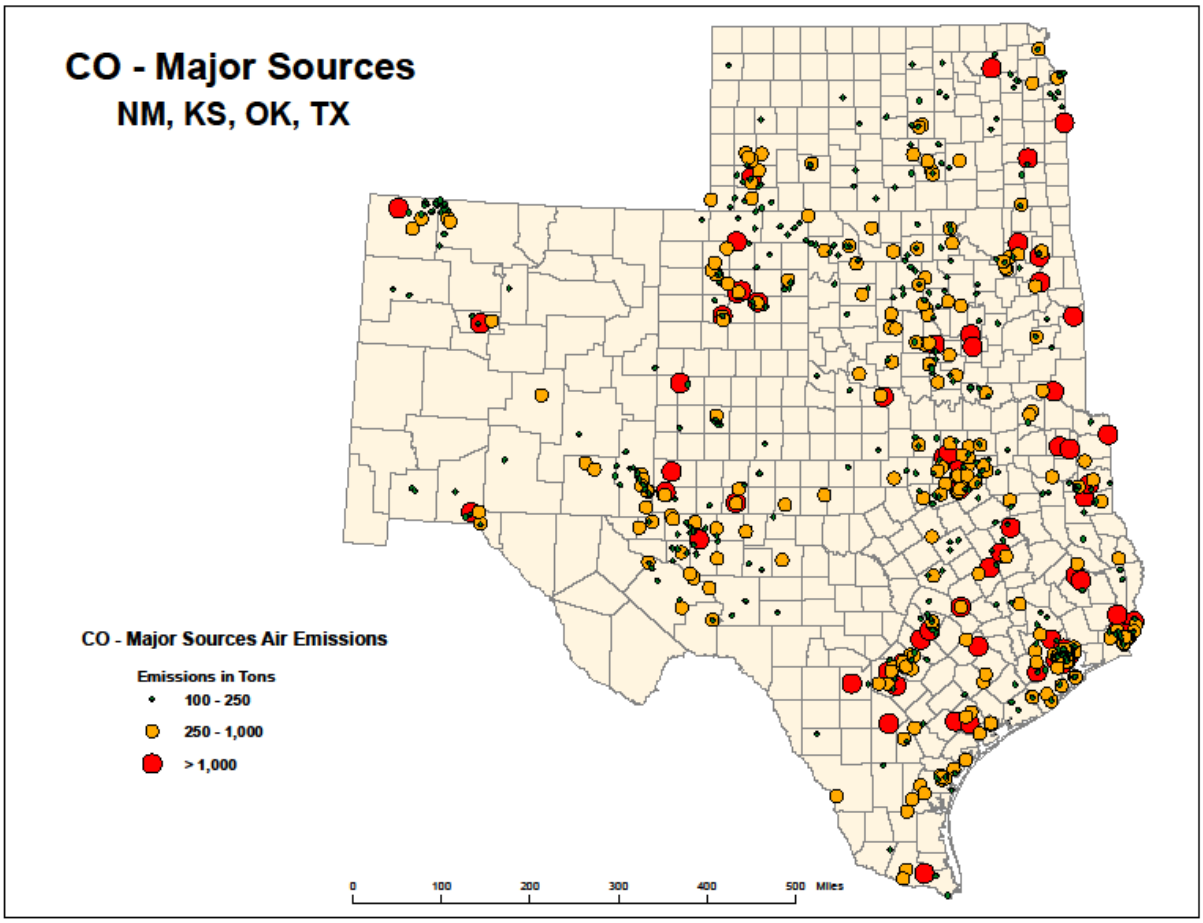


Figure 5b. Major Emissions Sources (NOx), New Mexico, Kansas, Oklahoma and Texas (U.S. Environmental Protection Agency, 2016d)

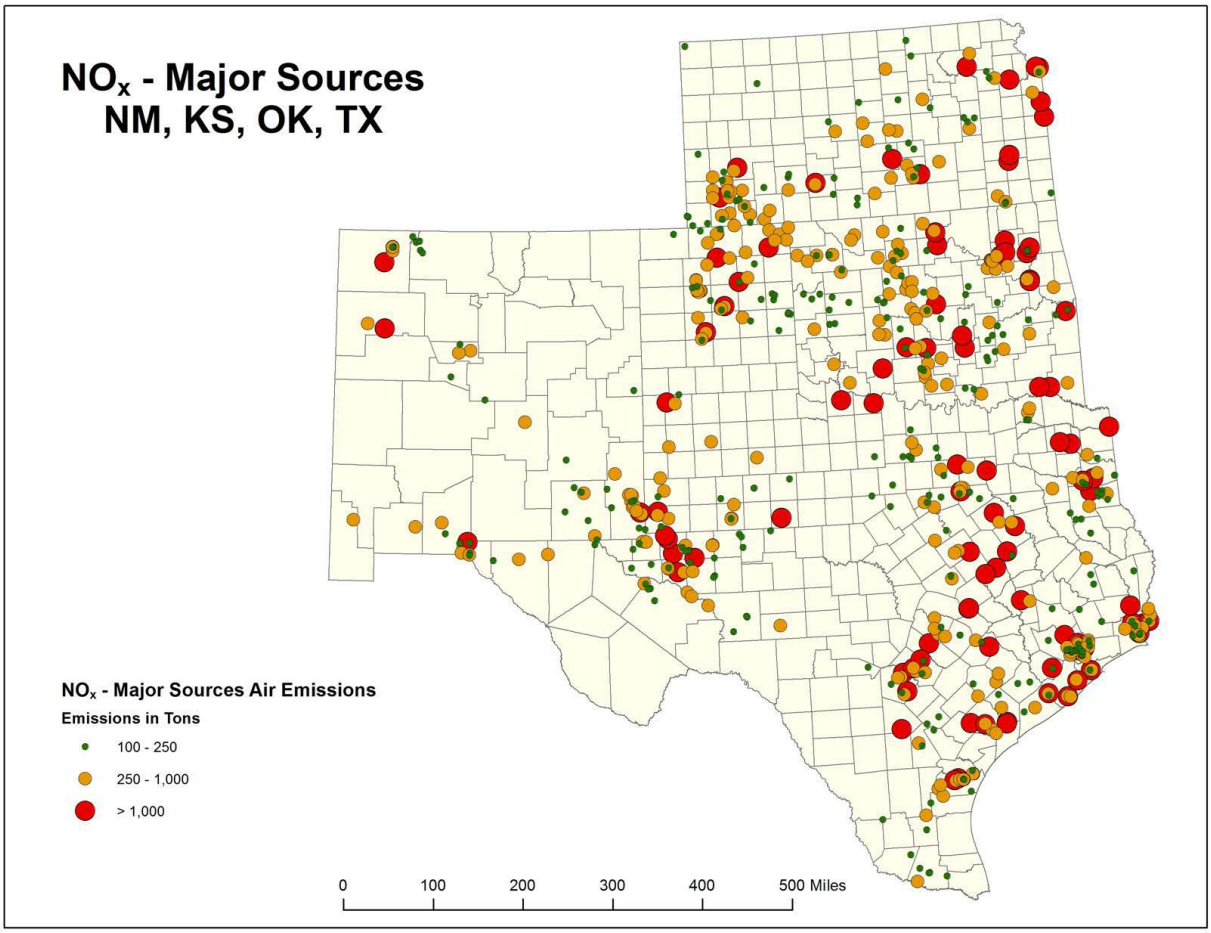


Figure 5c. Major Emissions Sources ($PM_{2.5}$), New Mexico, Kansas, Oklahoma and Texas (U.S. Environmental Protection Agency, 2016d)

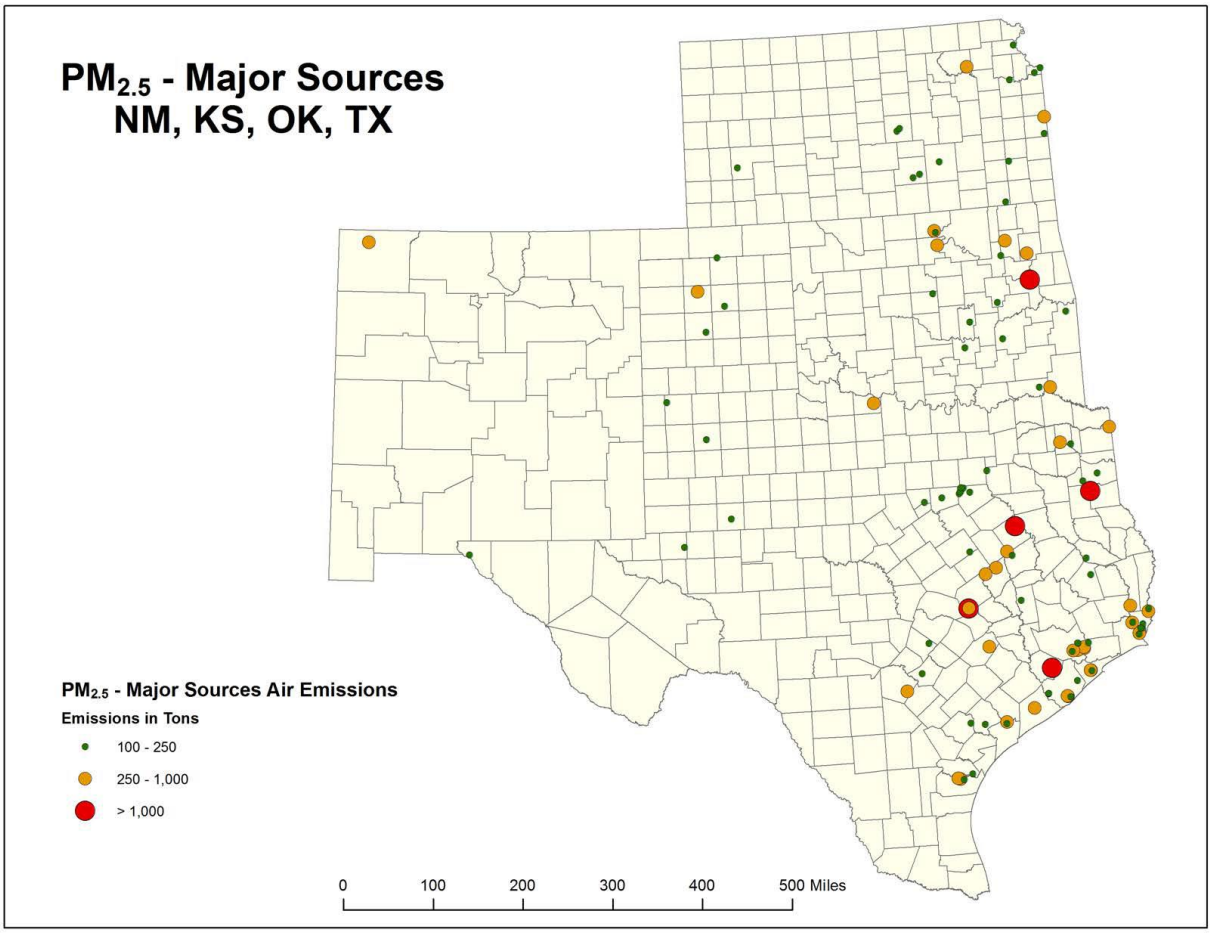


Figure 5d. Major Emissions Sources (PM_{10}), New Mexico, Kansas, Oklahoma and Texas (U.S. Environmental Protection Agency, 2016d)

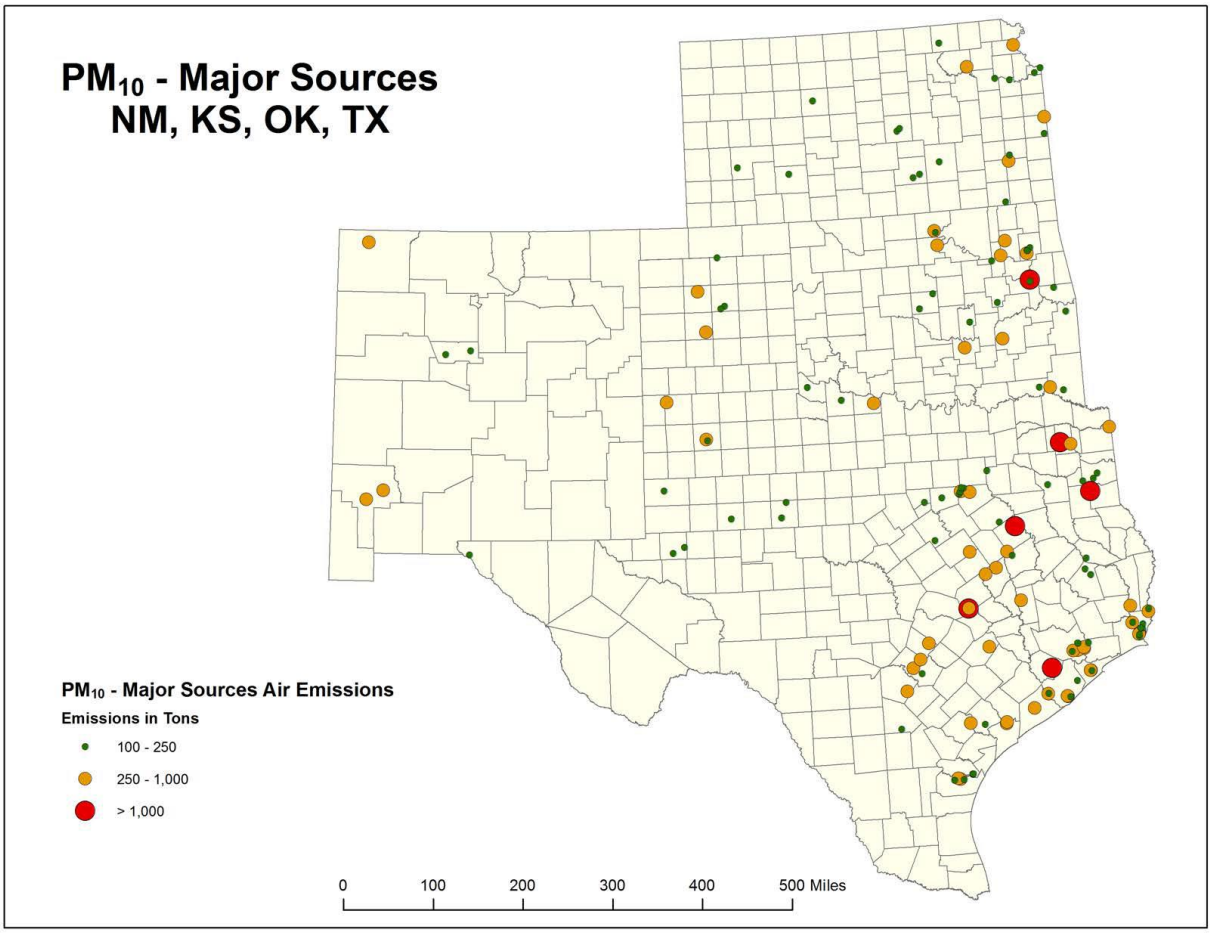


Figure 5e. Major Emissions Sources (SO_2), New Mexico, Kansas, Oklahoma and Texas (U.S. Environmental Protection Agency, 2016d)

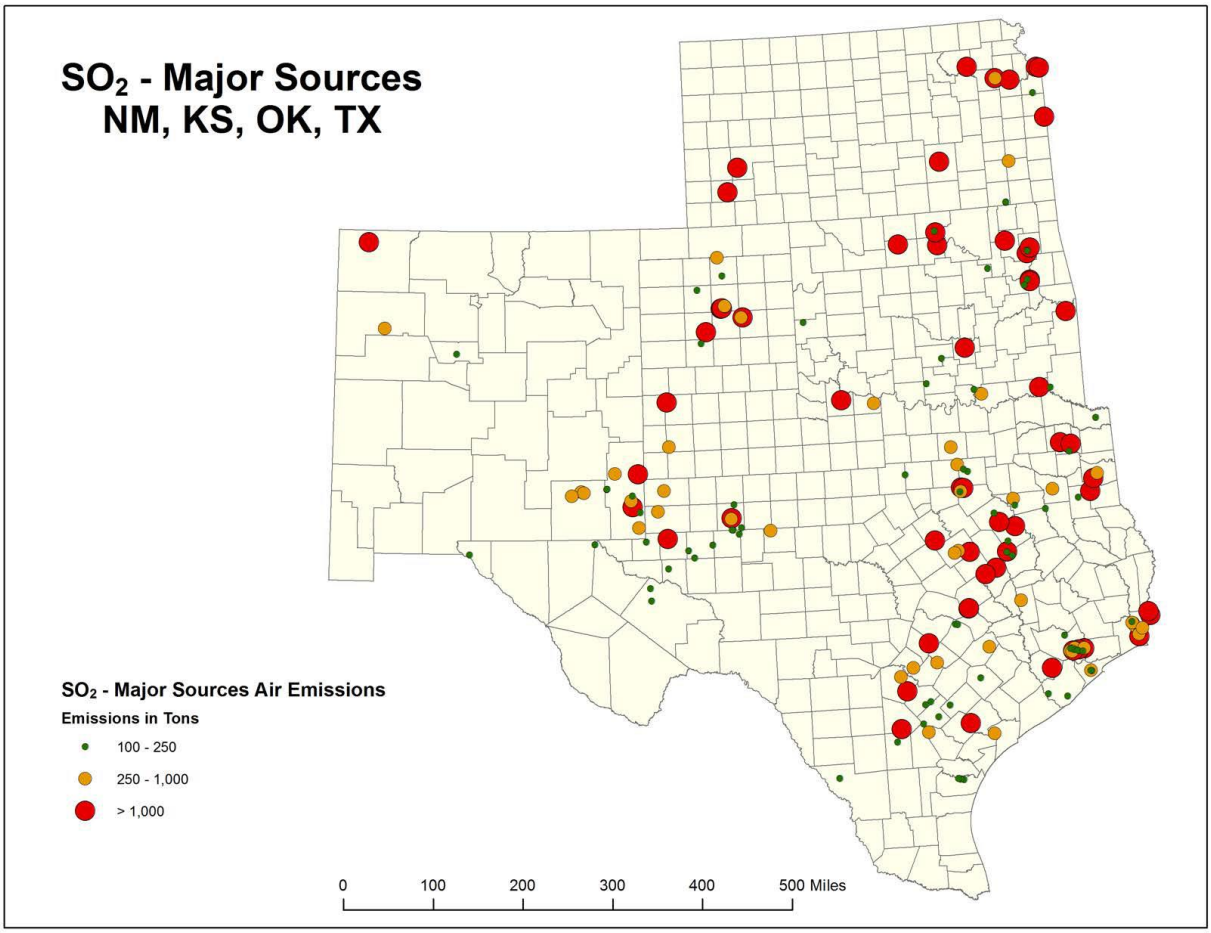
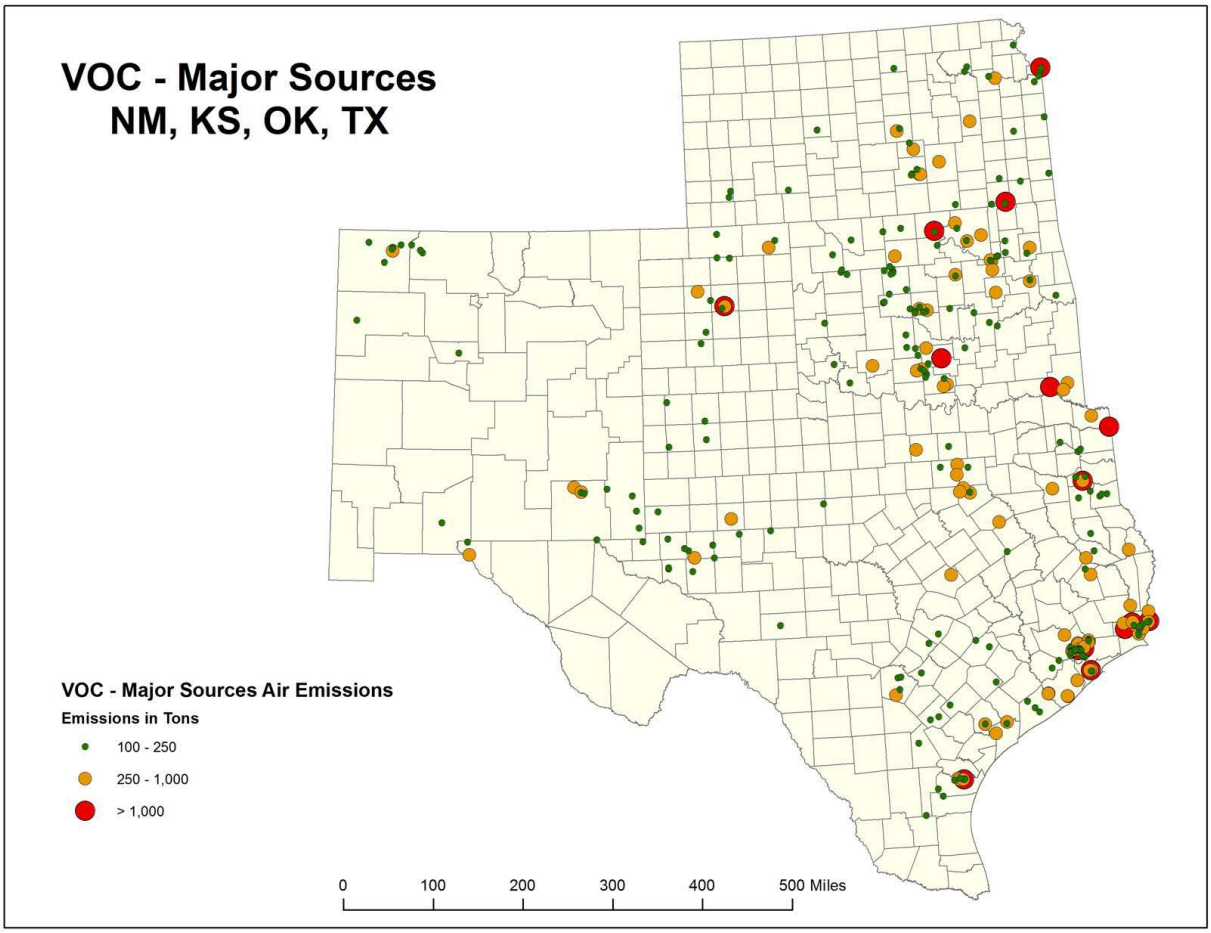


Figure 5f. Major Emissions Sources (VOC), New Mexico, Kansas, Oklahoma and Texas (U.S. Environmental Protection Agency, 2016d)



ELECTRICAL GENERATING UNITS

There are two coal-fired electrical generation units (EGUs) in the Four Corners area: the San Juan Generating Station, located 15 miles west of Farmington, NM; and the Four Corners Power Plant, located on Navajo Nation land in Fruitland, NM. These EGUs are the primary source of several criteria air pollutants in the FFO area, including SO_2 (85%), NO_x (41%), and $PM_{2.5}$ (3%) (U.S. Environmental Protection Agency, 2016d). EGUs are responsible for 31% of New Mexico GHG emissions (New Mexico Environment Department, 2016) and 31% of U.S. GHG emissions (U.S. Environmental Protection Agency, 2015d).

In 2013, the New Mexico Environment Department, Public Service Company of New Mexico and EPA agreed to meet the requirements of the federal regional haze rule through the shutdown of two units at the San Juan Generating Station by the end of 2017. The agreement also requires the installation of selective non-catalytic reduction technology on the remaining two units. This will result in significant reductions from current emissions levels of many pollutants: a 67% reduction in SO_2, 62% reduction in NO_x, 50% reduction in particulate matter, 44% reduction in CO, 51% reduction in VOC, 50% reduction in CO_2 and 50% reduction in mercury. The New Mexico Environmental Improvement Board approved a revision to the State Implementation Plan containing the agreement requirements in the fall of 2013.

In December 2013, three coal-fired generators were shut down at the Four Corners Power Plant as part of a plan to meet the requirements of the federal regional haze rule. The remaining two coal-fired generators will have selective catalytic reduction technology installed by 2018. These changes satisfy Best Available Retrofit Technology requirements from EPA. This will result in significant reductions from current emissions levels of many pollutants: a 36% reduction in NO_x, a 61% reduction in mercury, a 43% reduction in particulate matter, a 30% reduction in CO_2, and a 24% reduction in SO_2.

In Texas, NOx emissions from EGUs in ozone nonattainment areas (Beaumont-Port Arthur, Dallas-Fort Worth and Houston-Galveston-Brazoria) are required to limit NOx emissions from utility boilers, auxiliary steam boilers, stationary gas turbines and duct burners under 30 TAC Chapter 117, Subchapter C. The Texas proposed regional haze SIP did not require BART-eligible EGUs to install controls because the state of Texas determined impact of each plant's emissions did not significantly degrade visibility in a Class I area, or facilities had already reduced emissions or shut down units. On December 16, 2014, EPA proposed to partially disapprove the Texas regional haze SIP and also propose a Federal Implementation Plan to require SO_2 emissions reductions at fifteen Texas BART-eligible sources.

In Oklahoma, Tulsa Public Service Company of Oklahoma will retire one coal-fired unit at Oologah by April 2016 and install a dry sorbent injection system on a second coal-fired unit at the same time. The second unit will be shut down by December 31, 2026 to meet the requirements of the federal regional haze rule. In 2016, SO_2 emissions will be reduced by 78% and NO_2 emissions will be reduced by 81%. In 2011, EPA disapproved the Oklahoma SIP revision plan for controls at Oklahoma Gas and Electric's Sooner and Muskogee Units and the AEP/PSO Northeastern Units 3 and 4. EPA determined that dry scrubber control technology was needed at these units to meet federal haze rule requirements. The disapproval has been challenged by the State of Oklahoma, upheld by the courts and has now been appealed to the Supreme Court by the State of Oklahoma. Oklahoma submitted a SIP revision in 2013 that was approved by EPA in March 2014 that revises the BART determination for AEP/PSO Units 3 and 4. The revised determination included short-term compliance with emissions limits, shut down of one of the units by April 16, 2016, and shut down of the other unit by December 31, 2026.

In Kansas, emissions at four coal-fired units were significantly reduced as a result of the federal regional haze rule. At Kansas City Power and Electric's La Cygne plant, SCR was installed on both units and

scrubbers were installed. This resulted in 83% reduction in NO_x emissions and 82% reduction in SO_2 emissions. At Westar's Jeffrey coal-fired units, low-NOx burner installation and switching to natural gas combustion resulted in an 82% reduction in NO_x emissions and a 34% reduction in SO_2 emissions.

FOSSIL FUEL PRODUCTION

Fossil fuel production contributes to air pollutants and GHG emissions in the Farmington and Carlsbad Field Office areas, especially San Juan, Northwestern Sandoval, Eddy, Lea, and Chaves counties as well as in parts of Oklahoma, Kansas and Texas. This includes oil and gas production, natural gas compressor stations and pipelines, gas plants, and petroleum refining. Coal mining is also occurring in the FFO and Oklahoma Field Office (OFO) areas. Potash mining in the CFO area also contributes to air contaminant and GHG emissions.

The BLM has jurisdiction over federal oil and gas exploration and production on Federal and Indian mineral estate. Once produced oil or gas leaves the well location (via pipeline or tanker truck), the BLM no longer has jurisdiction over these products.

There are currently approximately 16,289 oil and gas wells on federal mineral estate in the counties within FFO (San Juan, Rio Arriba, Sandoval, and McKinley) that are categorized as active, new or temporarily abandoned (Petroleum Recovery Research Center, 2015). If oil and gas wells with private (fee), state-owned, or Indian mineral estate in these counties are included, there is a total of 23,364 active, producing, and inactive (shut in or temporarily abandoned) wells in the area. Table 6 shows 2012 oil and gas production on federal leases by state and as a percentage of U.S. production.

There are currently approximately 17,798 oil and gas wells on federal mineral estate in the counties within CFO (Eddy, Lea and Chavez) that are categorized as active, new or temporarily abandoned (Petroleum Recovery Research Center, 2015). If oil and gas wells with private (fee), state-owned, or Indian mineral estate in these counties are included, there are approximately 40,488 active, producing, and inactive (shut in or temporarily abandoned) wells in the area.

BLM's Automated Fluid Minerals Support System (AFMSS) provides information about federal mineral estate in Kansas, Oklahoma and Texas for fiscal year 2014 (U.S. Department of the Interior, 2015). There were approximately 413 oil and gas wells on federal mineral estate and 78,131 total oil and gas wells in Kansas (calendar year 2012) (Kansas Geological Survey, 2015); 469 oil and gas wells on federal mineral estate and 180,000 total oil and gas wells in Oklahoma (calendar year 2011) (Oklahoma Corporation Commission, 2011); there were 556 oil and gas wells on federal mineral estate and 319,604 total active oil and gas wells in Texas (calendar year 2012) (Railroad Commission of Texas, 2015).

Table 6: 2014 Oil and Gas Production (Petroleum Recovery Research Center, 2015), (U.S. Department of Interior Office of Natural Resources Revenue, 2015), (U.S. Energy Information Administration, 2015), (U.S. Energy Information Administration, 2015a)

Location	Oil (bbl)	% U.S. Total	Gas (MMcf)	% U.S. Total
United States	3,161,866,000	100	27,271,326	100
New Mexico	121,206,000	3.83	1,267,646	4.65
Federal leases NM	64,889,645	2.05	770,572	2.83
San Juan Basin	4,494,909	0.14	524,408	1.92
Permian Basin	60,394,736	1.91	246,164	0.90
Kansas	49,521,000	1.57	292,467*	1.07
Federal leases KS	267,542	0.01	4,807	0.02
Oklahoma	128,026,000	4.05	2,310,114	8.47
Federal leases OK	253,262	0.01	12,267	0.04
Texas (onshore)	1,154,855,000	36.52	8,627,615	31.64
Federal leases TX	411,954	0.01	35,086	0.13

*2014 data

Table 7 shows the estimated GHG emissions for oil and gas field production for the U.S., New Mexico, Kansas, Oklahoma and Texas and for Federal leases in those states including New Mexico portions of the San Juan and Permian Basins. Because oil and gas leaves the custody and jurisdiction of the BLM after the production phase and before processing or refining, only emissions from the production phases are considered here. It should also be remembered that following EPA protocols, these numbers do not

include fossil fuel combustion, which would include such things as truck traffic, pumping jack engines, compressor engines and drill rig engines. Nor does it include emissions from power plants that generate the electricity used at well sites and facilities. Note that units of metric tons CO_2e have been used in Table 6 to avoid very small numbers.

Table 7 provides an estimate of direct emissions that occur during exploration and production of oil and gas. For natural gas, extraction accounts for 55% of total life cycle CO_2e emissions, processing accounts for 27% and transmission accounts for 18% of life cycle CO_2e emissions (U.S. Department of Energy, 2011). For oil, drilling and development is responsible for 8% of the total life cycle CO_2e emissions, whereas transportation of the petroleum to refineries represents about 10% of the emissions, and final consumption as transportation fuel represents fully 80% of emissions (U.S. Department of Energy, 2008).

Table 7: 2014 Oil and Gas Field Production Emissions (metric tons CO_2e) (U.S. Environmental Protection Agency, 2016j)

Location	**Oil** (Metric Tons CO_2e)		**Gas** (Metric Tons CO_2e)		**Total O&G Production** (Metric Tons CO_2e)	**%U.S. Total GHG Emissions**
	CO_2	**CH_4**	**CO_2**	**CH_4**		
United States	600,000	67,400,000	18,600,000	109000000	195,600,000	2.847
New Mexico	23,000	2,583,691	864,579	5,066,619	8,537,889	0.124
Federal Leases NM	12,314	1,383,222	525,557	3,079,878	5,000,970	0.073
San Juan Basin	853	95,816	357,665	2,095,992	2,550,325	0.037
Permian Basin	11,461	1,287,406	167,892	983,886	2,450,645	0.036
Kansas	9,397	1,055,616	199,473	1,168,953	2,433,439	0.035
Federal Leases KS	51	5,703	3,279	19,213	28,245	0.000
Oklahoma	24,294	2,729,070	1,575,579	9,233,230	13,562,173	0.197

Federal Leases OK	48	5,399	8,367	49,030	62,843	0.001
Texas	219,147	24,617,497	5,884,336	34,483,473	65,204,453	0.949
Federal Leases TX	78	8,781	23,930	140,234	173,024	0.003

The New Mexico Greenhouse Gas Inventory and Reference Case Projection 1990-2020 (New Mexico Environment Department, 2006) estimates that approximately 17.3 million metric tons of GHGs from the natural gas industry and 2.3 million metric tons of GHGs from the oil industry were projected in 2010 as a result of oil and natural gas production, processing, transmission and distribution. As of June 9, 2015, there were 20,339 active oil wells and 26,387 active gas wells in New Mexico (Petroleum Recovery Research Center, 2015).

Compressor engines link the natural gas pipeline infrastructure that transports natural gas from its source to points of consumption. Table 8 shows the greenhouse gas emissions from compressor stations and gas plants for each state from the 2013 Greenhouse Gas Facility Level Information on Greenhouse Gases Tool (FLIGHT). Some gas plants and compressor stations' emissions may not be reported to FLIGHT because emissions from the plant or station do not exceed EPA's GHG reporting threshold.

Table 8: 2014 Greenhouse gas emissions from gas plants and compressor stations (U.S. Environmental Protection Agency, 2016h)

State	Number of reporting compressor stations	Total GHG emissions from reporting compressor stations (MMT CO_2e)	**%U.S. Total reported Compressor Station GHG Emissions**	Number of reporting gas plants	Total GHG emissions from reporting gas plants (MMT CO_2e)	**%U.S. Total reported Gas Plant GHG Emissions**
New Mexico	6	0.33	1.5	26	5.3	8.83
Texas	49	2.3	10.4	207	21.0	35.0
Oklahoma	15	0.50	2.27	49	2.8	4.67

Kansas	24	1.1	5.0	5	0.60	1.0

Emissions from processing, transmission and storage and distribution in the U.S. totaled 98 million metric tons of CO_2e in 2013, which was about 3% of total U.S. GHG emissions reported to EPA in 2013 (U.S. Environmental Protection Agency, 2016h).

In 2015, EPA Natural Gas Star partner companies operate 51% of the active federal wells in the New Mexico portion of the San Juan Basin and 13% of the active federal wells in the New Mexico portion of the Permian Basin. In Kansas, Natural Gas Star partner companies operate 5% of the active federal wells; in Oklahoma, Natural Gas Star partner companies operate 11% of the active federal wells and in Texas, Natural Gas Star partner companies operate 33% of the active federal wells (Petroleum Recovery Research Center, 2015) (U.S. Department of Interior Bureau of Land Management, 2014). EPA has found Natural Gas Star partners' actions to result in measurable decreases in GHG emissions since the program's implementation.

Crude oil produced throughout the BLM-NM area is transported by pipeline and/or tanker truck to refineries where the oil is processed into various types of fuel. Table 9 shows the greenhouse gas emissions from refineries in each BLM-NM state.

Table 9: 2014 Greenhouse gas emissions from refineries (U.S. Environmental Protection Agency, 2016h)

State	Number of Reporting Refineries	Total GHG emissions from reporting compressor stations (MMT CO_2e)	**%U.S. Total reported Refinery GHG Emissions**
New Mexico	3	0.95	0.54
Texas	29	55	31.4
Oklahoma	5	4.7	2.7
Kansas	3	2.8	1.6

There are two refineries in the CFO area, one in Artesia and one in Lovington. There is one refinery near Gallup, NM operating in the FFO area. In Kansas, there are three refineries, Oklahoma has five refineries and Texas has twenty-eight refineries. Transportation and processing of crude oil and petroleum products result in emissions of various hazardous air pollutants, criteria pollutants, and GHGs. In 2013, greenhouse gas emissions from refineries accounted for 177 million metric tons CO_2e emitted (U.S. Environmental Protection Agency, 2016h), which is 5.6% of the total GHG emissions reported to EPA.

Potash mining is another major industry in the CFO area. There are two mining companies operating 4 potash processing plants in the CFO area. Potash production produces emissions of various hazardous air pollutants and criteria pollutants. In 2013, potash mines in southeastern New Mexico emitted 97,726 metric tons of CO_2e cumulatively. This is 0.001% of total greenhouse gas emissions (U.S. Environmental Protection Agency, 2016h).

Coal mining is another major industry in San Juan County. BHP Billiton operates two coal mines in northwestern New Mexico that provide coal to the San Juan Generating Station and the Four Corners Power Plant. Coal production produces emissions of various hazardous air pollutants, criteria pollutants, and CH_4. In 2013, coal mining in the U.S. contributed 63.2 million metric tons CO_2e, which is 10.8% of total U.S. CH_4 emissions, and 1.1% of total U.S. GHG emissions (U.S. Environmental Protection Agency, 2016j).

TRANSPORTATION

Another primary source of emissions that impact air quality is vehicular travel. The number of vehicles, miles traveled, types of vehicles in use, and the condition of road surfacing, all factor into the emissions from vehicular travel. On and off-road vehicles produce exhaust which contains NOx, VOCs, CO, PM and HAPs.

In 2013, fossil fuel combustion associated with transportation contributed 1,801.7 million metric tons CO_2e to total U.S. GHG emissions, which accounted for 27% of U.S. GHG emissions that year (U.S. Environmental Protection Agency, 2016j). Over 90% of the fuel used for transportation is petroleum based. Although it is expected that vehicle fuel efficiency and increased use of public transportation will reduce vehicle emissions, these reductions may eventually be offset by an increased number of vehicles in use due to population growth in the region.

CLIMATE CHANGE AND GHG EMISSIONS

Secretarial Order 3289, issued on September 14, 2009, established a Department-wide approach for applying scientific tools to increase understanding of climate change and to coordinate an effective response to its impacts on tribes, and on the land, water, ocean, fish and wildlife, and cultural heritage resources the Department manages. The Secretarial Order states that one must “consider and analyze

potential climate change impacts when undertaking long-range planning exercises, setting priorities for scientific research and investigations, and/or when making major decisions affecting DOI resources." BLM does recognize the importance of climate change and the potential effects it could have on natural and socioeconomic environments. Since the assessment of GHG emissions and climate change is in its formative phase it is currently not feasible to predict the exact impacts the Proposed Action would have on climate and projected

For the purpose of NEPA analysis, EPA emission factors can be used to include a qualitative and quantitative analysis of possible greenhouse gas emissions that could occur as a result of reasonably foreseeable coal, oil, gas or other development connected to federal land and resource management use. Estimates are made based on readily available data and reasonable assumptions about potential future development. More detailed emissions would be available and calculated at a site specific level of analysis such as those that occur at an APD stage.

Existing conditions of air resources in any given location are the result of numerous complex factors, both natural and human caused. Natural factors contributing to the current condition of air resources include existing climate resulting from long-term atmospheric weather patterns, soil types, and vegetation types. Anthropogenic factors contributing to the current condition of air resources include long-term human habitation, growing human populations, transportation methods and patterns, recreational activities, economic patterns, the presence of power plants and other industrial sources. The presence of natural resource (i.e. oil and natural gas) extraction and processing on some BLM lands also impact air quality and greenhouse gas emissions.

The primary sources of greenhouse gas emissions could include the following:

- Fossil fuel combustion for construction and operation of oil and gas facilities – vehicles driving to and from production sites, engines that drive drill rigs, etc. These produce CO_2 in quantities that vary depending on the age, types, and conditions of the equipment as well as the targeted formation, locations of wells with respect to processing facilities and pipelines, and other site-specific factors.
- Fugitive CH_4 – CH_4 that escapes from wells (both gas and oil), oil storage, and various types of processing equipment. This is a major source of global CH_4 emissions. These emissions have been estimated for various aspects of the energy sector, and starting in 2011, producers are required under 40 C.F.R. §98, to estimate and report their CH_4 emissions to the EPA.
- Combustion of produced oil and gas – it is expected that operations will produce marketable quantities of oil and/or gas. Combustion of the oil and/or gas would release CO_2 into the atmosphere. Fossil fuel combustion is the largest source of global CO_2.

Direct GHG Emissions

Direct greenhouse gas emissions from speculative future oil and gas well production and associated activities of the proposed action are summarized in the respective NEPA document. Total Greenhouse Gas Warming Potential (GWP), which includes direct emissions of carbon dioxide, methane, and nitrous oxide from an oil or gas producing well is calculated.

Indirect GHG Emissions

Indirect GHG emissions are estimated based on speculative annual oil, gas, and/or natural gas liquids from the proposed action. Indirect GHG emissions are calculated only for carbon dioxide based on combustion of the product. Emission factors are applied to the per-barrel or per-cubic foot unit of the reasonably foreseeable development estimates. Emission factors used in BLM GHG Indirect Greenhouse Gas Emissions are included below.

Oil indirect emission factor: 0.43 MT CO2 per Barrel (EIA, 2006),

Gas indirect emission factor: 0.054717 MT of CO2 per Mcf (U.S. Environmental Protection Agency, 2016k)

Natural Gas Liquids indirect emission factor 13.7 pounds of CO2 per gallon of Prop/Buta mix (EIA, 2006)

End Uses

Estimating direct and indirect GHG emissions attempt to provide a complete GHG lifecycle of a well from site inspection to possible emissions through combustion. A rough estimate was possible using publicly available information and using estimates from future production for reasonably foreseeable development. With respect to the rough estimates of indirect CO_2 emissions, it should be noted that it is a difficult to discern with certainty what end uses for the fuels extracted from a particular leasehold might be reasonably foreseeable. For instance, some end uses of fossil fuels extracted from Federal leases include: combustion of transportation fuels, fuel oils for heating and electricity generation, as well as production of asphalt and road oil, and the feedstocks used to make chemicals, plastics, and synthetic materials. At this time, there is some uncertainty with regard to the actual development that may occur.

It is important to note that the BLM does not exercise control over the specific end use of the oil and gas produced from any individual federal lease. The BLM has no authority to direct or regulate the end use of the produced oil and/or gas. As a result, the BLM can only provide an estimate of potential GHG emissions using national approximations of where or how the end use may occur because coal, oil, condensate, and natural gas could be used for combustion of transportation fuels, fuel oils for heating and electricity generation, as well as production of asphalt and road oil, and the feedstocks used to make chemicals, plastics, and synthetic materials.

Global, National And State GHG Emissions

It is useful to compare the relative and absolute contributions to climate change of different GHG emissions, as well as emissions from different regions/countries or sources/sectors. There are several different metrics that can be used for this comparison. The most common is Global Warming Potential (GWP), a relative measure that compares the heat absorbing ability of a certain mass of a gas relative to the same mass of carbon dioxide (CO_2). A second metric that is gaining prominence is Global Temperature change Potential (GTP). GTP is based on the change in global mean surface temperature at a chosen point in time, relative to that caused by CO_2. A number of other metrics may also be used, but no single metric accurately compares all consequences and the choice of metric is a value judgment (Intergovernmental Panel on Climate Change (IPCC), 2013).

Global Warming Potential (GWP) is dependent both upon the heat-absorbing ability of a particular gas and its atmospheric lifetime. A gas that is quickly removed from the atmosphere may have a high GWP over a short period of time, but a lower impact over a longer time period. For example, methane gas (CH_4) has a GWP of 56 over a 20-year time horizon and a GWP of 21 over a 100-year time horizon (Intergovernmental Panel on Climate Change (IPCC), 1996). This means that CH_4 is 56- and 21-times more potent than CO_2 over these time periods. The most potent GHG ever evaluated is sulfur hexafluoride (SF_6). Although trace gases such as SF_6 are present in low concentrations, they have high GWPs because they are both very effective at trapping heat and have very long atmospheric lifetimes.

In accordance with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC) and in order to maintain consistent comparisons over the years, official GHG emission estimates for the United States are reported based on the GWP values given in the IPCC Second Assessment Report (SAR) (Intergovernmental Panel on Climate Change (IPCC), 1996). These values have been revised in the IPCC Third (Intergovernmental Panel on Climate Change (IPCC), 2001), Fourth (Intergovernmental Panel on Climate Change (IPCC), 2007), and Fifth (Intergovernmental Panel on Climate Change (IPCC), 2013) Assessment Reports as our level of scientific understanding increases. The atmospheric lifetimes and GWPs for the major GHGs over a 100-year time horizon from the Second Assessment Report (SAR) are listed below in Table 10.

Table 10. Global Warming Potential (100-year time horizon) (Intergovernmental Panel on Climate Change (IPCC), 1996)

Greenhouse Gas	Lifetime (years)[1]	GWP[1]
Carbon dioxide, CO_2	Varies	1
Methane, CH_4	12	21
Nitrous oxide, N_2O	120	310
Select Hydrofluorocarbons, HFCs	1.5 – 264	140 – 11,700
Sulfur hexafluoride, SF_6	3,200	23,900

A GHG emission inventory is used to identify and quantify the anthropogenic GHG emissions from different regions/countries or sources/sectors. Using the GWP concept, GHG emissions are often reported in terms of carbon dioxide equivalent (CO_2e). The World Resources Institute's (WRI's) Climate Analysis Indicators Tool (World Resources Institute, 2017) provides data on GHG emissions from 186 countries and all 50 states. In 1990 total global GHG emissions were 33,823 million metric tons of CO_2 equivalent (Mt CO_2 Eq.); In 2013, total global GHG emissions were 48,257 million metric tons of CO_2 equivalent (Mt CO_2 Eq.), including land-use change and forestry. From 1990 to 2013, global GHG emissions have increased at an annual rate of 3.3%. Electricity generation, manufacturing/construction, and transportation account for roughly 31%, 13%, and 15% of total global GHG emissions, respectively (World Resources Institute, 2017).

To meet the obligations of the UNFCCC, the U.S. Environmental Protection Agency (EPA) publishes the national GHG emissions inventory on an annual basis (U.S. Environmental Protection Agency, 2016d). In 2014, total U.S. GHG emissions were 6,870.5 Mt CO_2e. Total U.S. emissions have increased by 7.4 percent from 1990 to 2014. Emissions increased from 2013 to 2014 by 1 percent due to an increase in fossil fuel combustion. Fossil fuel combustion increases were a result of: (1) Cold winter conditions in the first quarter of 2014, resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled and fuel use across on-road transportation modes and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions. From 1990 to 2014, U.S. emissions have increased at an annual rate of 0.3%. Figure 6 illustrates U.S. GHG emissions by gas from 1990 through 2014. Figure 7 shows U.S. greenhouse gas emissions and sinks by economic sector from 1990 to 2014. Electricity generation and transportation are the largest sources of GHGs in the U.S., accounting for 30% and 25.6% of emissions since 1990, respectively.

Figure 6. U.S. greenhouse gas (GHG) emissions by gas from 1990 to 2014 (U.S. Environmental Protection Agency, 2016j).

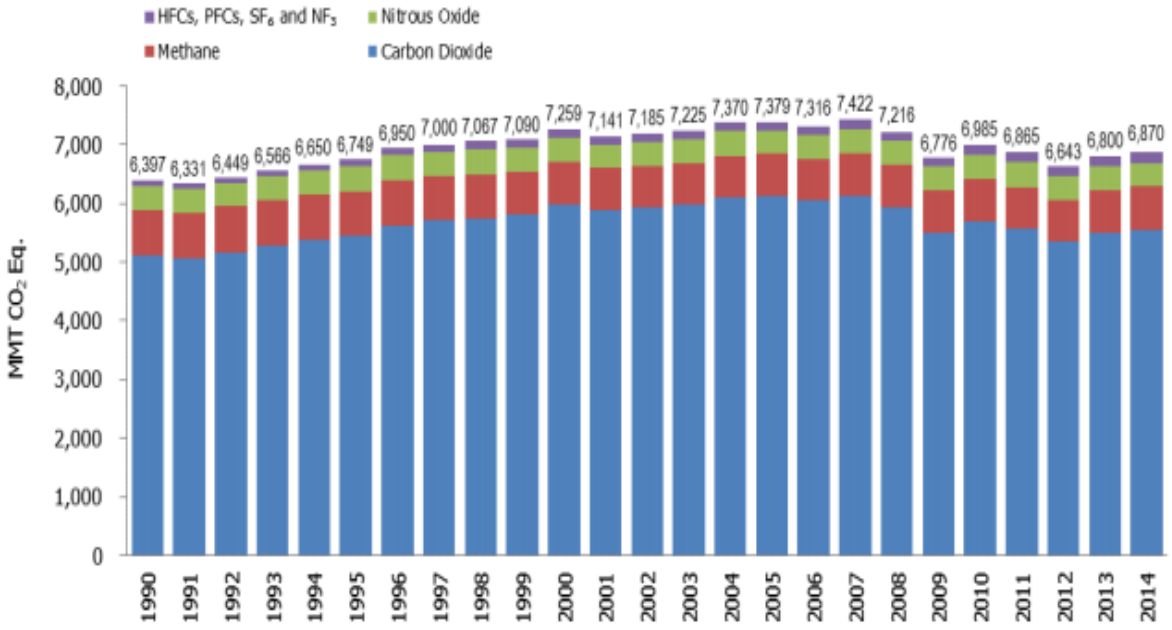
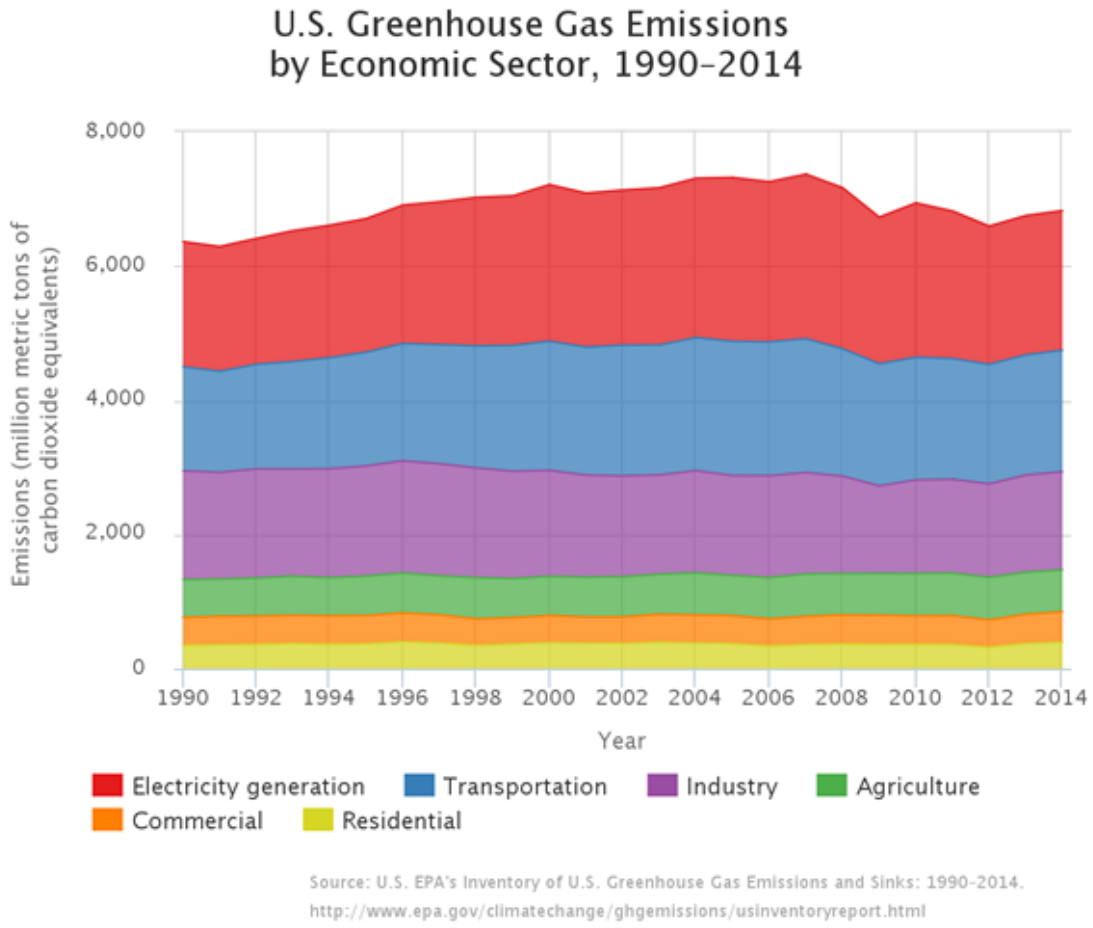


Figure 7. U.S. greenhouse gas (GHG) emissions and sinks by economic sector from 1990 to 2014 (U.S. Environmental Protection Agency, 2016j).



Globally, emissions of CO_2 from flaring of unused gas during oil production decreased by about a quarter between 2003 and 2011; however, flaring emissions for the U.S. are on the rise and increased by 50% in 2011 because of the significant increase in fracking for shale oil production and the flaring of co-produced natural gas (Olivier, 2012).

The Inventory of New Mexico Greenhouse Gas Emissions: 2000-2013 (New Mexico Environment Department, 2016) lists total statewide gross GHG emissions in 2013 as 80.9 Mt CO_2 Eq. For 2013, New Mexico's Environment Department reported that the primary contributors to the state's GHG emissions were electricity generation (35%), the fossil fuel industry (26%), and transportation (17%) (New Mexico Environment Department, 2016). In 2012, WRI's CAIT reports that New Mexico's GHG emissions were 75.5 Mt CO_2 Eq. (World Resources Institute, 2017). Electricity generation, transportation, and fugitive sources account for around 29%, 14%, and 11% of New Mexico's GHG emissions in 2012 (World

Resources Institute, 2017). According to the New Mexico Greenhouse Gas Inventory and Reference Case Projections, 1990-2020, GHG emissions were expected to continue increasing (New Mexico Environment Department, 2006). From 1990 to 2012, New Mexico's GHG emissions have decreased at an annual rate of 0.45% (New Mexico Environment Department, 2016).

With respect to GHGs emitted by oil and gas development, carbon dioxide (CO_2) is produced during the burning of fossil fuels to run internal combustion engines which may be used in drilling, transportation, pumping and compression. Carbon dioxide may be a significant component of natural gas, especially coalbed methane, and is vented during field operations or processing. Carbon dioxide is also used in enhanced oil production processes and may be released or escape to the atmosphere during those processes. Methane (CH_4) is the primary component of natural gas and is released to the atmosphere during both oil and gas production either intentionally during production when it cannot be captured, or accidentally through leaks and fugitive emissions.

The EPA's national GHG emissions inventory describes "Natural Gas Systems" and "Petroleum Systems" as two of the major sources of U.S. GHG emissions. The inventory identifies the contributions of natural gas and petroleum systems to total carbon dioxide (CO_2) and methane (CH_4) emissions (natural gas and petroleum systems do not produce noteworthy amounts of any other GHGs). Within the larger category of "Natural Gas Systems", the EPA identifies emissions occurring during distinct stages of operation, including field production, processing, transmission and storage, and distribution.

Table 11. U.S. Inventory of Greenhouse Gas Emissions for oil and gas subsectors 2014 (U.S. Environmental Protection Agency, 2016j)

Sector	**Subsector**	**2014 GHG Emissions ($MMTCO_2e$)**				**% of U.S. Total GHGs**
		CO2	CH4	N_20	Total GHGs	
Natural Gas Systems	Total	42.4	176.1	*	218.2	3.18%
	Field production	18.6	109.0	*	127.6	1.86%
	Processing	23.7	24.0	*	47.7	0.69%
	Transmission and storage	*	32.1	*	32.1	0.47%

	Distribution	*	11.1	*	33.3	0.48%
Petroleum Systems	Total	3.6	68.1	*	71.7	1.04%
	Production field operations	0.6	67.4	*	68.0	0.99%
	Crude oil transportation	**	0.2	*	0.2	0.003%
	Crude refining	2.9	0.6	*	6.3	0.09%
Fossil Fuel Combustion	Total	5167.2	10.0	39.6	5450.1	79.3%
	Electricity generation	2,039.3	0.4	19.6	2059.3	30.0%
	Transportation	1,737.6	2.0	16.3	1755.9	25.6%
	Industrial	813.3	1.5	2.4	817.2	11.9%
	Residential	345.1	5.0	1.0	351.1	5.1%
	Commercial	231.9	1.1	0.3	233.3	3.4%
Coal Mining	--	*	67.6	*	67.6	0.98%

U.S. Total		5,556.0	730.8	403.5	6870.5 ***	100%

*Indicates values less than 0.1 TgCO2e

**Indicates values that do not exceed 0.05 TgCO2e

***Indicates that the total U.S. GHG emissions value includes U.S. emissions of three additional minor classes of GHGs.

In Table 11, CO_2 emissions listed for sectors other than "Fossil Fuel Combustion" represent non-combustion CO_2 emissions. The natural gas and petroleum subsectors that BLM regulates for on-shore operations on federal mineral estate are highlighted in gray.

"Petroleum Systems" sub-activities include production field operations, crude oil transportation and crude oil refining. Within the Natural Gas Systems and Petroleum Systems the BLM has authority to regulate those field production operations that are related to oil and gas measurement and prevention of waste (via leaks, spills and unauthorized flaring and venting).

The EPA reports that from 1990 to 2014, national emissions from Natural Gas Systems decreased by 15% for methane ($C4_4$) due to decreases in emissions from transmission, storage, and distribution. The decrease in transmission and storage emission is largely due to reduced compressor station emissions (including emissions from compressors and fugitives). The decrease in distribution emissions in largely attributed to increased use of plastic piping, which has lower emissions than other pipe materials, and station upgrades at metering and regulating (M&R) stations. For Petroleum Systems, methane emissions increased by 76% from 1990 to 2014, mainly due to increases in emissions from production equipment (U.S. Environmental Protection Agency, 2016j).

POTENTIAL MITIGATION STRATEGIES

The reduction of emissions of air pollutants and greenhouse gases from oil and gas operations has been the subject of much study and discussion in recent years. The EPA Natural Gas Star Program established in 1993 has been a leader in developing and reporting on strategies to reduce methane emissions (U.S. Environmental Protection Agency, 2015e). These reductions can help to control not only greenhouse

gases but also VOCs, which contribute to ozone formation. Numerous opportunities for emissions reduction, including costs to implement, are documented on EPA's the Natural Gas Star website.

A report by the Government Accountability Office (GAO) noted that opportunities exist for capturing fugitive emissions from venting and flaring of natural gas on wells under federal jurisdiction (U.S. Government Accountability Office, 2010). A report prepared for BLM in Montana includes an entire chapter on reduction of emissions of greenhouse gases (URS Corporation, 2010a). Another report recently issued by the U.S. Forest Service summarizes and builds on work originally done by BLM to identify Best Management Practices for protection of air quality during oil and gas development and production (U.S. Forest Service, 2011).

While it is beyond the scope of this report to detail the wide range of mitigation strategies available it must be understood that for the most part these strategies must be applied on a case by case basis at the project level. Some broader range strategies applied within the BLM New Mexico State Office jurisdiction are discussed below.

FOUR CORNERS AIR QUALITY TASK FORCE

In 2002, the State of New Mexico Environment Department and local governments convened to sign an Early Action Compact (EAC) for ozone under a US EPA program that required commitment for state and local action to resolving ozone issues prior to a nonattainment designation. In 2005, the states of Colorado and New Mexico convened a group of stakeholders, then known as the Four Corners Air Quality Task Force (Task Force), to address air quality issues in the Four Corners region in light of continued energy development and growth in the region and consider options for mitigating air pollution. A report detailing a wide range of mitigation options was published in November 2007 (Four Corners Air Quality Task Force, 2007).

In 2008, its task complete, the group became known as the Four Corners Air Quality Group (FCAQG) and continued on as a forum for discussion of existing air quality issues and potential solutions. The FCAQG is currently comprised of more than 100 members and 150 interested parties representing a wide range of perspectives on air quality in the Four Corners region. Members include private citizens, representatives from public interest groups, universities, industry, state, tribal and local governments, and federal agencies. The BLM has been an active participant from the beginning and maintains a representative on the steering committee.

IR CAMERAS

The BLM has two Infrared Cameras which are being used to detect leaks and fugitive emissions. BLM inspectors carry these cameras into the field and have been able to alert operators of equipment

requiring repair or maintenance. At this time the cameras are being used in an advisory rather than a regulatory role.

FOUR CORNERS METHANE HOTSPOT

Very recently, pioneering research using space-borne (satellite and aircraft) determination of methane concentrations has indicated anomalously large methane concentrations may occur in the Four Corners region (Kort, et al., 2014). A subsequent study (Schneising, et al., 2014) indicated larger anomalies over other oil and gas basins in the U.S. Methane is 34 times more potent at trapping greenhouse gas emissions than CO_2 when considering a time horizon of 100 years (Intergovernmental Panel on Climate Change, 2013). While space-borne studies can determine the pollutant concentration in a column of air, these studies cannot pinpoint the specific sources of air pollution. Further study is required to determine the sources responsible for methane concentrations in the Four Corners region; however, it is known that a significant amount of methane is emitted during oil and gas well completion (Howarth, Santoro, & A.Ingraffea, 2011). Methane is also emitted from process equipment, such as pneumatic controllers and liquid unloadings, at oil and gas production sites. Ground-based, direct source monitoring of pneumatic controllers conducted by the Center for Energy and Environmental Resources (Allen, et al., 2014) show that methane emissions from controllers exhibit a wide range of emissions and a small subset of pneumatic controllers emitted more methane than most. Emissions measured in the study varied significantly by region of the U.S., the application of the controller and whether the controller was continuous or intermittently venting. The Center for Energy and Environmental Resources had similar findings of variability of methane emissions from liquid unloading (Allen, et al., 2014a). In October 2012, USEPA promulgated air quality regulations controlling VOC emissions at hydraulically fractured gas wells. These rules require air pollution mitigation measures that reduce the emissions of volatile organic compounds. These same mitigation measures have a co-benefit of reducing methane emissions. In April 2015, several researchers conducted further ground-based and space-borne studies utilizing emerging pollutant measurement technology. The results of these studies may help to pinpoint significant, specific sources of methane emissions in the region.

KANSAS, OKLAHOMA AND TEXAS

The BLM has jurisdiction over mineral rights on federal lands managed by other agencies and on split estate lands in Kansas, Texas and Oklahoma. A review of Table 6 above will show that oil and gas production on federal leases is fairly small compared to production on other lands in these states. The purpose of this chapter is to address air quality concerns and regulations that are unique to these states and not already covered above.

KANSAS

The regulatory authority for air quality in Kansas is the Kansas Department of Health and Environment, Bureau of Air (http://www.kdheks.gov/bar/). The state does not have any ambient air quality standards that differ from the NAAQS (Table 1). There are currently no non-attainment areas for any criteria pollutant in the state of Kansas.

OKLAHOMA

The regulatory authority for air quality in Oklahoma is the Oklahoma Department of Environmental Quality, Air Quality Division (http://www.deq.state.ok.us/AQDnew/). Oklahoma's ambient air quality standards are identical with the NAAQS (Table 1). There are currently no nonattainment areas in the state of Oklahoma.

TEXAS

The regulatory authority for air quality in Texas is the Texas Commission on Environmental Quality (TCEQ), Air Division. The state does not have any ambient air quality standards that differ from the NAAQS (Table 1).

Non-Attainment Areas And Conformity Analysis

There are currently four non-attainment areas in Texas, one for PM_{10} (El Paso), two for ozone (Houston area, Dallas-Fort Worth area) and a portion of Collin County is non-attainment for lead, according to the TCEQ website (http://www.tceq.texas.gov). EPA's conformity rule requires that all federal actions in a non-attainment area must demonstrate conformity with the State Implementation Plan (SIP) for the pollutant in question. If the agency can demonstrate that emissions for the action will fall below certain established levels, known as de minimus, then no further analysis is necessary. In order to establish de minimus an emissions inventory for the project is required. In the case of ozone, the emissions inventory would include NOx and VOCs. If emissions are projected to be above de minimus levels further analysis should be coordinated with the EPA and Texas CEQ.

The Houston-Galveston-Brazoria area was designated as severe nonattainment for 8 hour ozone based on the 1997 standard in October 2008 and includes the following counties: Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller. De minimus values for both NOx and VOC in this area are 25 tons/year.

The Dallas-Fort Worth ozone nonattainment area was designated in June 2004, is classified as moderate and includes the following counties: Collin, Dallas, Denton, Tarrant, Ellis, Johnson, Kaufman, Parker, and Rockwall. De minimus values in this area are 100 tons/yr for NOx and 50 tons/yr for VOC.

AIR QUALITY MODELING FOR TEXAS

Numerous reports on air quality modeling projects done by and for the TCEQ, including modeling done for the Dallas and Houston non-attainment areas can be accessed on the Air Division website (http://www.tceq.texas.gov/airquality/airmod/am). The TCEQ has convened advisory groups in southeastern Texas and Dallas-Fort Worth to assist the agency in addressing photochemical modeling issues.

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