Protecting Human Health and the Environment through Rigorous, Cost-Effective Emission Standards for the Oil and Gas Industry

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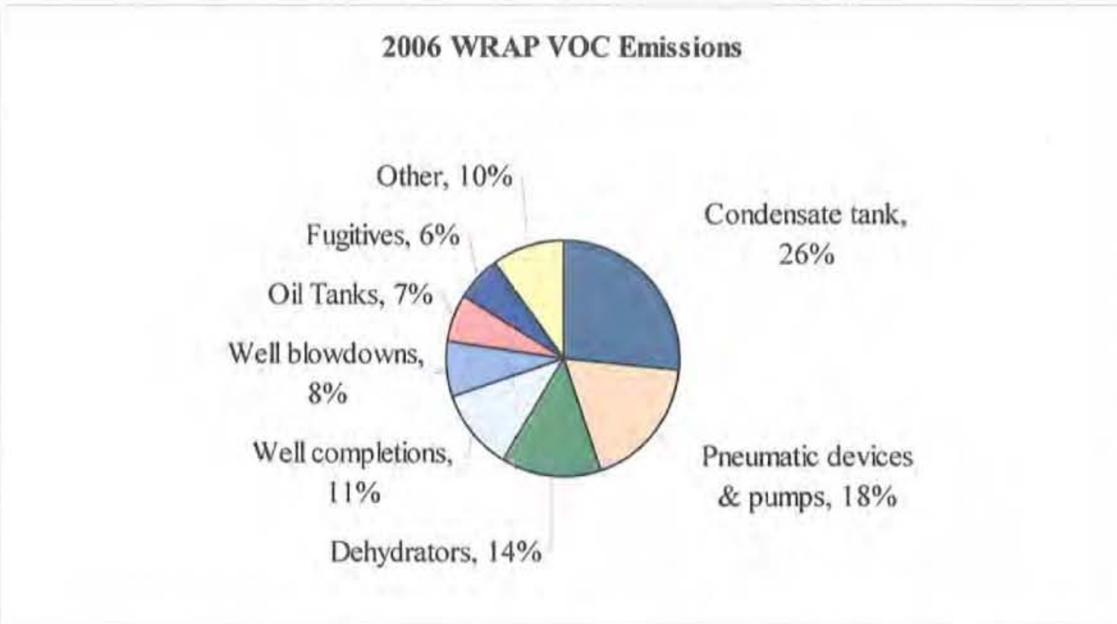
I. INTRODUCTION

The production and development of crude oil and natural gas contributes significantly to air pollution that endangers human health and the environment. Activities in the natural gas exploration and production, storage, processing, transmission and distribution sectors and in the oil exploration and production sectors (cumulatively "oil and gas activities") emit substantial amounts of volatile organic compounds ("VOCs"), oxides of nitrogen ("NOx"), methane ("CH_4") and hazardous air pollutants ("HAPs"). These airborne contaminants contribute to pollution associated with serious human health effects and adverse environmental consequences including ground-level ozone or "smog", particulate pollution, toxic air pollution, climate-disrupting pollution, and the haze that obscures scenic vistas in national parks and wilderness areas.

Emissions from the burgeoning Pinedale-Anticline natural gas field in Wyoming are the source of winter-time ozone exceedances which led the Governor of Wyoming to request that EPA designate Sublette County and parts of Sweetwater and Lincoln counties as "nonattainment" under the 2008 8-hour ozone national ambient air quality standard.[1] Appendix A details estimated and projected VOC and NOx emissions from some of the most significant sources in key oil and gas basins in the Intermountain West and Gulf region. The following chart graphically shows the most significant sources of VOC emissions in six major Intermountain West basins including the D.J., Piceance, South San Juan, North San Juan, Uinta and Wind River.

[1] Letter to Ms. Carol Rushin, Acting Regional Administrator from Governor Dave Freudenthal (March 12, 2009).

Figure 1: **Percent Contribution of Estimated Volatile Organic Compounds from Oil and Gas Exploration and Production Sources in the D.J., Piceance, North and South San Juan, Uinta and Wind River basins (2006).**



Sources of VOCs and NOx also produce significant amounts of methane which contributes to ground-level ozone pollution as well as climate change.[2] Emissions from oil and gas activities account for the third largest source of U.S. methane emissions, contributing at least 125.5 million metric tons of CO_2 equivalent ("MMT CO_2e") in 2008 according to the most recent greenhouse gas inventory prepared by the U.S. Environmental Protection Agency.[3] The methane emissions are comparable to the greenhouse gas emissions emitted from roughly 33

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[2] Arlene M. Fiore *et al.*, *Characterizing the Tropospheric Ozone Response to Methane Emission Controls and the Benefits to Climate and Air Quality*, Journal of Geophysical Research Vol. 113, at 1 (April 30 2008) (stating that "[I]n the presence of nitrogen oxides (NOx), tropospheric CH4 oxidation leads to the formation of O3); Aaron S. Katzenstein *et al.*, *Extensive Regional Atmospheric Hydrocarbon Pollution in the Southwestern United States*, 21 PNAS Vol. 100, 11975 ("The release of hydrocarbons into the atmosphere contributed to the photochemical ozone (O3) production, with related adverse health effects, reduction in plant growth, and climate change... Ch4 is by far the most abundant hydrocarbon in the atmosphere.")

[3] EPA 2010 Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (March 2010), Table ES-2, http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

coal-fired power plants.[4] The actual emissions however, are likely much larger as emissions underreporting is well documented by EPA. Specifically, during the development of EPA's mandatory reporting of greenhouse gas rules for petroleum and natural gas systems, the Agency identified concerns with emissions accuracy for the following sources: (1) well venting for liquids unloading; (2) gas well venting during well completions; (3) gas well venting during well workovers; (4) crude oil and condensate storage tanks; (5) centrifugal compressor wet seal degassing venting; and (6) flaring. According to EPA, the emissions estimates for these sources "do not correctly reflect the operational practices of today" and, in fact, EPA believes "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory."[5]

Various sources including wells, compressor engines, glycol dehydrators and condensate tanks located at oil and gas exploration and production sites emit HAPs including benzene, a known carcinogen. For example, a recent inventory of HAP, VOC, NOx and greenhouse gas emissions in the Barnett Shale in Texas estimated the following HAP emissions in tons per day in 2009[6]:

[4] Calculated using EPA's GHG Equivalencies Calculator, http://www.epa.gov/RDEE/energy-resources/calculator.html#results.
[5] EPA Technical Support Document for the proposed GHG Mandatory Reporting Rule, p. 23; *See also* EPA Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems; Proposed Rule, 75 Fed. Reg. 18608, 18621 (April 12, 2010).
[6] Al Armendariz, Ph.D., *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*, 24 (Jan. 26, 2009).

Table 1: Barnett Shale 2009 HAP Emissions

Source	Tons per Day HAPs
Compressor engine exhaust	3.6
Condensate and oil tanks	.60
Production fugitives	.62
Well drilling and completions	.49
Gas processing	.37
Transmission fugitives*	.67

*Transmission fugitives include emissions produced by the movement of natural gas from wells to processing plants and from processing plants to compressor stations.

EPA has established a limited number of emission standards under sections 111 and 112 of the Clean Air Act that reduce a portion of the air pollution arising from oil and gas activities; these include emission standards that have not been updated in years to reflect modern pollution control technologies.[7] Further, a large number of sources and resulting air pollutants within the oil and gas industry remain uncontrolled at the federal level. A handful of western states, however, have implemented clean air policies to reduce air pollution from some of the most significant emission sources in the oil and gas industry. A comparison of the current federal and state regulatory framework as it applies to oil and gas activities is attached as Appendix B.

Wide-scale implementation of the policies currently in place at the state level has the

[7] "Equipment Leaks of VOCs From Onshore Natural Gas Processing Plants", 50 Fed. Reg. 26122 (June 24, 1985), "Onshore Natural Gas Processing SO2 Emissions", 50 Fed. Reg. 40158; "Stationary Spark Ignition Internal Combustion Engines", 73 Fed. Reg. 3568 (Jan. 18, 2008); "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage", 64 Fed. Reg. 32610 (June 17, 1999); "National Emission Standards for Hazardous Air Pollutants for Oil and Natural Gas Production Facilities", 72 Fed. Reg. 26 (Jan. 3, 2007); "National Emission Standards for Hazardous Air Pollutants for Oil and Natural Gas Production Facilities, Stationary Reciprocating Internal Combustion Engines", 73 Fed. Reg. 3568 (Jan. 18, 2008); "National Emission Standards for Hazardous Air Pollutants for Oil and Natural Gas Production Facilities for Reciprocating Internal Combustion Engines", 75 Fed. Reg. 9648 (March 3, 2010).

potential to produce meaningful air and public health benefits. Indeed, even greater clean air benefits can be achieved through the implementation of additional technologies and practices developed as part of EPA's Natural Gas STAR program. In many instances, clean air measures involve best management practices and technologies that result in minimizing the volumes of natural gas lost, leaked or vented during the development and production process, resulting in health and environmental protections as well as cost savings from improved production efficiency. EPA estimates that as much as 300 billion cubic feet of natural gas (methane) is lost to the atmosphere in the United States each year. This equals over $1 billion in lost profits, assuming the relatively low average gas prices in April 2009.[8] Broad adoption of cost-effective methane reduction technologies has the potential to reduce current estimated methane emissions from oil and gas activities by approximately 41 MMT CO_2e.[9] While companies must make an initial upfront investment to install methane capture or reduction technologies, the return on investment in many cases is quite short—sometimes months—and almost always within a single year. In 2008 companies that employed methane reduction technologies reported savings of more than $802 million in additional natural gas sales.[10]

[8] Nathanial Gronewold, Greenwire, "Industry Spotlighting Efforts to Curb Fugitive Emissions", May 19, 2009.
[9] U.S. EPA, Natural Gas STAR Program, available at http://www.epa.gov/gasstar/. Based on a thirty percent reduction from 2008 emission levels.
[10] EPA Natural Gas STAR, Accomplishments, available at http://www.epa.gov/gasstar/accomplishments/index.html, last visited December 14, 2009.

A recent study estimated methane losses during well completions, production, processing and transmission in the Barnett Shale alone were 13.1 Bcf/yr, or about 1 percent of total gas production. At $3.50/Mcf, a low price that is conservative in estimating economic impacts; this amounts to $46 million per year in lost revenues for producers.

Source: Al Armendariz, Ph.D., *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*, 6 (Jan. 26, 2009).

This analysis examines the immense opportunity that greater implementation of cost-effective technologies and best management practices provides to achieve significant air pollution reductions to protect human health and the environment. EPA has committed to review, and if appropriate revise, the New Source Performance Standards ("NSPS") specific to natural gas plants and National Emission Standards for Hazardous Air Pollutants ("NESHAP") for process vents on glycol dehydrators, storage vessels with the potential for flash emissions, and certain equipment located at gas processing plants in the Crude Oil and Natural Gas Production, Transmission and Storage major source categories.[11] As part of that process we urge EPA to broaden the scope of federal clean air requirements to apply to a greater number of emissions sources and air pollutants within the oil and gas industry to ensure rigorous protections for human health and the environment under its existing authority in sections 111 and 112 of the Clean Air Act. To that end, we include here specific recommendations for the reduction of VOCs, methane and air toxics from discrete emission points in the oil and natural gas exploration, production, processing, storage and transmission sectors based on policies instituted

[11] Consent Decree, *Wildearth Guardians et al. v. Lisa P. Jackson*, 1:09-cv-00089 (CKK) (Feb 4, 2010).

or proposed at the state level or established technologies developed by industry in conjunction with EPA's Natural Gas STAR program.[12]

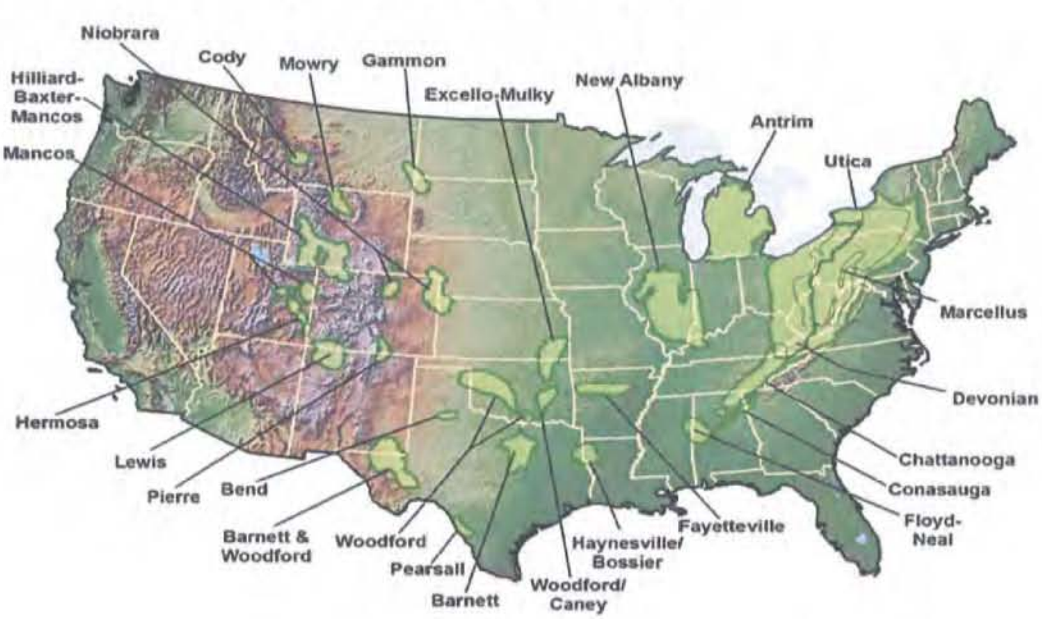
II. BACKGROUND

A. NATIONAL SCOPE OF OIL AND GAS DEVELOPMENT

Until recently, oil and gas activities have concentrated in certain pockets of the U.S. such as the Rocky Mountain states, Alaska and Texas. This is quickly changing, however, as technological developments such as horizontal drilling and hydraulic fracturing have made feasible the extraction of previously untapped unconventional resources located in difficult to reach geologic formations such as shales. As the following map shows, gas shales are located throughout the United States including in and around densely populated major metropolitan areas, important watersheds and environmentally sensitive areas.

[12] We do not include recommendations specific to NOx reductions here because EPA has recently revised the standards applicable to engines used in the oil and gas industry. Nevertheless, we include certain oil and gas NOx production emission estimates to provide a comprehensive picture of the significant contribution oil and gas activities make to air pollution.

Figure 2: Map of United States Natural Gas Shale Plays



For example, the Barnett Shale in Texas lies just outside the Dallas Fort-Worth metropolitan area. The Barnett Shale has an area of approximately 5,000 square miles with total technically recoverable resources estimated at 44.8 trillion cubic feet ("Tcf"). Natural gas production in the Barnett has increased rapidly since 1999, and as of May 10, 2010, 13,902 oil and gas wells had been installed and another 3,333 wells were pending.[13] Gas production in 2009 was nearly 1.8 Tcf.

The Haynesville shale, located east of the Barnett, has total technically recoverable resources estimated at 251 Tcf in an area that encompasses 9,000 square miles.[14] Future development activity in the Haynesville could equal that in the Barnett if well productivity and

[13] Railroad Commission of Texas, "Barnett Shale Information", http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf.

[14] ENVIRON, Draft Report, Development of Emissions Inventories for Natural Gas Exploration and Production Activity in the Haynesville Shale, 15 (August 31, 2009).

Oil and gas development is responsible for a host of other non-air quality related impacts. These impacts include:

- surface disturbances in the form of additional roads, vehicles, heavy machinery and drilling waste that interfere with wildlife habitat and migration routes and impair recreational use and enjoyment of some of the nation's most scenic and wild places;
- significant water use which can strain limited water resources in arid or highly-allocated areas;
- pollution of water resources including drinking water.

National attention has recently focused on the highly controversial practice of hydraulic fracturing or "fracking." Fracking involves injecting chemicals and water into natural gas shale formations in order to fracture the shale and release gas trapped in small fissures. In addition, fracking exposes underground aquifers and nearby wells to potential contamination from the numerous unknown chemicals used in the process. No one knows precisely which chemicals are used in fracking since the oil and gas industry obtained an exemption from the requirements of the Safe Drinking Water Act in 2005 that would have required disclosure of the constituents used in hydraulic fracturing. The seriousness of the full suite of impacts associated with oil and gas activities merits close attention by national policy-makers including restoring the public's right-to-know what chemicals are used in fracking.

well economics prove to be comparable.[15] If so, there could be over 10,000 active wells in the Haynesville by 2020.[16]

The Fayetteville Shale, located in the Arkoma Basin of Northern Arkansas and eastern Oklahoma, is equal to the Haynesville in area. As of April 2009 there were 1,000 active wells producing 88.85 billion cubic feet ("Bcf") of gas. It is estimated that there are 41.4 Tcf of technically recoverable resources in the Fayetteville.[17]

The Marcellus Shale is by far the largest of the domestic shale plays, spanning 95,000 square miles across six northeastern states. One estimate of the gas-in-place is 1,500 Tcf. Total technically recoverable resources are estimated to equal approximately 262 Tcf, but it is likely that this estimate will get revised upward as production in the shale increases.

B. OIL AND GAS ACTIVITIES EMIT METHANE THAT CONTRIBUTES TO CLIMATE CHANGE AND GROUND-LEVEL OZONE POLLUTION

1. Oil and Gas Activities Emit Significant Emissions of Methane

Emissions from oil and gas activities contribute significantly to atmospheric levels of methane. Current estimates, which are acknowledged to seriously under-estimate actual emissions, indicate that national oil and gas activities produced 125.5 MMT CO_2e in 2008. Rough emissions estimates and projections prepared for key gas and oil producing states reflect

[15] *Id.* at *15.*
[16] *Id.* at *18.*
[17] U.S. DOE, Modern Shale Gas, Development in the United States, A Primer, 19 (April 2009).

this sector's significant contribution to U.S. methane emissions. These inventories, prepared by the Center for Climate Studies ("CCS"), also likely underestimate emissions as they are also based on aggregate industry-average emission factors. Specific information related to industry activity such as the number of wells, gas processing plants and miles of pipeline is based on data obtained from the U.S. Energy Information Administration and American Gas Association's annual publication, Gas Facts.[18]

According to the CCS inventory for the state of Colorado, methane emissions from oil and gas activities accounted for 4.6% of Colorado's total GHG emissions in 2000 and are expected to make up 5.1% by 2020.[19] In Wyoming, oil and gas methane emissions are projected to total 6.3 MMT CO_2e in 2020 or 9.7% of the state's greenhouse gas emissions. This represents over a 50% increase from 2000 emissions of 2.8 MMT CO_2e.[20] In Montana natural gas production is projected to increase 74% from 2010 to 2020 assuming development of the state's extensive untapped Bakken gas shale and coal-bed methane reserves.[21] This would result in methane emissions from oil and gas activities more than doubling from 3.3% of the state's total greenhouse gas emissions in 2000 to 7.2% in 2020. In Dallas Fort-Worth, Texas, total greenhouse gas emissions in 2009 from Barnett Shale activities, which include fugitive methane and combustion CO_2 emissions, were anticipated to equal 33,000 tons per day of CO_2 equivalent,

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[18] CCS emissions estimates are based on "multiplying emissions-related activity levels (e.g.: miles of pipeline, number of compressor stations) by aggregate industry-average emission factors." Specifically, methods for estimating methane emissions were based on EPA's State Greenhouse Gas Inventory Tool, with reference to the Emissions Inventory Improvement Project. Projections are based on estimated consumption and projection levels. For example, Colorado projections assumed that natural gas production continued at a rate of 7.3% annually until 2009 and then followed US DOE regional projections until 2020 which average 0.8% annual growth. These inventories necessarily contain a number of uncertainties and therefore provide only approximations of emissions.
[19] Center for Climate Studies, Colorado GHG Inventory and Reference Case Projections, 1990-2020 (October 2007), Appendix E.
[20] Center for Climate Studies, Wyoming GHG Inventory and Reference Case Projections, 1990-2020 (Spring 2007), E-7.
[21] Center for Climate Studies, Montana GHG Inventory and Reference Case Projections, 1990-2020 (Spring 2007), 47. According to the U.S.G.S. the Bakken shale has 3.65 billion barrels of oil, 1.85 Tcf of natural gas and 148 million bbls of natural gas liquids in technically recoverable resources. Modern Gas Shale, A Primer, *supra* note 17, at 13.

approximately equal to the expected greenhouse gas emissions from two 750 MW coal-fired power plants.[22]

Continued development of U.S. shales and other nonconventional resources is likely to lead to an increase in the actual volume and relative contribution of methane emissions from oil and gas activities. According to the U.S. Department of Energy, shale and other unconventional natural gas development will continue to rise through 2030.[23]

2. *Methane Emissions Contribute Directly to Climate Change*

Methane's direct contribution to climate change -- both in terms of its potency and its growing presence in the atmosphere -- underscore the importance of smart policy action to secure immediate emission reductions from oil and gas activities. Methane is an extremely potent greenhouse gas. Over a 100-year period, methane has a warming potential 21 times that of carbon dioxide. However, when viewed over the short-term (20 years), methane is 72 times more effective at trapping heat than the same molecule of CO_2.[24] In addition, methane emissions are on the rise, having increased by 150% in the last two-hundred and fifty years. As a result of these increases we are currently experiencing the highest levels of atmospheric methane in the past 800,000 years.[25]

3. *Methane Contributes Indirectly to Climate Change by Contributing to Ground-Level Ozone Pollution*

Methane also contributes indirectly to climate change by contributing to the production of ground-level ozone.[26] As explained in more detail below in section C.1., ground-level ozone is associated with a host of serious public health and environmental problems, including respiratory

[22] Armendariz, *supra* note 6, at 1.
[23] U.S. DOE, Annual Energy Outlook 2010, Early Release Overview, 9 (December 2009).
[24] IPCC, 2007: Summary for Policymakers at 7.7, *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (2007).
[25] Nature, *Paleoclimate: Windows on the Climate, available* at http://www.nature.com/nature/journal/v453/n7193/full/453291a.html.
[26] Fiore *et al.*, and Katzenstein *et al.*, *supra* note 2.

disease, premature death, and climate change. After carbon dioxide and methane, ground-level ozone is the third-largest contributor to global warming.[27] Like methane, ozone levels are rising, having increased by 36% since pre-industrial times, much of which can be attributed to methane emissions.[28]

4. Methane Reductions Are A "Win/Win"

Reducing atmospheric levels of methane accomplishes the dual goal of combating climate change in the near term and reducing ozone pollution. As documented in an extensive scientific report by the U.S. Climate Change Science Program, methane reductions improve air quality by decreasing atmospheric levels of ozone: "[D]ecreases in methane emissions lead to reduced levels of lower atmospheric ozone, thereby improving air quality."[29] Indeed, one study on the relationship of methane emissions to ground-level ozone concludes that "tropospheric O_3 [ozone] responds approximately linearly to changes in CH_4 [methane] emissions over a range of anthropogenic emissions…."[30] Another found that reducing global anthropogenic methane emissions by 20% beginning in 2010 would result in a decrease in maximum daily surface ozone concentrations by 1 part per billion (ppb), over an 8-hour average.[31] The study predicted, based on epidemiological studies, this reduction in maximum ozone concentrations would prevent

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[27] P. Forster, *et al.*, 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA at 152, *available at* http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.
[28] U.S. EPA, TECHNICAL SUPPORT DOCUMENT FOR ENDANGERMENT ANALYSIS FOR GREENHOUSE GAS EMISSIONS UNDER THE CLEAN AIR ACT, Sixth Order Draft, 14 (June 21, 2008); Kirk R. Smith, et al, Health and Climate Change, PUBLIC HEALTH BENEFITS OF STRATEGIES TO REDUCE GREENHOUSE GAS EMISSIONS: HEALTH IMPLICATIONS OF SHORT-LIVED GREENHOUSE POLLUTANTS, 4 (Nov. 25, 2009). In addition to methane, NOx emissions from fossil-fuel burning is a primary contributor to rising atmospheric ozone levels.
[29] Hiram Levy II *et al.*, U.S. CLIMATE CHANGE SCIENCE PROGRAM SYNTHESIS AND ASSESSMENT PRODUCT 3.2, CLIMATE PROJECTIONS BASED ON EMISSIONS SCENARIOS FOR LONG-LIVED AND SHORT-LIVED RADIATIVELY ACTIVE GASES AND AEROSOLS 64 (Sept. 2008).
[30] Fiore *et al.*, *supra* note 2, at 1.
[31] West J. Jason *et al.*, Global Health Benefits of Mitigating Ozone Pollution with Methane Emissions Controls, PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES, Vol. 103, at 3988 (Mar. 16, 2006).

about 30,000 premature deaths from all causes in 2030 and approximately 370,000 premature deaths between 2010 and 2030.[32]

In addition, reducing methane emissions is a highly effective way to reduce levels of atmospheric greenhouse gases over the next few decades. Both methane and ozone are short-lived greenhouse gases; methane emissions last ten to twelve years in the atmosphere while ozone lasts only weeks to months. For these reasons, a number of prominent health and scientific experts have delineated a two-pronged climate approach that calls for reductions of methane as well as CO_2. According to such experts, "[A]ggressive policies directed towards carbon dioxide reduction, although necessary for the long term, are by themselves insufficient to reduce the rate of warming in the next few decades because of the long atmospheric lifetime of this gas. Thus, governments will need to reduce warming from short-lived greenhouse gas pollutants when considering climate change mitigation policies."[33]

5. Climate Change is Advancing Rapidly

The impacts caused by unprecedented atmospheric levels of greenhouse gases are happening at an alarmingly rapid pace. A recent report by the U.S. Global Change Research Program demonstrates that impacts already are occurring today across the United States, threatening human health, our natural resources and important economic industries. These, and future projected impacts, include:

- <u>Impacts to Human Health:</u> All Americans face increased health threats due to climate change. Heat waves, which are among the top causes of deaths due to

[32] *Id.* at 3992.

[33] Kirk R. Smith, *et al*, *supra* note 28, at 4. *See also* Hiram Levy II et al., *supra* note 29, at 64 (finding that "both [the] direct methane and indirect ozone decreases lead to reduced global warming.") and Stacy C. Jackson, "Parallel Pursuit of Near-Term and Long-Term Climate Mitigation", 326 SCIENCE 526 (Oct. 23, 2009).

natural hazards, are likely to increase in "frequency, severity, and duration." [34] The number of heat-wave related deaths in Chicago is projected to double or quadruple by 2050, and increase by two, three, five or seven times in Los Angeles, depending on various emissions scenarios.[35] Importantly, the number of deaths likely to occur due to rising temperatures is projected to outweigh any reduction in cold-weather related deaths due to warming temperatures.[36] Currently, 158 million people live in areas with air quality that fails to meet national health-based standards.[37] This number is expected to rise as warmer temperatures are associated with increased air pollution, especially ozone. Days when ozone levels have reached unhealthy levels for all people are expected to increase by 68% by mid-century in eastern cities under constant emissions.[38] EPA recently concluded that "climate change has the potential to produce significant increases in near-surface O_3 concentrations throughout the United States."[39] Increased wildfires will also contribute to deteriorating air quality, especially in the West.[40] Severe precipitation events are likely to strain urban sewer and stormwater systems beyond their capacities, threatening drinking water and recreational beach goers.[41] In Chicago, the frequency of such events is likely

[34] U.S. Global Change Research Program, CLIMATE CHANGE IMPACTS OF THE UNITED STATES, THE POTENTIAL CONSEQUENCES OF CLIMATE VARIABILITY AND CHANGE, 91 (2009). http://downloads.globalchange.gov/usimpacts/pdfs/climate-impacts-report.pdf.
[35] *Id.*
[36] *Id.*
[37] *Id.* at 92.
[38] *Id.* at 94.
[39] U.S. EPA, ASSESSMENT OF THE IMPACTS OF GLOBAL CHANGE ON REGIONAL U.S AIR QUALITY: A SYNTHESIS OF CLIMATE CHANGE IMPACTS ON GROUND LEVEL OZONE, xxiii (April 2009).
[40] U.S. Global Change Research Program,, *supra* note 34, at 95.
[41] *Id.* at 94.

to increase by 50 to 120% by the end of the century.[42] Diseases carried by food, water and animals such as West Nile, Giardia, Rocky Mountain spotted fever and Salmonella are likely to increase due to warmer temperatures and floods.[43]

- Impacts to Coastal Areas: Sea levels are expected to rise three to four feet this century, increasing the risk of flooding in portions of Boston, New York and New Orleans.[44] Non-native species are already threatening marine ecosystems such as the San Francisco bay fishery that provide important economic benefits to the Bay Area region.[45] Marine species and coral reefs, already under threat from pollution and over-fishing, are likely to suffer greater losses from the weakening effects of ocean acidification and warmer temperatures. Long-standing economic foundations of many local communities, such as the Maine lobster and Northeast Cod, are likely to experience significant setbacks as these species shift north in search of cooler waters.
- Impacts to the Northeast: Inhabitants of the Northeast are likely to experience greater and longer heat-waves, deteriorating air quality, increased droughts, and a decline in traditional agricultural economies. The residents of Boston, New York, Philadelphia and other eastern sea-board cities are likely to experience approximately 30 days or more of temperatures over 100 degrees Fahrenheit during summertime under a higher emissions forecast.[46] At the same time, air quality in these cities is expected to deteriorate, aggravating conditions that can lead to cardiac and pulmonary diseases and disorders. Droughts lasting one to

[42] *Id.* at 95.
[43] *Id.* at 96
[44] *Id.* at 150.
[45] *Id.* at 151.
[46] *Id.* at 107.

three months are projected to occur in the Catskills and Adirondacks.[47] Vermont's maple syrup and the Northeast dairy industry are projected to experience severe economic declines as maple trees shift north and cattle contend with warmer temperatures that decrease productivity and fertility.[48]

- Impacts to the Southwest and Western United States: The Southwest and Western United States are already experiencing an increase in droughts, forest fires, pest outbreaks, and declining air quality. Reduced snowpack, earlier snowmelt and decreased summer flows are placing additional strains on the region's over-allocated water resources. Large swaths of native forest are being lost to the pine and spruce beetles whose populations have thrived during the unusually warmer winters of the last decades. Over 1.5 million acres of lodgepole pine in Colorado, and significant numbers of pinion pine in the Southwest have been lost to beetle and other insect outbreaks caused by warmer weather and droughts.[49] Warmer temperatures, in combination with land-use patterns, have led to more favorable conditions for fires which are projected to increase and spread more rapidly. Important winter snow industries are likely to experience shorter seasons in higher elevation areas, while resorts in lower elevations may cease to exist entirely. Cultivation of certain crops, like California's apricots, almonds, walnuts and olives that require a certain number of cold days and nights, will become increasingly difficult and/or expensive.[50]

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[47] *Id.*
[48] *Id.* at 108.
[49] *Id.* at 82.
[50] *Id.* at 134.

- Impacts to Alaska. Alaska has warmed at more than twice the rate of the rest of the United States and temperatures are projected to continue to increase by anywhere between 5 and 13 degrees Fahrenheit by the end of the century. Sea ice and permafrost are disappearing, causing species displacement and significant economic harms. Key fisheries, such as the pollack, halibut and snow crab, have already begun migrating further from existing ports and processing infrastructure and are expected to continue to do so as the location, timing and composition of their food source changes due to retreating ice.[51] It is estimated that the repairs to crumbling infrasture due to permafrost melt will cost between $3.6 and $6.1 billion by 2030.[52] Lakes in the National Wildlife Refuges that provide important habitat and native hunting grounds are disappearing.[53] Alaska has lost over 2.5 million acres of white spruce to the spruce beetle. Some of the worst wild fires on record occurred in 2004 and 2005, burning large swatches of the state and causing significant degradation to the air quality in the city of Fairbanks.[54]
- Impacts to Ecosystems. Natural ecosystems are most vulnerable to climate change impacts as their ability to adapt to the rapid pace of warming is limited. Infectious diseases, wildfires, pest outbreaks and invasive species are likely to increase with climate change. Many plants and animals have begun their migrations north and to higher elevations but it is unlikely that most species will be able to adapt quickly enough. Northwest salmon and wild trout are likely to

[51] *Id.* at 144.
[52] *Id.* at 142.
[53] *Id.* at 141.
[54] *Id.*

decline by anywhere from 40 to 90 percent in certain places.[55] For certain species already living at the boundary of their habitat, such as the pika, grizzly bear and bighorn sheep, the invasion by low-land species is likely to cause significant resource conflict.[56] Many species will be lost, as is already starting to be seen in parts of the Arctic and Alaska. It is estimated that the Alaskan polar bear population will be gone within 75 years along with two-thirds of the world's polar bear population by 2050.[57]

C. OIL AND GAS ACTIVITIES EMIT VOC'S AND NOX THAT CONTRIBUTE TO GROUND-LEVEL OZONE POLLUTION.

1. Ozone is Harmful to Human Health and Welfare

Oil and gas activities emit significant amounts of VOCs, NOx and methane that contribute to local, regional and global background ground-level ozone pollution. Ozone has been linked with a number of serious public health impacts. Adverse effects that have been observed in controlled exposure and field/panel studies include respiratory effects (e.g., reduced pulmonary function), among healthy individuals, as well as children and adults with asthma, exposed acutely for 1-8 hours to the current health-based standard while physically active.[58] Sensitive individuals are affected at concentrations substantially below the current standard.[59] A number of studies have confirmed that ozone exposure is associated with premature mortality.[60] Higher temperatures are likely to exacerbate ozone air pollution and related health problems.[61]

[55] *Id.* at 87.
[56] *Id.* at 86.
[57] *Id.* at 85.
[58] U.S. EPA, National Center for Environmental Assessment-RTP Office, Office of Research and Development, 2006 Air Quality Criteria for Ozone and Related Photochemical Oxidants, February 2006.
[59] *Id.*
[60] Bell ML, Peng RD, Dominici F. 2006, *The Exposure-response Curve for Ozone and Risk of Mortality and the Adequacy of Current Ozone Regulations*, 114 Environ. Health Perspect., 532-536; Bell ML, McDermott A, Zeger SL, Samet JM, Dominici F., 2004. *Ozone and Short-term Mortality in 95 U.S. Urban Communities*, 1987-

Ozone pollution also threatens the ecological health of natural resources such as National Parks, forests and important agricultural commodities. EPA recently proposed a distinct ozone standard aimed at reducing the harmful welfare effects caused by ozone's deleterious impacts on vegetation, forests and agricultural crops.[62] According to EPA, impacts associated with ozone pollution include: reduced root and tree growth; increased rates of senescence; decreased plant vitality and a greater susceptibility to disease and infestation; and visible leaf damage.[63] Loss of forests may also exacerbate climate change because trees act as natural carbon sinks, absorbing carbon dioxide emissions through the process of photosynthesis, thereby reducing the amount of greenhouse gases in the atmosphere.[64]

Currently, two-thirds of our National Parks suffer from ozone pollution that can harm the park's natural resources.[65] Ozone levels are significant or increasing in a number of parks and in remote areas near significant oil and gas activity such as Rocky Mountain National Park, Mesa Verde, Glacier and in rural parts of Wyoming, Colorado and New Mexico.[66]

2. *Oil and Gas Activities Emit Significant Amounts of Ozone Precursors*

Inventories prepared in key oil and gas basins across the Intermountain West and Gulf region demonstrate that oil and gas activities are a significant source of tropospheric ozone pollution. *See* Appendix A for a summary of VOC and NOx emissions from six basins in the

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2000, JAMA, 292(19): 2372-2378; Levy JI, Chemerynski SM, Sarnat JA. 2005, *Ozone Exposure and Mortality: An Empiric Bayes Metaregression Analysis*, Epidemiol, 16(4):458-468.

[61] Kirk R. Smith, *et al.*, *supra* note 28, at 2.

[62] U.S. EPA, Proposed Rule, *National Ambient Air Quality Standards for Ozone*, 75 Fed. Reg. 2938 (January 19, 2010).

[63] *Id.*

[64] *Id.*; *See also* Zack Parsons and Steven Arnold, Colorado Department of Health and Environment, *Ozone Transport in the West: An Exploratory Study* (July 2004), *available at* http://www.cdphe.state.co.us/ap/down/ozonetransport.pdf at 9.

[65] National Park Service, AIR QUALITY IN NATIONAL PARKS, 2008 ANNUAL PERFORMANCE AND PROGRESS REPORT, 1 (Sept. 2009).

[66] *Id.* at 12; *see also* Colorado OGCC Cost-benefit and regulatory analysis for Rule 805, at 3.

west and the Haynesville Shale in Texas and Louisiana. Information on emissions from the Barnett Shale is provided separately below. Emissions information for the Marcellus Shale is not yet available. Such information is urgently needed however as development of this massive shale is marching forward rapidly.

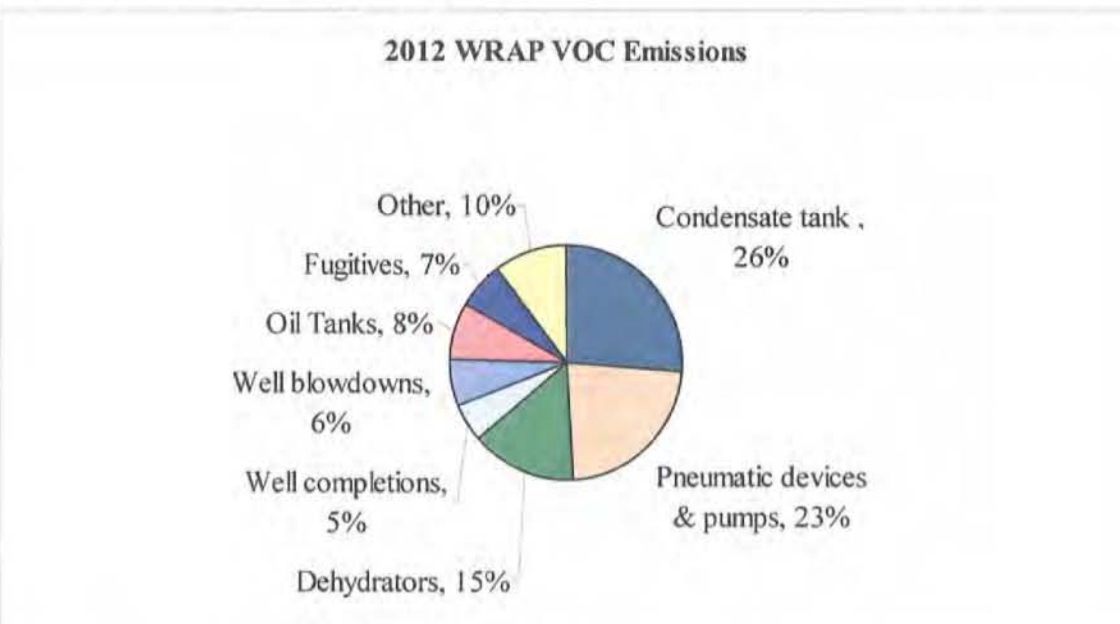
The Western Regional Air Partnership ("WRAP"), in conjunction with the Independent Petroleum Association of Mountain States, conducted an updated inventory of oil and gas exploration and production NOx and VOC emissions across six basins in Colorado, Wyoming, Utah and New Mexico.[67] The inventory estimated 2006 baseline emissions using information related to well activity and production data obtained from participating oil and gas companies operating in each basin and state regulatory databases. The inventories project 2010 or 2012 emissions based on anticipated rates of production activity provided by participating oil and gas companies and historical production trends. Projected emissions take into consideration federal and state "on-the-books" regulations that apply to oil and gas exploration and production activities.[68] These inventories provide information on basin-wide exploration and production NOx and VOC emissions as well as emissions from specific oil and gas sources. Although limited in geographic scope, the WRAP data is an informative tool for policy decisions as it helps identify significant sources of ozone precursors in the oil and gas exploration and production sectors.

[67] Initially the project was intended to encompass all oil and gas basins in Utah, Montana, Wyoming, Colorado, New Mexico and North Dakota. To date, inventories for six basins have been completed. VOC emissions from the North San Juan Basin in Colorado are not included here as they are considerably smaller due to the small amount of drilling still occurring, and the low VOC content of produced gas from the predominant resource in the basin, coal-bed methane. For more information *see* ENVIRON, Development of Baseline 2006 and Midterm 2012 Emissions from Oil and Gas Activity in the North San Juan Basin, 21 (Sept. 1, 2009). All WRAP inventories cited herein are available at http://www.wrapair.org/forums/ogwg/PhaseIII_Inventory.html.

[68] For example, projected emissions for CO's D.J. basin take into consideration NSPSs for all new nonroad engines, nonroad diesel fuel sulfur standards and tier 1-4 standards for drill rigs as well as CO's rules for glycol dehydrators and condensate tanks contained in Regulation 7. ENVIRON, Development of 2010 Oil and Gas Emissions Projections for the Denver-Julesburg Basin, 17 (April 30, 2008).

As graphically depicted in the pie chart below, the data from the WRAP inventories indicate that glycol dehydrators, condensate tanks and pneumatic devices account for the majority of projected VOCs at exploration and production sites. Well completions are a significant source of 2006 emissions (11%) but their share of total VOC emissions decreases by 2012. Engines used to power compressors are the primary source of NOx. Emissions from drill rigs are also a significant source of NO_X emissions during oil and gas field development, with environmental impact statements prepared by the Bureau of Land Management for gas fields in Wyoming such as the Pinedale Anticline field showing NOx emissions from drill rigs are the largest source of NOx emissions.

Figure 3: Percent Contribution of Estimated Volatile Organic Compounds from Oil and Gas Exploration and Production Sources in the D.J., Piceance, North and South San Juan, Uinta and Wind River basins (2012).



For example, in the Piceance basin in Colorado, venting from initial well completions and blowdowns, and emissions from glycol dehydrators and pneumatic devices make up 60% of the total 2012 emissions. Of these, venting from initial completions is the most significant source, accounting for 23% of total VOC emissions.[69] The remainder of emissions comes from condensate tanks (14%), glycol dehydrators (8%), pneumatic pumps/devices (8%), compressor engines (5%) and other fugitive sources (4%). Compressor engines emitted an estimated 5,705 tons of NOx in 2006 (46% of total NOx emissions) and are projected to emit 6,497 tons in 2012 (64% of total NOx emissions).[70] Notably, in 2006, oil and gas exploration and production activities were the single largest anthropogenic source of VOCs in Garfield County, totaling an estimated 27,464 tons and comprising 37% of emissions.[71]

Large condensate tanks and pneumatic devices are projected to account for the largest share of VOCs in Colorado's DJ basin in 2010 (45% and 17% respectively) in 2010.[72] The most significant source of NOx emissions are compressor engines which accounted for 55% of total NOx emissions in 2006 and are projected to account for 52% in 2010.[73]

Oil and gas production in the South San Juan basin in New Mexico has been declining since the mid-1990s and is projected to remain flat though 2012. While total VOC emissions from oil and gas activities in this basin are expected to decrease from 60,697 Tpy in 2006 to 55,705 Tpy in 2012, these oil and gas discharges represent a major source of VOCs. NOx

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[69] ENVIRON, Development of 2010 Oil and Gas Emissions Projections for the Piceance Basin, 46 (January 21, 2009). The projections do not include potential reductions that may occur due to the implementation of COGCC rules for the control of odors from oil and gas activities that took effect in 2009.
[70] *Id.* at 47.
[71] Garfield County Public Health, Air Quality Management in Garfield County, Colorado's Most Active Energy Development Region, 7 (Oct. 22, 2009).
[72] Development of 2010 Oil and Gas Emissions Projections for the Denver-Julesburg Basin, *supra* note 69, at 21.
[73] *Id.* at 22; ENVIRON, Development of Baseline 2006 Emissions From Oil and Gas Activity in the Denver-Julesburg Basin, 29 (April 30, 2008).

emissions are projected to rise slightly from 38,788 to 39,774.[74] Venting from blowdowns is projected to be the largest source of VOC emissions, accounting for 23% of total 2012 VOC emissions, followed by emissions from dehydrators (20%) and venting from initial completions (17%).[75] NOx emissions from compressor engines are projected to account for 85% of all 2012 emissions, equaling 34,212 tons.[76]

Emissions from oil and natural gas production in the Uinta basin in Utah are projected to rise significantly from 71,546 Tpy of VOCs and 13, 093 Tpy of NOx in 2006 to 127, 495 Tpy of VOCs and 16,547 Tpy of NOx in 2012 consistent with an increase in production.[77] Emissions from glycol dehydrators and flashing emissions from condensate and oil tanks are projected to make up to 57% of the total VOC emissions in the Uinta basin in 2012.[78] Drill rigs are projected to be the largest source of NOx emissions, followed closely by compressor engines.[79]

In the only basin inventoried for WY to date, the Wind River basin, pneumatic devices account for the largest percentage of VOC emissions (53% in 2006 and 59% in 2012), followed by venting from blowdowns (17% in 2006 and 15% in 2012).[80] Emissions from compressor engines account for the vast majority of NOx emissions (71% in 2006 and 63% in 2012), followed by those from drill rigs (12% in 2006 and 16% in 2012).[81] While not available yet,

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[74] ENVIRON, Final Report, Development of Baseline 2006 Emissions From Oil and Gas Activity in the South San Juan Basin, 44 (Nov. 25, 2009); ENVIRON, Development of 2010 Oil and Gas Emissions Projections for the South San Juan Basin, 26 (Dec. 8, 2009).

[75] Development of 2010 Oil and Gas Emissions Projections for the South San Juan Basin, *Id.* at 24.

[76] *Id.* at 26.

[77] ENVIRON, Final Report, Development of Baseline 2006 Emissions From Oil and Gas Activity in the Uinta Basin, 39-40 (March. 25, 2009); ENVIRON, Development of 2010 Oil and Gas Emissions Projections for the Uinta Basin, 51-52 (March 25, 2009).

[78] Development of 2010 Oil and Gas Emissions Projections for the Uinta Basin, *Id.* at 46.

[79] *Id.* at 51.

[80] ENVIRON, Final Report, Development of Baseline 2006 Emissions From Oil and Gas Activity in the Wind River Basin, ES-4 (July 14, 2010); ENVIRON, Development of 2012 Oil and Gas Emissions Projections for the Wind River Basin, 24 (July 2010).

[81] Development of Baseline 2006 Emissions From Oil and Gas Activity in the Wind River Basin, *Id.* at 32; Development of 2012 Oil and Gas Emissions Projections for the Wind River Basin *Id.* at 34.

emissions from the massive gas fields in the Green River Basin in Wyoming are undoubtedly significant and the same is true for Wyoming's Powder River Basin.

Inventories prepared in basins outside the WRAP region also demonstrate the significant emissions associated with oil and gas exploration and production and transmission activities. A recent analysis of air emissions associated with natural gas and oil production in the Barnett Shale area found them to be comparable to the combined emissions from all the cars and trucks in the metropolitan area and several times higher than total emissions from the Dallas-Fort Worth area's airports.[82] The following chart demonstrates peak summertime daily emissions (tons per day) in 2009 from sources in the Barnett Shale.[83]

Table 2: Barnett Shale Peak Daily Summer Emissions of VOCs and NOx (tons per day)

Sources	VOC	NOx
Condensate and oil tanks	146	0
Production fugitives	26	0
Well drilling and completions	21	5.5
Gas processing	15	0
Transmission fugitives*	28	0
Compressor engine exhaust	19	46

*Transmission fugitives include emissions produced by the movement of natural gas from wells to processing plants and from processing plants to compressor stations.

VOC emissions in the Haynesville shale are predicted to range from approximately 12 to 29 tons per day ("Tpd") in 2012 to 19 to 69 Tpd in 2020 depending on the pace of

[82] Armendariz, *supra* note 6, at 24.
[83] *Id.* at 25.

development.[84] The low growth development scenario assumed that no new drill rigs were added to the region's drill count in 2009 (95 rigs in the shale). The aggressive scenario assumed the addition of 25 drill rigs each year, capped at 200, which is consistent with the historical pace of growth in the Barnett Shale between 2001-2009. The moderate scenario assumed a growth rate one half of the aggressive scenario (12 new drill rigs per year). The analysis projected natural gas production for each scenario based on the anticipated number of new active wells drilled by each additional rig (assuming that each rig drills a total of 5.8 wells a year, with a success rate of 55%) and well productivity rates based on typical well production in the shale. NOx and VOC emissions were estimated for each scenario using standard emissions factors.[85]

The 2012 NOx emissions are estimated to be 60.64, 81.72, or 139.84 Tpd in 2012 under low, moderate, and high development scenarios, respectively.[86] By 2020 these numbers are projected to increase to approximately 63, 127, and 267 Tpd.[87] Moderate development of the shale results in an additional 120 Tpd of NOx in northeast Texas and northwest Louisiana. This is equal to approximately half of the NOx emissions from all source categories (oil and gas and other) emitted in 2012 in the five Texas counties that comprise the Haynesville Shale.[88] According to the inventory, "if the development of the Haynesville Shale proceeds at even a relatively slow pace, emissions from exploration and production activities will be sufficiently large that their potential impacts on ozone levels in Northeast Texas should be evaluated."[89]

[84] Development of Emissions Inventories for Natural Gas Exploration and Production Activity in the Haynesville Shale, *supra* note 14, at Table 22, 45.
[85] *Id.* at 13-19.
[86] *Id.* at Table 22, 56.
[87] *Id.* at Table 23, 60.
[88] *Id.* at 63.
[89] *Id.* at 1.

D. OIL AND GAS ACTIVITIES EMIT AIR TOXIC POLLUTION

Oil and gas exploration activities emit a number of hazardous air pollutants known to cause cancer or other non-cancer health impacts. According to EPA, oil and gas production emits benzene, toluene, ethylbenzene, and xylenes as well as n-hexane.[90] Long-term exposure to benzene can cause cancer as well as blood disorders, and reproductive and developmental disorders. Exposure to benzene, as well as toluene, ethylbenzene, and xylenes also causes a host of non-cancer effects such as respiratory tract irritation, irritation to the skin, eyes, nose and throat, neurological problems, dizziness and headaches.

Many of the same sources that emit methane, NOx and VOCs also emit hazardous air pollutants. Studies conducted at various locations in Texas, Colorado and Wyoming have identified elevated levels of HAPs at exploration and production sites. For example, in the Barnett Shale, peak summertime HAP emissions were estimated to equal 17 Tpd in 2009.[91] Condensate tanks were the primary sources, emitting 11 Tpd, followed by compressor engine exhaust (3.6 Tpd). Fugitive emissions from production and transmission sources, as well as gas processing, well drilling, completion and hydraulic fracturing contributed the remainder.[92]

In March, 2010 the Texas Council on Environmental Quality ("TCEQ") measured benzene at levels above TCEQ's short term, health based comparison level of 180 parts per billion (ppb) at two exploration and production sites in the Barnett Shale in Wise County, Texas.[93] Air samples collected as part of a study by residents of the town of DISH, Texas located within the Barnett Shale, confirmed the presence of certain HAPs including benzene,

[90] U.S. EPA, Outdoor Air-Industry, Business and Home Oil and Natural Gas Production-Additional Information, http://www.epa.gov/air/community/details/oil-gas_addl_info.html#activity2.
[91] Armendariz, *supra* note 6, at Table 21-2, 24.
[92] *Id.* Production fugitives include emissions from components on wells such as casing heads, fittings, valves, and pneumatic devices.
[93] Railroad Commission of Texas, Notice to Oil, Gas & Pipeline Operators Regarding Air Emissions (March 2010).

carbon disulfide, carbonyl sulfide, naphthalene, and xylene at concentrations in excess of TCEQ short-term and long-term effects screening levels.[94]

Air monitoring conducted by Garfield County, Colorado reveals similar levels of ambient HAPs near exploration and production sites. Garfield County is home to the majority of oil and gas development in the Piceance basin. In response to 171 complaints regarding odors related to oil and gas operations, the County conducted an ambient air quality study to evaluate exposure to air toxics between 2005 and 2007.[95] The study identified 15 chemicals of potential concern in the collected samples including benzene, ethylbenzene, toluene, and m, p-Xylene. Benzene cancer and non-cancer risks were highest in the oil and gas areas. At one oil and gas site (the "Brock site") the cancer risk was slightly above the upper-end of EPA's acceptable range of 1 to 100 excess cancers per million individuals exposed. The high-end, short-term non-cancer hazards for benzene exposures also exceeded EPA's acceptable levels.[96] A subsequent risk assessment, based on the 2005-2007 air monitoring and supplemented by air modeling, indicated that benzene emissions from well completions, dehydration units and condensate tanks pose a cancer risk. According to the risk assessment, benzene emissions from uncontrolled flowback during well completions, dehydration units and condensate tanks pose the most significant cancer threats.[97]

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[94] Earthworks' Oil and Gas Accountability Project, Health Survey Results of Current and Former DISH/Clark, Texas Residents, 13 (December 2009), http://townofdish.com/objects/DishTXHealthSurvey_FINAL_hi.pdf.
[95] Air Resources Specialists, Inc., Air Quality Management in Garfield County: Colorado's Most Active Energy Development Region, 19 (Oct. 22, 2009). Pursuant to this study the County collected monthly 24-hour samples and quarterly samples from eight oil and gas sites, four urban sites and two background rural sites between 2005-2007.
[96] Raj Goyal, Air Toxic Inhalation: Overview of Screening-Level Health Risk Assessment for Garfield County, slide 27 (June 17, 2008), http://www.garfield-county.com/index.aspx?page=1334.
[97] Teresa Coons, Ph.d. and Russell Walker, "Community Health Risk Analysis of Oil and Gas Industry Impacts in Garfield County", xv. The risk assessment considered exposure to modeled benzene emissions based on sampling results over a 70-year period. It concluded that well emissions pose the greatest threat over this time-period but that exposure to emissions from glycol dehydrators and condensate tanks is more likely over seventy years.

Numerous HAPs have also been identified in the ambient air in and around the Pinedale-Anticline gas field in Sublette County, Wyoming. For example, recent air quality monitoring identified benzene at one monitor at levels higher than the Agency for Toxic Substances and Disease Registry's acute inhalation minimal risk level.[98] Wyoming is currently developing a risk assessment associated with emissions from sources in the Pinedale-Anticline gas fields.

E. COST-EFFECTIVE TECHNOLOGIES ARE AVAILABLE TO REDUCE METHANE, VOCS AND AIR TOXICS.

Nationwide implementation of oil and gas pollution controls will result in strengthened protection of human health and the environment from serious air pollutants as well as valuable energy savings that translate into more natural gas available to consumers, increased taxable revenue available to states or localities, and greater profits for gas companies. The following is a list of some of the most cost-effective technologies or practices that are available today.

1. Use of Low or No-bleed Pneumatic Devices.

Pneumatic devices are used throughout the production, processing and transmission of natural gas, and the production of crude oil, to automatically operate valves and control pressure, gas flow, temperature or liquid levels.[99] As the following chart illustrates, pneumatic devices account for the largest percentage of natural gas production fugitive emissions—nearly 4 times as much as the other leading causes of emissions.

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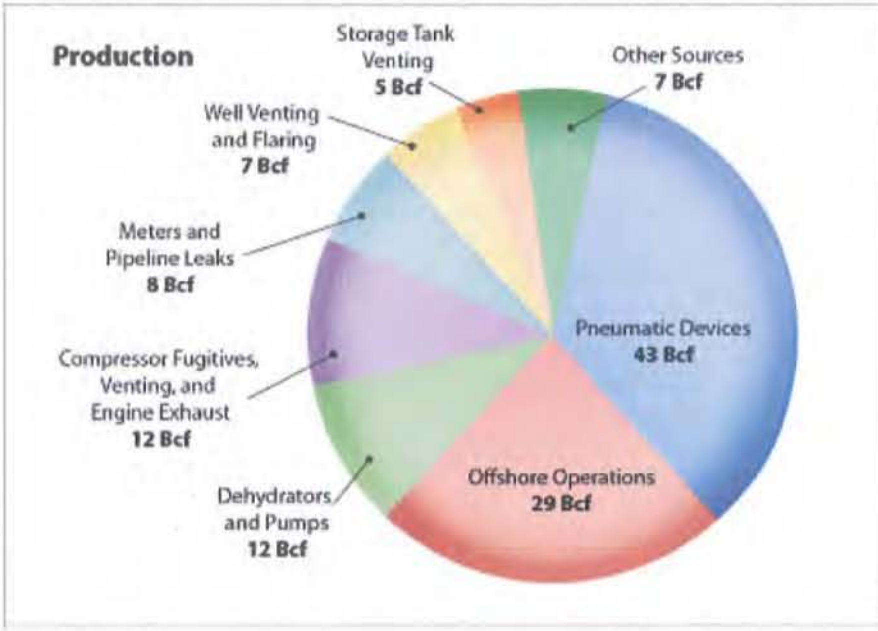
[98] Sublette County, Air Toxics Inhalation Project, 4th Quarter Data Summaries 2009, E-6. Ambient levels of Benzene at one monitor were 38.31 μg/m3. The ATSDR acute inhalation MLR for benzene is 20 μg/m3.
[99] *See* U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", *available* at http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf.

Figure 4: Oil and Natural Gas Production Sources of Methane Emissions



Source: EPA, http://www.epa.gov/gasstar/basic-information/index.html

In addition, pneumatic devices contribute to ozone pollution. For example, WRAP inventories of VOC emissions from oil and gas exploration and production activities in the Colorado D.J. and the Utah Uinta basins project that pneumatic devices will account for 17% and 20% of all VOC exploration and production emissions in 2010 and 2012, respectively.[100]

Pneumatic devices are designed to vent natural gas. However, some bleed or vent at rates significantly lower than others yet still achieve the same overall performance. Replacing high with low or no-bleed pneumatic devices results in significant gas savings and has a payback

[100] Development of 2010 Oil and Gas Emissions Projections for the Denver-Julesburg Basin, *supra* note 72, at 21; Development of 2010 Oil and Gas Emissions Projections for the Uinta Basin, *supra* note 78, at 46.

period of less than one year.[101] This practice has saved natural gas operators $61.2 million and as much as 20.4 Bcf of methane gas to date.[102]

Colorado requires that all new, replaced or repaired pneumatic devices at production facilities must be low or no-bleed.[103] In addition, all pneumatic controllers at exploration and production sites, upstream natural gas compressor stations, natural gas drip stations and gas processing plants located in an ozone nonattainment or attainment/maintenance areas must have VOC emissions equal to or less than a low-bleed controller.[104] All new pneumatic controllers and existing pneumatic controllers located at a modified facility in the state of Wyoming must be low or no-bleed or route discharge streams to a closed loop system.[105]

2. Well Completions

Well completion activities are another significant source of methane, VOCs and HAPs including benzene.[106] One cost-effective way to significantly decrease well emissions is to use portable or permanent equipment to recover, rather than release through venting or flaring, natural gas during the final well drilling process ("green or reduced emission completions"). EPA estimates $176 million (25.2 Bcf) of natural gas can be recovered annually using green completions.[107] Devon Energy, an operator in the Barnett Shale, reported the capture of 10.7 Bcf of gas between 2004 and 2009 through the use of "reduced emissions completions." In 2007

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[101] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf. EPA defines a high-bleed device as one that releases natural gas in excess of 50 Mcf a year.
[102] *Id.*
[103] CO Regulation 7, XVIII; Colorado Oil and Gas Conservation Commission rule 805(b)(2)(E).
[104] CO Regulation 7, XVIII.C. Upstream means upstream of natural gas processing plants.
[105] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (March 2010) ("WY Revised March 2010 Guidance"), http://deq.state.wy.us/aqd/oilgas.asp.
[106] For example, venting from well completions and re-completions are projected to account for 26% of VOC emissions in 2012 from the Piceance basin in Colorado and emissions from well completions and drilling were responsible for 21 tons per day of VOCs in 2009 in the Barnett Shale. Development of 2010 Oil and Gas Emissions Projections for the Piceance Basin, *supra* note 69, at 21; and Armendariz, *supra* note 6, at 25.
[107] U.S. EPA,"Opportunities for Methane Emissions Reductions from Natural Gas Production." Producer's Technology Transfer Workshop, 8 June 2006, available at http://www.epa.gov/gasstar/documents/workshops/midland-2006/gremillion.pdf.

alone, Devon claimed it prevented the release of over 6.4 Bcf of methane, generating an additional $38 million in revenue from increased sales of natural gas.[108]

Colorado currently requires the use of green completions on all oil and gas production wells unless not technically and economically feasible.[109] Wyoming has required the use of green completions in the Jonah-Pinedale Anticline Development Area ("JPAD") since 2007 and has recently expanded this requirement to all areas of concentrated oil and gas development (concentrated development areas or "CDA"s) in the state.[110] Montana requires that VOC vapors greater than 200 British thermal units per cubic foot from wellhead equipment with the potential to emit 15 tpy or greater be routed to a capture or control device such as a pipeline or flare.[111]

3. Glycol Dehydrators

Glycol dehydrators are widely used in the production, processing and transmission of natural gas to remove excess water from the gas. As part of the de-watering process, methane is vented to the atmosphere. EPA estimates that glycol dehydrators vent approximately 1 Bcf of methane to the atmosphere annually as well as significant amounts of HAPs and VOCs.[112] A number of technologies are available to reduce emissions from glycol dehydrators including installing flash tank separators, reducing the glycol circulation rate and using electric pumps instead of gas-assisted pumps.[113]

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[108] Devon press release, November 12, 2008.

[109] Final Rule, Colorado Oil and Gas Conservation Commission, § 805(b).

[110] WY Revised March 2010 Guidance, *supra* note 106, at 15.

[111] MT Admin. Rules § 17.8.1711. This rule applies to all oil and gas facilities that have the potential to emit 25 Tpy of a regulated air pollutant, including HAPs. Oil and gas facilities include wells and associated equipment used to produce, treat, separate or store oil, natural gas, or other liquids produced by the well. MT Ann. Code (2009) § 75-2-103.

[112] For example, dehydrators are expected to contribute 24% of all VOC emissions from exploration and production activities in the Uinta basin in 2012 and 11% of VOC emissions in the Piceance basin. Development of 2010 Oil and Gas Emissions Projections for the Uinta Basin, *supra* note 78, at 53 and Development of 2010 Oil and Gas Emissions Projections for the Piceance Basin, *supra* note 69, at 46.

[113] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators", 1, *available* at http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf.

In Colorado, oil and gas operators must control actual, uncontrolled VOC emissions of 15 Tpy or more from vents on glycol dehydrators (individual units or the aggregate emissions from all dehydrators at a site) located at all oil and gas exploration and production operations, natural gas compressor stations, drip stations or gas processing plants by 90%.[114] More stringent requirements apply to glycol dehydrators located within a one-quarter mile of a public place in Garfield, Mesa and Rio Blanco counties in the Piceance basin. Operators in these areas must control emissions of VOCs by 90% from all dehydrators with a potential to emit 5 Tpy of VOCs.[115]

Wyoming requires control of HAPs and VOCs by at least 98% at all new and existing dehydration units operating in the Jonah-Pinedale Anticline Development Area regardless of total actual or potential emissions.[116] All new and existing dehydrators in concentrated areas of development and statewide must control HAPs and VOCs by 98% upon the first date of production. Controls may be removed after one year if emissions equal to or less than 6 Tpy and units are equipped with still vent condensers.[117]

4. Crude Oil, Condensate and Produced Water Tanks

Field crude oil, condensate and produced water storage tanks used in the production, storage and transmission of natural gas and in oil production are another significant source of methane, VOCs and HAPs.[118] Flash emissions occur during the transfer of liquids from

[114] CO Regulation 7, XII.H.
[115] Final Rule, Colorado Oil and Gas Conservation Commission, § 805(b).
[116] WY Revised March 2010 Guidance, *supra* note 106, at 37.
[117] Alternatively, upon production units must be equipped with reboiler still vent condensers and glycol flash separators. If, after 30 days, potential VOCs $\geq$ 8 Tpy, operators must install combustion controls capable of reducing emissions by 98%. After one year, combustion units may be removed if total potential VOC emissions $\leq$ 8 Tpy.
[118] For example, peak 2009 summertime VOC emissions from condensate and oil tanks in the Barnett Shale reached 146 tons per day, comprise 33% of projected 2012 VOC emissions in the Uinta basin and 45% of projected 2010 VOC emissions in the D.J. basin. Armendariz, *supra* note 6, at 25; Development of 2010 Oil and Gas Emissions

separation equipment to atmospheric storage tanks. Breathing or standing losses occur when vapors are evaporated or displaced from tanks due to rising liquid level and changes in temperature.[119] Installation of vapor recovery units can capture approximately 95% of methane vapors (as well as other air pollutants) from storage tanks, save operators up to $260,060 per year, and has a payback of three months.[120]

Wyoming requires that VOC emissions from condensate, oil and produced water tanks located at new or modified facilities in the Jonah-Pinedale Anticline Development Area and concentrated areas of development must control flash emissions upon the first date of production regardless of the amount of emissions. These facilities may remove controls after one year if emissions are less than 8 Tpy of VOCs. Statewide, new and modified facilities must control VOC flash emissions equal to or greater than 10 Tpy by 98% upon FDOP and may remove controls after one year if emissions are less than 8 Tpy.[121]

Colorado currently requires the control by 95% of VOC emissions from condensate, crude oil and produced water tanks with a potential to emit 5 Tpy of VOCs that are located within a one-quarter mile of a public place in Garfield, Mesa and Rio Blanco counties in the Piceance basin.[122] Owners or operators of condensate tanks whose cumulative actual uncontrolled VOC emissions are equal to or greater than 30 Tpy located at exploration and production sites within ozone nonattainment areas and nonattainment/maintenance areas must

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Projections for the Uinta Basin, *supra* note 78, at 53; Development of 2010 Oil and Gas Emissions Projections for the Denver-Julesburg Basin, *supra* note 72, at 20.

[119] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Installing Vapor Recovery Units on Crude Oil Storage Tanks" 1, *available* at http://www.epa.gov/gasstar/documents/ll_final_vap.pdf.

[120] *Id.*

[121] Note that the emission threshold for the application of this requirement differs depending on an individual tank's location. For example, all tanks located in the Pinedale-Anticline Development Area must control emissions upon production, regardless of the amount of emissions. Tanks located in Concentrated Development Areas with potential and actual emissions of 8 Tpy must comply with specified emissions limitations whereas other tanks located statewide need only install control technologies if potential emissions equal 10 Tpy or more and actual emissions equal or exceed 8 Tpy. WY Revised March 2010 Guidance, *supra* note 105, at 18, 11, 5.

[122] Final Rule, Colorado Oil and Gas Conservation Commission, § 805(b).

meet declining emissions reductions over time. For example, such operators must reduce overall VOC emissions from all of their tanks emissions by 81% during the 2009 ozone season (May 1-Sept. 30) and by 85% in 2010 (such owners/operators do not need to apply controls to every individual tank). Owners or operators must reduce non-ozone season emissions by 70% in 2009 and 2010. Controls used to produce the requisite reductions must achieve a 95% control efficiency.[123] Additionally, tanks installed after February 1, 2009 controlled with a combustion device must be equipped with an auto-igniter upon startup. Statewide, new and existing condensate tanks that emit equal to or greater than 20 Tpy of VOCs must control emissions by 95%.[124]

Montana requires that VOC vapors greater than 200 British thermal units per cubic foot from wellhead equipment and oil and condensate storage tanks with the potential to emit equal to or greater than 15 tpy be routed to a capture or control device such as a pipeline or flare.[125]

> A TCEQ case study illustrates the cost savings that can be realized from pollution control technologies, in this instance a storage tank bhattery in North Texas releasing 190 Mcf/day of gas, with a heat content of 2400 Btu – 2.4 times higher than standard natural gas. Capturing the gas could have a monthly value of $68,000 (assuming $5/Mcf natural gas price adjusted for the higher heat content of the captured vent gas). In this case, the simple payback period for a vapor recovery unit costing $32,000 would be 14 days ($32,000/$68,000 per month = 14 days). Some vendors of vapor recovery technology also offer alternative financing options to the outright purchase of the equipment, including providing the equipment at no up-front cost in return for a share of the recovered product.

[123] CO Regulation 7, XII.D.1. *See also* Colorado DPH&E Air Pollution Control Division, Oil and Gas Exploration & Production Regulation No. 7 Requirements, http://www.cdphe.state.co.us/ap/sbap/SBAPoilgastankguidance.pdf.
[124] CO Regulation 7, XVII.C.1.
[125] MT Admin. Rules § 17.8.1711.

5. Production Fugitive Emissions

There are a large number of uncontrolled fugitive sources in the production sector. California's Climate Change Scoping Plan proposes to address fugitive emissions from the extraction process of the state's large oil and gas industry, including on and off-shore sources. These emissions are from well and process equipment venting: leaks of flanges, valves and other fittings on the wells and equipment; and from separation and storage units such as sumps and storage tanks. Controls for the fugitive sources range from applying simple fixes to existing technologies to deploying new technologies to replace inefficient equipment and detect leaks and would include: improving operating practices to reduce emissions when compressors are taken off-line; installing compressor rod packing systems; substituting high bleed with low bleed pneumatic devices; improving leak detection; installing electronic flare ignition devices; replacing older equipment (flanges, valves, and fittings); and installing vapor recovery devices. These are proven technologies according to the U.S. EPA's Natural Gas STAR program, which will pay back investments in a short period of time through saleable natural gas savings. California's proposal is expected to reduce fugitive methane emissions by approximately 0.2 MMT CO_2e per year, beginning in 2015 and result in net annualized savings of $3.7 million.[126]

6. Plunger Lifts and "Smart" Well Automation during Well Unloading

Operators often remove unwanted fluids from mature gas wells through "well unloading"- practices that lead to venting of methane, HAPs and VOCs. One way to remove unwanted fluids without venting while also improving well productivity is to install a plunger lift system and "smart" well automation system. Plunger lifts use gas pressure buildup in the well

[126] *See* California's Climate Change Scoping Plan, available at http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf, ES-5, 3, 54-56, and V. 1 of Appendices, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf, C153-154.

casing-tubing annulus to operate a steel plunger that pushes liquids to the surface.[127] Smart well automation maximizes the efficiency of plunger lifts by routinely varying plunger well cycles to match key reservoir performance indices. Natural Gas STAR partners have reported annual gas savings averaging 600 thousand cubic feet ("Mcf") per well and increased gas production of up to 18,250 Mcf per well, worth an estimated $127,750 through the implementation of plunger lifts. Installing smart well automation on plunger lift systems typically results in an average savings of 500,000 cubic feet of methane per well, per year.[128]

7. Installation of BASO Valves on All Gas-fired Heaters

Crude oil heater-treaters, gas dehydrators and gas heaters located at exploration and development sites have pilot flames which can be extinguished by strong winds, causing the venting of natural gas. BASO valves automatically shut off the flow of natural gas upon the extinguishment of the pilot flame, thereby preventing unnecessary pollutant and methane losses. BASO valves are operated by a thermocouple that senses the pilot flame temperature and do not require electricity or manual operation. They are therefore ideal for remote locations. Capital costs are negligible, with each valve costing less than $100, and savings can be as great as 203 Mcf year for a 1,000 barrel per day heater-treater that experiences a flameout period of 10 days annually. Payback depends on how often the pilot flames go out and for what length of time. Typically payback occurs in less than 1 year.[129] A clean air standard based on the installation of BASO valves could result in significant product savings and emission reductions.

[127] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Installing Plunger Lift Systems in Gas Wells", *available* at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.
[128] U.S. EPA, "Opportunities for Methane Reductions from Natural Gas Production", *available* at http://www.epa.gov/gasstar/documents/gremillion.pdf
[129] U.S. EPA, Install BASO Valves, *available* at http://www.epa.gov/gasstar/documents/installbaso.pdf; *See also* Draft Oil and Gas Ozone Reduction Strategy – Presented at February 26, 2008 Colorado RAQC Meeting.

8. Leak Detection and Repair at Compressor Stations in the Transmission and Storage Sectors.

Compressor stations occur throughout the natural gas transmission and storage sectors and act to compress the gas to varying pressure points to overcome pressure losses that occur along a long-distance pipeline. According to EPA, compressor stations in the transmission sector alone account for approximately 50.7 Bcf of methane emissions annually.[130] A leak detection and repair program, similar to that already required for equipment and compressors located at natural gas processing plants, *see* 40 C.F.R. Part 60, Subpart kkk, offers a cost-effective way to prevent and eliminate emissions from compressor stations. Baseline surveys done by EPA partners have revealed that the majority of leaks come from a small number of parts, mostly valves, and that once these parts are identified, cost-effective repairs can be streamlined to accomplish maximum emissions reductions and gas savings.

9. Replacing Compressor Rod Packing From Reciprocating Compressors.

Reciprocating compressors are one of the largest sources of methane emissions at natural gas compressor stations. Methane emissions are produced by leaks in the piston rod packing systems used in the compressors—especially from older systems. Replacing compressor rod systems reduces methane emissions, increases savings, and results in greater operational efficiencies and equipment life-spans. Average gas savings equal $6,055 a year and far exceed the $540 implementation cost and the payback is two months.[131] California has proposed installing compressor rod packing systems as one strategy for reducing emissions from the state's oil and natural gas transmission industry. This, along with other strategies such as

[130] U.S. EPA, Lessons Learned from Natural Gas STAR Program, "Directed Inspection and Maintenance at Compressor Stations", *available* at http://www.epa.gov/gasstar/documents/ll_dimcompstat.pdf.

[131] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", *available* at http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

improving operating practices when compressors are taken off-line and replacing old flanges and fittings along pipeline, are expected to yield 0.9 MMT CO2e annually and save the oil and gas industry $17 million in annualized net savings.[132]

10. Replacement of Wet Seals with Dry Seals on Wet Seal Centrifugal Compressors

Centrifugal compressors are widely used throughout the natural gas production and transmission sectors. Seals on rotating shafts are used to prevent natural gas losses from compressor casing. Many of these seals use high-pressure oil as a barrier against escaping gas. These types of seals, referred to as "wet" seals, produce methane emissions when the circulating oil is stripped of the gas it absorbs. Dry seals use natural gas instead of oil to prevent gas losses. They also have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance. A dry seal can save about $315,000 per year and pay for itself in as little as 11 months. One Natural Gas STAR partner who installed a dry seal on an existing compressor reduced emissions by 97 percent, from 75 to 2 Mcf per day, saving almost $187,000 per year in gas alone.[133]

III. EPA ADOPTION OF RIGOROUS, WELL-DESIGNED EMISSION STANDARDS FOR THE SUITE OF AIR POLLUTANTS DISCHARGED BY THE OIL AND GAS SECTOR WILL ACHIEVE VITAL PUBLIC HEALTH AND ENVIRONMENTAL PROTECTIONS.

Section 111 of the Clean Air Act requires EPA to establish technology-based standards that limit the emissions of air pollutants from categories of stationary sources that "cause[s], or contribute[s] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[134] From "time to time" EPA must revise this list.[135] Once EPA

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[132] California's Climate Change Scoping Plan, V. 1 of Appendices, *supra* note 126, at 131.
[133] U.S. EPA, Lessons Learned from Natural Gas STAR Partners, "Replacing Wet Seals with Dry Seals in Centrifugal Compressors", available at http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.
[134] 42 U.S.C. § 7411(b)(1)(A).
[135] *Id.*

publishes a category of stationary sources, it must establish new source performance standards for air pollutants emitted from new and modified sources within the category (NSPS).[136] New source performance standards must reflect "best demonstrated technology" which is "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[137]

EPA listed the Crude Oil and Natural Gas Production on its "priority" list of categories that "cause[s], or contribute[s] significantly to, air pollution" which endangers human health and welfare in 1979.[138] Accordingly, EPA is obligated to promulgate new source performance standards for sources within this category. As demonstrated above, this source category consists of a wide range of equipment such as pneumatic devices, dehydrators, tanks, separation units, flanges, valves and other fittings, compressors, pumps, and heater-treaters located at and in-between wells, compressor stations and gas processing plants. In addition, these sources emit a range of pollutants including VOCs, methane, NOx, and sulfur dioxide ("SO_2"). Despite the large number of sources within the source category, and the myriad pollutants they emit, to date EPA has issued only two performance standards for this category. Specifically, to limit VOCs, EPA has established a VOC leak detection standard for certain equipment located at onshore gas processing plants (e.g., compressors, other than reciprocating compressors in wet gas service, glycol dehydrators, pumps, valves and flanges) and a standard that limits SO_2 emissions from

[136] 42 U.S.C. § 7411(a)(1).
[137] 42 U.S.C. § 7411(a)(1).
[138] 42 U.S.C. § 7411(b)(1)(A); 44 Fed. Reg. 49222 (August 21, 1979) (codified at 40 C.F.R. § 60.16).

sweetening units and sulfur recovery units also located at natural gas processing plants.[139] These standards fall woefully short of providing adequate protection to human health and the environment as they apply to only a fraction of the sources located within the Crude Oil and Natural Gas Production source category and only to two of the many types of air pollutants emitted by sources within the category.[140]

Existing sources account for a significant percentage of emissions from oil and gas sources. To date, EPA has not issued any emission guidelines to reduce air pollution from existing sources.[141] The Clean Air Act calls for EPA to issue emission guidelines applicable to existing sources once it establishes new source performance standards for a category of new sources:

> Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant form designated facilities… and upon or after promulgation of standards of performance for control of a designated pollutant from affected facilities, a final guideline document will be published and notice of its availability will be published in the FEDERAL REGISTER. (*emphasis added*).

40 C.F.R. § 60.22(a).[142] Emission guidelines must reflect "the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated."[143] As demonstrated above a number of western states require air pollution reductions from existing sources. Accordingly, in tandem with the revision of the current NSPSs

[139] "Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants", 50 Fed. Reg. 26122 (June 24, 1985); Onshore Natural Gas Processing SO2 Emissions, 50 Fed. Reg. 40158 (October 1, 1985).
[140] EPA has also issued standards to reduce NOx from new gas powered engines including spark ignition internal combustion engines and reciprocating internal combustion engines. *See* standards listed at *supra* note 7.
[141] *See* 40 C.F.R. 60.30, Subpart C.
[142] *See also* 42 U.S.C. §7411(d) (requiring the Administrator to "establish a procedure…under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source…".
[143] 40 C.F.R. § 60.22(b)(5).

and promulgation of additional NSPSs, EPA must promulgate standards for the control of air pollution from existing sources.

In addition to its duty to control air pollution from new and modified stationary sources under section 111, EPA must also issue standards to reduce HAPs from new and existing stationary sources.[144] Like section 111, section 112(c)(1) of the Clean Air Act requires EPA to publish a list of categories and subcategories of major and area sources of HAPs.[145] EPA must "from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information" its list of categories.[146] It may also add additional categories or subcategories at any time.[147] Once EPA lists a category of sources of HAPs it must establish emission standards that require the "maximum degree of reduction in emissions" of HAPs from new and existing sources.[148]

EPA included the "Oil and Natural Gas Production" category in its initial list of major source categories of HAPs in 1992.[149] EPA subsequently listed oil and natural gas production for regulation as part of its Urban Air Toxics Strategy in 1999 because TEG glycol dehydration units at oil and gas production facilities contributed nearly 50% of the national benzene emissions from area sources.[150] In 1998 EPA added the Natural Gas Transmission and Storage category to its list of major source categories of HAPs based on its finding that "natural gas transmission and storage facilities have the potential to be major HAP sources...[and] that there are major source TEG dehydration units in the natural gas transmission and storage source

[144] *See* 42 U.S.C. § 7412.
[145] 42 U.S.C. § 7412(c)(1).
[146] *Id.*
[147] 42 U.S.C. § 7412(c)(5).
[148] 42 U.S.C. § 7412(c)(2),(d).
[149] 57 Fed. Reg. 31576 (July 16, 1992).
[150] 64 Fed. Reg. 38706 (July 19, 1999).

category.[151] These listings triggered the requirement for EPA to promulgate emission standards for major and area sources within the Oil and Natural Gas Production category and for major sources within the Natural Gas Transmission and Storage category.[152]

Like the current NSPSs, the existing NESHAPs control HAPs from a limited number of oil and gas sources. Specifically, the NESHAPs apply to three types of equipment used during the production, processing and transmission of oil and gas: 1) glycol dehydrators; 2) storage vessels with the potential for flash emissions (i.e. condensate and oil tanks); and 3) certain equipment located at gas processing plants. Like the NSPSs, the NESHAPs fail to protect human health and the environment adequately by limiting emissions only from large glycol dehydrators, storage vessels and gas processing plants located at major sources.[153] According to EPA, this leaves a large number of dehydrators, storage vessels and equipment at gas processing plants unregulated: specifically the rule only applies to 440 out of 100,00 to 250,000 production facilities and 7 out of 2,000 transmission and storage facilities.[154] Moreover, the rules do not limit emissions from other sources such as wells, pneumatic devices, compressor seals, valves, or flanges or other production equipment located at oil and gas production facilities or natural gas storage and transmission facilities.

In 2007 EPA issued standards to limit emissions of HAPs from process vents on glycol dehydration units located at area sources within the Oil and Natural Gas Production category.[155]

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[151] 63 Fed. Reg. 6288, 6290 (Feb. 6, 1998).
[152] 42 U.S.C. § 7412(c)(2); 42 U.S.C. § 7412(k)(3)(B) (source categories identified as part of the Urban Air Toxics Strategy "are or will be listed pursuant to subsection (c) of section 112").
[153] The rule exempts dehydrators with an annual average natural gas flowrate less than 85 thousand m3/day or benzene emissions less than 0.90 Mg/yr. Similarly, only storage vessels that contain a hydrocarbon liquid with a storage tank gas to oil ratio equal to or greater than .31 m3/liter, an API gravity equal to or greater than 40 degrees, and an actual average throughput of hydrocarbon liquids equal to or greater than 79,500 liter/day are covered. Tanks located at facilities that exclusively process, handle or store black oil are also excluded.
[154] "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage", 64 Fed. Reg. 32610 (June 17, 1999).
[155] 72 Fed. Reg. 26 (Jan. 3, 2007).

Pursuant to the 2007 standard units located near urban areas must comply with the same standard that applies to units located at major sources, i.e. connect, through a closed-vent system, each process vent on the glycol dehydration unit to an air emission control system which must reduce HAP emissions by 95 percent or more. Units in rural areas need only comply with management practices to reduce glycol circulation rates. While the area source standards for glycol dehydrators located at oil and natural gas facilities expanded the scope of NESHAPs to apply to some smaller sources of HAPs, it still leaves many area sources of HAPs unregulated (e.g. well completions, re-completions, unloading, pneumatic devices and sources of fugitive emissions such as compressor seals and rod packing in the production and transmission and storage categories).

Rigorous, well-designed clean air standards will protect human health and the environment by addressing the suite of air pollutants emitted from the new, modified and existing sources of air pollution located at oil and natural gas exploration and production, processing, transmission and distribution facilities. Such standards should encompass the emissions reductions achievable through the implementation of the following cost-effective technologies:

- low or no-bleed pneumatic devices;
- green or reduced emissions completions and recompletions;
- still vent condensers and glycol flash separators or other technologies that reduce vented emissions from glycol dehydrators by 98% or better;
- vapor recovery units or other equipment that reduces emissions from crude oil, condensate and produced water tanks by 98% or better;
- leak detection and repair for production fugitives;

- plunger lifts and "smart" well automation systems for well unloading;
- BASO valves on heater-treaters, gas dehydrators and gas heaters;
- leak detection and repair at compressor stations;
- replacement of compressor rod packing;
- dry seals for centrifugal compressors;

IV. CONCLUSION

For the foregoing reasons, we respectfully request EPA protect human health and the environment by adopting clean air measures to reduce emissions of methane, air toxics and other hydrocarbon emissions from the full range of oil and gas activities.

Appendix A: Emissions Estimates and Projections: **Key oil and gas producing basins in the Intermountain West and Gulf region.**

Table 1: 2006 VOC and NOx emissions and projected 2010/2012 emissions (Tons per Year)

Oil & gas emissions source	Haynesville shale*		Denver-Julesburg basin		Uinta basin		Piceance basin		North San Juan basin**		South San Juan basin		Wind River basin	
	2012 mod.	2012 agg.	2006	2010	2006	2012	2006	2012	2006	2012	2006	2012	2006	2012
VOC														
Condensate tanks	N/A	N/A	53,510	53,109	6,195	21,719	3,405	1,895	0	0	3,964	3,790	710	519
Oil tanks	N/A	N/A	0	0	14,357	20,722	0	0	165	165	2,430	2,359	449	486
Dehydrators	33	88	506	332	19,470	30,665	2,929	2,371	14	10	11,372	10,896	1,324	1,010
Well completions	664	850	1,174	1,428	278	383	12,279	5,457	0	0	14,492	9,462	0	0
Well blowdowns	22	26	1,744	2,207	292	460	2,172	2,444	0	0	13,145	12,595	2,018	1,861
Fugitives	26	29	8,024	10,498	1,910	3,212	1,330	1,871	0	0	4,137	4,631	296	415
Pneumatic devices & pumps	460	533	12,381	16,342	23,301	39,404	2,532	3,835	0	0	1,726	1,925	6,351	7,303
NOx														
Compressor engines	N/A	N/A	11,506	12,625	2,207	3,169	5,705	6,497	4,947	3,362	35,545	36,659	1,290	1,109
Drill rigs	20,236	25,962	5,152	6,267	4,779	4,773	5,382	1,668	225	249	848	386	218	284

*Haynesville shale emission estimates for 2012 under moderate and aggressive development scenarios. The moderate scenario assumes the presence of 37 drill rigs each drilling 5.8 wells a year with a success rate of 55%. The aggressive scenario assumes the presence of 170 drill rigs. Haynesville emissions are scaled from estimated tons per day to annual emissions by multiplying by 365.

**VOC emission estimates in the Haynesville Shale and N. San Juan basin are substantially smaller than for other areas inventoried because of the nature of the respective resources. The Haynesville formation primarily produces dry natural gas, with no significant quantities of condensate. Therefore, VOC emissions are low and there are no emissions associated with condensate tanks or oil tanks. Similarly, the predominant resource in the N. San Juan is coal-bed methane which also has a low VOC content.

Table 2: 2006 Oil and Gas Production Data for Six Intermountain West Basins and NOx and VOC Emissions (TPY)

Basin	Spud count	Well count	Oil production (bbl)	Gas production (mcf)	NOx emissions (tpy)	VOC emissions (tpy)
Denver-Julesburg	1,500	16,774	14,242,088	234,630,779	20,783	81,758
Uinta	1,069	6,881	11,528,121	331,844,336	13,093	71,546
Piceance	1,186	6,315	7,158,305	421,358,666	12,390	27,464
North San Juan	127	2,676	32,529	443,828,500	5,700	2,147
South San Juan	919	20,649	2,636,811	1,020,014,851	42,075	60,697
Wind River	98	1,350	3,043,459	198,190,024	1,814	11,981

Appendix B: Comparison of oil and gas air regulations federal, Wyoming, Colorado, Montana, Utah, and California.

Source	EPA	WY	CO	Other	Emission Reduction Technology/Action
Pneumatic devices	No	Broad Coverage. Operators must use low or no-bleed devices or route discharge streams to closed loop systems.	Broad Coverage. New and existing controllers in ozone nonattainment (NA) and nonattainment/maintenance areas (NA/M) must be low-bleed. Statewide, new, replaced or repaired devices must be low or no-bleed.	Proposal. CA has proposed requirements substituting high-bleed with low-bleed devices.	Replace high bleed devices with low or no-bleed devices. Route discharge streams to closed loop systems.
Well venting during completions and re-completions	No	Broad Coverage. Must use green completions in JPAD Areas and CDAs.[1]	Broad Coverage. Must use green completions where technically and economically feasible.	MT requires control of VOC vapors greater than 200 British thermal units per cubic foot emitted from oil and gas wellhead equipment to be routed to a gas pipeline or smokeless combustion device equipped with an electronic ignition device or continuous pilot system.	Green completions.
Glycol dehydrators	Limited Coverage. Large dehydrators located at major	Broad Coverage. All new and existing dehydrators	Broad Coverage. Dehydrators located at all O&G E&P sites, natural gas compressor stations, drip stations, or gas processing plants with	No	Install still vent condensers, glycol flash separators or utilize combustion device capable of 98% destruction efficiency.

[1] JPAD refers to the Jonah and Pinedale Anticline Development Area. CDA refers to other Concentrated Development Areas.

	sources in the production, and and transmission categories must install MACT. Large glycol dehydrators located area sources in the production category near urban areas must install MACT. All other large dehydrators must comply with GACT.	in JPAD regardless of total potential or actual emissions must control HAPs and VOCs by 98%. All new and existing dehydrators in CDAs and statewide must control HAPs and VOCs by 98% upon first date of production (FDOP). Controls may be removed after one year if emissions <6 tpy and units are equipped with still vent condensers .[2]	actual VOC emissions ≥15 tpy must be controlled by 90% . Dehydrators with PTE 5 tpy VOCs located within ¼ mile of public place in Garfield, Mesa and Rio Blanco counties must control emissions by 90% .		
Condensate tanks	Limited Coverage. Large condensate tanks with the potential for flash emissions located at major sources in the	Broad coverage. [3] CDAs and JPAD: New and modified facilities must control VOC flash emissions by 98% upon FDOP. May remove	Broad Coverage. All tanks with PTE 5 tpy VOCs located within ¼ mile of public place in Garfield, Mesa and Rio Blanco counties must control VOC emissions with a device capable of achieving 95% control efficiency. Tanks under common	Limited Coverage MT requires control of VOC vapors greater than 200 British thermal units per cubic foot emitted from tanks with	Install vapor recovery systems, route emissions to control or capture device such as pipeline or flare.

[2] Alternatively, upon FDOP units must be equipped with reboiler still vent condensers and glycol flash separators. If, after 30 days, potential VOCs > 8 tpy, units must install combustion control capable of reducing emissions by 98%. After one year, combustion unit may be removed if total potential VOC emissions < 8 tpy.
[3] In Wyoming, the requirements listed for condensate tanks also apply to separation vessels (e.g.: gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots).

	production category Does not apply to facilities that exclusively handle, process or store black oil.	controls after one year if emissions < 8 tpy Statewide: New and modified facilities must control VOC flash emissions ≥10 tpy by 98% upon FDOP. May remove controls after one year if emissions < 8 tpy.	ownership or operation in NA, NA/M with cumulative emissions ≥30 tpy must meet declining percent reductions using device capable of achieving 95% control efficiency. All new or modified tanks in NA, NA/M with VOC emissions greater than 1 TPY must control emissions during the first 90 days with controls capable of achieving 95% control efficiency. Single tanks or tanks collocated together statewide that emit ≥ 20 tpy of VOCs must utilize controls capable of achieving 95% control efficiency.	PTE 15 tpy VOCs or more.	
Crude oil tanks	Limited Coverage. See condensate tanks.	Broad coverage. See condensate tanks.	Limited Coverage. For tanks in Piceance basin, see condensate tanks.	Limited Coverage. See condensate tanks.	Install vapor recovery systems or equipment capable of achieving 95% control efficiency.
Produced water tanks	No	Broad coverage. See condensate tanks.	Limited Coverage. For tanks in Piceance basin, see condensate tanks.	No	Install vapor recovery systems
Production/Processing fugitive emissions	Limited Coverage. VOC & HAP emissions from certain equipment at gas processing plants are subject to LDAR.	No	No	Proposal. CA has proposed improved LDAR, equipment replacement and upgrades.	LDAR and equipment replacement.

Compressors	Limited Coverage. Non-reciprocating compressors located at gas processing plants subject to LDAR and add-on controls to control HAPs and VOCs.	No	No	Proposal. CA has proposed requirements to replace rod packing systems and reduce emissions when compressors are taken off-line.	Replace rod-packing/ LDAR/reduce emissions when taken off-line
Pneumatic pumps	No	Broad Coverage. Upon FDOP must control all VOC and HAP emissions associated with discharge streams by 98% or route to closed loop system.	No	No	Replace gas-powered pumps with solar, electric, or air-driven pumps. Flare or route gas to closed loop system (i.e. sales line, collection line, fuel supply line)