WILDEARTH GUARDIANS' PROPOSED REDLINE MODIFICATIONS TO NMED'S PROPOSED 20.2.50 NMAC

TITLE 20 **ENVIRONMENTAL PROTECTION**
CHAPTER 2 **AIR QUALITY (STATEWIDE)**
PART 50 **OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS**

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20.2.50.7 **DEFINITIONS:** In addition to the terms defined in 20.2.2. NMAC – Definitions, as used in this Part, the following definitions apply.

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GG. **"Potential to emit (PTE)":** means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen. For wellhead sites, calculation of PTE shall include non-mobile source emissions that may occur prior to commencement of operation.

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20.2.50.112 **GENERAL PROVISIONS:**
A. **General requirements**

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(11) In permitting a stationary source subject to this Part pursuant to 20.2.72, 20.2.74, or 20.2.79 NMAC, the department shall deny any application for a permit or permit revision, including any general permit registration, where construction or modification will cause or contribute to air contaminant levels in excess of ninety-five percent of any primary National Ambient Air Quality Standard for ozone. Compliance with this Part does not demonstrate that a stationary source will not cause or contribute to exceedances of any National Ambient Air Quality Standard or New Mexico ambient air quality standard.

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D. **Reporting requirements:**
(1) The owner or operator shall submit records of all monitoring events documenting deviations of this Part to the department. For excess emissions, reports shall be submitted in accordance with 20.2.7 NMAC. For all other deviations, reports shall be submitted

semi-annually beginning January 1, 2022 and shall be submitted by the 30th day of the month following the end of each semi-annual period.

(2) Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

(3) The owner or operator shall comply with all applicable reporting requirements at 20.2.7 NMAC.

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Executive Summary

Jeremy Nichols is the Climate and Energy Program Director for WildEarth Guardians, a nonprofit environmental advocacy organization whose missions is to protect wildlife, wild places, wild rivers, and health in the American West. Jeremy has held this position since August 2008. Prior to holding this position, Mr. Nichols founded and directed the clean air advocacy organization, Rocky Mountain Clean Air Action.

In his capacity as Climate and Energy Program Director, Jeremy develops, directs, and leads the implementation of advocacy strategies to protect the climate through the advancement of clean energy, environmental and health safeguards, and policies that reduce greenhouse gas emissions. These efforts frequently entail engaging in air quality issues and advancing policies, actions, and accountability around clean air.

His experience with air quality regulation is extensive and diverse. For over 15 years, Mr. Nichols has been involved in the development of rules, permits, policies, and actions to address air quality concerns in the western United States, at both a federal and state level.

Experience

2008- Present:	**WildEarth Guardians, Climate and Energy Program Director**. Developing and leading initiatives to advance action to reduce greenhouse gas emissions and safeguard the climate in the western United States, including initiatives to confront air pollution, drive accountability for public health, and enforce the Clean Air Act. Working from the organization's Denver Office, have developed and managed coalitions and projects to address air quality issues affecting health, the environment, and climate in Colorado, Montana, New Mexico, Utah, Wyoming, and other western states. In collaboration with scientists, attorneys, policymakers, elected officials, and the general public, have helped secure greater accountability to climate and clean air in the American West.
2005-2008:	**Rocky Mountain Clean Air Action, Executive Director**. Founded and directed the nonprofit advocacy group in its efforts to address air quality issues in the western United States and ensure compliance with state and federal clean air laws across the region. Working from Denver, Colorado, engaged with constituents across the western United States to promote

greater public involvement in air quality proceedings and used the law, science, and policy to spur the development and implementation of stronger clean air safeguards in states including Colorado, New Mexico, and Wyoming.

2000-2005: **Biodiversity Conservation Alliance, Program Director.** Developed and led conservation program for local grassroots advocacy group located in Laramie, Wyoming. Conservation advocacy work included developing science-based petitions to protect endangered species, working with scientists to develop and advance forest management policies, gathering water quality data and driving action to protect clean water, and working with local attorneys and members of the public to ensure compliance with clean air and water laws at local facilities.

Education

1998-2004: **University of Wyoming**. Completed six years toward a B.S. in Geology, a minor in Chemistry, and additional classes toward a B.A. in Women's Studies. Enrolled in Honors Program.

Examples of Relevant Professional Engagement

2006

On behalf of Rocky Mountain Clean Air Action, engaged rulemaking hearing to update regulations for oil and gas industry emissions in the Denver Metro ozone nonattainment area and statewide in Colorado. Participation included draft and submitting prehearing filings and providing technical testimony during in-person hearing in December 2006.

2007

On behalf of Rocky Mountain Clean Air Action, provided technical testimony to the New Mexico Environmental Improvement Board for rulemaking to adopt mandatory greenhouse gas reporting rules. Testimony specifically addressed issue of oil and gas industry reporting of greenhouse gas emissions. Provided oral testimony to the Environmental Improvement Board during October 2-3, 2007 rulemaking hearing.

2008

On behalf of Rocky Mountain Clean Air Action, drafted and filed "Petition for Objection to Issuance of Operating Permit for Anadarko Petroleum Corporation's Frederick Compressor Station," https://www.epa.gov/sites/production/files/2015-08/documents/anadarko_petition2008.pdf.

On behalf of WildEarth Guardians, filed petition with U.S. Environmental Protection Agency to strengthen regulation of interstate transport of ozone and ozone forming emissions in western United States. Petition was filed in December 2008, http://wg.convio.net/support_docs/petition_final-EPA-ozone-transport.pdf.

2009

Drafted and filed notice of intent to file suit over Clean Air Act violations at coal-fired power plant owned by Xcel Energy north of Denver. Ultimately worked closely with attorneys for several years to advance case, which was ultimately settled, https://pdf.wildearthguardians.org/site/DocServer/WG_vs_XCEL_ENERGY_final_proposed_CD.pdf.

2010

On behalf of WildEarth Guardians, drafted and submitted "Petition for Objection to Issuance of Operating Permit for Public Service Company of New Mexico's San Juan Generating Station," https://www.epa.gov/sites/production/files/2015-08/documents/san_juan_petition2010.pdf

Together with partner organizations, drafted and submitted rulemaking petition to U.S. Environmental Protection Agency to list coal mines as a source category for purposes of regulation under Section 111 of the Clean Air Act, https://www.biologicaldiversity.org/programs/climate_law_institute/global_warming_litigation/clean_air_act/pdfs/Coal_Mine_Petition-06-15-2010.pdf.

2011

Drafted and submitted comments to the U.S. Environmental Protection Agency regarding the State of Nevada's regional haze state implementation plan, https://pdf.wildearthguardians.org/site/DocServer/2011-8-22_Nevada_Regional_Haze_Comments.pdf.

2012

Secured U.S. Environmental Protection Agency response to petition to object to Title V Operating permit issuance for EVRAZ Rocky Mountain Steel Mill in Pueblo, Colorado, https://www.epa.gov/sites/production/files/2015-08/documents/evraz_response2011.pdf.

2013

Working with attorneys, developed and drafted legal complaint over U.S. Environmental Protection Agency failure to take action on Title V Operating Permit application for Bonanza coal-fired power plant in Utah, https://pdf.wildearthguardians.org/site/DocServer/Final_Complaint_12-20-2013.pdf.

2014

Drafted and submitted petition to the U.S. Environmental Protection Agency to designate Uinta Basin of northeast Utah an ozone nonattainment area due to ongoing violations of ambient air quality standards, http://www.riversimulator.org/Resources/farcountry/Air/UIntaBasinOzoneNonattainmentPetitionJan2014.pdf.

2015

Drafted and filed Petition for Review with U.S. Environmental Appeals Board over U.S. Environmental Protection Agency approval of Title V Operating Permit for Bonanza power plant in Utah, https://yosemite.epa.gov/OA/EAB_WEB_Docket.nsf/Filings%20By%20Appeal%20Number/8E7A7CA8B99D57B085257DC700663152/$File/2015-1-7%20WG%20Deseret%20Petition%20for%20Review.pdf.

Drafted and filed notice of intent to file suit over U.S. Environmental Protection Agency failure to promulgate federal implementation plan to address regional haze in the State of Utah, https://www.epa.gov/sites/production/files/2015-05/documents/weg_noi_01212015.pdf.

2016

Working with WildEarth Guardians attorneys, helped negotiate agreement around the Craig coal-fired power plant located in northwest Colorado, https://wildearthguardians.org/press-releases/wildearth-guardians-reaches-western-colorado-clean-air-and-clean-energy-agreement/.

2017

Working with WildEarth Guardians attorneys, drafted notice of intent to file suit over Clean Air Act violations at Colorado Springs coal-fired power plant and legal complaint against Colorado Springs Utilities over violations, https://pdf.wildearthguardians.org/site/DocServer/Complaint_Doc_1__1_.pdf.

2018

Drafted and filed petition for review to U.S. Environmental Appeals Board over Environmental Protection Agency approval of six Title V Operating Permits in the Uinta Basin of northeast Utah, https://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Filings%20By%20Appeal%20Number/417F3A33696C3725852582C500422870/%24File/2018-7-7%20EAB%20Appeal%20of%20Anadarko%20SMNSR%20Permits.pdf.

2019

Drafted and submitted written testimony and provided expert oral testimony to the Colorado Air Quality Control Commission in December 2019 rulemaking hearing regarding revised regulations to reduce ozone forming emissions from the oil and gas sector in Colorado, https://drive.google.com/file/d/1HE6T0I8sLnkqPMZbZzneWQl90toyycus/view?usp=sharing.

2020

Drafted and submitted written testimony and provided expert oral testimony to the Colorado Air Quality Control Commission in September 2020 rulemaking hearing regarding revised regulations to further reduce ozone forming emissions from the oil and gas sector in Colorado and to enhance monitoring of pre-production operations associated with oil and gas well development, https://drive.google.com/file/d/1zLeIZ1DQ1UKgUk8kdKV9YiK-aJmMdF_v/view?usp=sharing.

Drafted and submitted written testimony and provided expert oral testimony to the Colorado Air Quality Control Commission in December 2020 rulemaking hearing regarding Colorado's revised state implementation plan for the Denver Metro serious ozone nonattainment area.

2021

Working closely with WildEarth Guardians' attorneys, helped draft legal complaint over the State of Colorado's failure to take action on Title V Operating Permit applications for Denver area oil refinery, https://pdf.wildearthguardians.org/support_docs/Guardians%20Suncor%20Title%20V%20Complaint%20-%20Adams%20County.pdf.

Drafted and submitted written testimony and provided expert oral testimony to the New Mexico Environmental Improvement Board in June 2021 rulemaking hearing regarding the state's certification of its "good neighbor" state implementation plan for the 2015 ozone national ambient air quality standards.

DIRECT TECHNICAL TESTIMONY OF JEREMY NICHOLS

I. Introduction

My name is Jeremy Nichols, and I am the Climate and Energy Program Director for WildEarth Guardians (Guardians). Guardians is a nonprofit environmental advocacy organization founded 32 years ago in Santa Fe, New Mexico. The organization's mission is to protect and restore the wildlife, wild places, wild rivers, and health of the American West. The organization currently has more than 120,000 members and supporters.

I present this written testimony on behalf of Guardians for the public hearing in the matter EIB 21-27, regarding the New Mexico Environment Department's (NMED) petition filed with the Environmental Improvement Board for the adoption of proposed new regulation 20.2.50 NMAC, which would limit ozone precursor emissions from the oil and gas industry.

My testimony supports WildEarth Guardians' position that additional language is needed in the proposed 20.2.50 NMAC to ensure proper emission regulation within the oil and gas sector, to ensure public transparency around compliance, and to ensure consistency with New Mexico statutes and current air quality policy implementation. This additional language would be minor, yet it would be hugely important for ensuring effective regulation, protection of public health and well-being, and for achieving environmental justice.

II. Qualifications

My full background and qualifications are set forth in my resume, which is identified as WildEarth Guardians Exhibit 2.

I am currently the Climate and Energy Program Director for WildEarth Guardians. In this capacity, I have led the organization's engagement in air quality regulatory matters for over 13 years. Previous to this position, I was the founder and director of a nonprofit clean air advocacy organization called Rocky Mountain Clean Air Action. I have over 20 years of direct, hands-on experience in weighing in on and scrutinizing air quality regulatory actions, including stationary source permitting, SIP revisions, state-only rulemakings, and enforcement. I work closely with and provide consulting support for scientists, attorneys, elected officials, and the general public on air quality and air quality regulatory matters.

In my years of working on air quality regulatory issues, I have provided testimony, comments, and information to numerous air quality agencies, boards, and commissions. I have provided technical testimony to the New Mexico Environmental Improvement Board. I have provided expert testimony to the Colorado Air Quality Control Commission. I have developed and submitted comments on numerous permits, both New Source Review and Title V Operating Permits, and state regulatory proposals. I have provided comments and testimony in response to numerous EPA regulatory actions, including SIP reviews, proposed New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, regional haze regulations, and nonattainment planning. I have practiced before the EPA's Environmental Appeals Board.

I have specific and longstanding experience regarding the development of air quality regulations for the oil and gas sector in Colorado, which has experienced high ozone pollution across the state due in large part to unchecked emissions from the oil and gas sector. I participated in the first-ever rulemaking to adopt statewide regulations to control volatile organic compound (VOC) and nitrogen oxide (NOx) emissions from oil and gas production equipment, including storage tanks, compressor engines, and glycol dehydrators. These rules were first adopted in 2006 and have since been updated regularly. I most recently participated in rulemaking proceedings before the Colorado Air Quality Control Commission in 2019 and 2020 regarding updates to oil and gas air quality regulations related to monitoring of air emissions during pre-production activities, control of emissions from flowback operations, control, regulation of VOCs from storage tanks and other equipment, and related to the permitting of oil and gas exploration and production facilities. Attached as Exhibit 4 is an example of recent written testimony that Guardians, along with other organizations, presented to the Colorado Air Quality Control Commission on issues related to the regulation of air pollution from the oil and gas sector.

III. The Need for Action

While the Board is legally obligated to adopt a plan, including rules, to limit emissions of ozone precursor emissions whenever ambient concentrations exceed 95% of the National Ambient Air Quality Standards (NAAQS), it's also simply good public health and environmental justice policy. It is well known that ground-level ozone, the key ingredient of smog, poses serious health and environmental risks. Although New Mexico has historically had the foresight to prevent ozone problems from occurring in the first place, unfortunately unchecked emissions primarily from the oil and gas sector have pushed concentrations of this poisonous gas above the NAAQS throughout the state. Communities in Bernalillo, Dona Aña, Eddy, Lea, Rio Arriba, San Juan Sandoval, and Valencia Counties have also suffered ozone concentrations at or above 95% of the NAAQS, contrary to state law and contrary to good public health policy.[1]

There is now an urgent need to clamp down on ozone forming emissions, bring all parts of New Mexico into compliance with state law, and ensure consistent and meaningful protection of people and clean air across the Land of Enchantment.

In this case, the Department has proposed regulations that would curtail VOC and NOx emissions—key ozone precursor pollutants—from the oil and gas sector, a major polluter in New Mexico. Not only is there a trove of evidence supporting the regulation of oil and gas industry emissions to address ozone problems, but for New Mexico, it is the most critical source to regulate given the industry's outsized impact on air quality in the San Juan and Permian oil and

[1] Although the Environmental Improvement Board does not have jurisdiction over air quality in Bernalillo County, the Board is required under the Clean Air Act to ensure that emissions subject to its jurisdiction outside Bernalillo County do not significantly contribute to nonattainment or interfere with maintenance in Bernalillo County.

gas producing basins, located in the northwestern and southeastern portions of the state, respectively.

A. Emissions from the Oil and Gas Sector are Contributing to High Ozone Levels Across the Western United States

To begin with, it is important to highlight the longstanding understanding that the oil and gas industry's ozone precursor emissions can have significant impacts on regional ozone formation and cause or contribute to exceedances and even violation of the NAAQS, particularly in the western United States. Studies and firsthand experience have confirmed the myriad sources of VOC and NOx emissions associated with oil and gas extraction can produce large amounts of ozone-forming pollution and contribute to exceedances and/or violations of the NAAQS.[2, 3]

In Colorado, the state first adopted regulations in 2004 to control oil and gas industry emissions to address ground-level ozone problems in the Denver Metro region.[4] Since then the state has updated its air quality regulations numerous times to further reduce oil and gas industry emissions to address the state's ongoing ozone problem.[5] While these regulatory efforts have been driven by the U.S. Environmental Protection Agency (EPA) strengthening the NAAQS in response to updated science, these efforts also reflect Colorado's challenge to fully and effectively regulate emissions from the oil and gas industry, which have grown tremendously in the state and presented new and more complex pollution control challenges.

Other notable examples of states recognizing the need to control emissions from the oil and gas industry to address ozone problems include Utah and Wyoming. In western Wyoming, unchecked oil and gas pollution has pushed ozone levels to violate the NAAQS in the Upper Green River Basin, an area of intensive oil and gas development and very few residents.[6] In 2018, the EPA designated northeastern Utah's Uinta Basin an ozone nonattainment area due to oil and gas industry emissions pushing ozone levels above the NAAQS.[7]

In response to the oil and gas industry's unchecked emissions, Colorado, Utah, and Wyoming have all adopted oil and gas industry-specific regulations to curtail emissions.[8]

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[2] *See e.g.* Exhibit 5, Pozzer, A., M.G. Schultz, D. Helmig, "Impact of U.S. Oil and Natural Gas Emission Increases on Surface Ozone is Most Pronounced in the Central United States," *Environ. Sci. Technol.* 2020, 54, 12423-12433.

[3] An exceedance of the NAAQS occurs whenever ozone concentrations rise above the level of the NAAQS. A violation of the ozone NAAQS whenever the three-year average of the annual fourth highest 8-hour reading exceeds the NAAQS. 40 C.F.R. § 50.19. While an exceedance is cause for health concern, a violation is cause for health alarm.

[4] Exhibit 6, Regional Air Quality Council, "Early Action Compact Ozone Action Plan, Proposed Revision to the State Implementation Plan, Draft" (Feb. 2004).

[5] *See e.g.* Exhibit 7, *Denver Post*, "Oil, gas industry may face tougher air quality rules" (April 2008); Exhibit 8, "Air Quality Control Commission adopts first phase of rules to reduce oil and gas emissions," Press Release (Dec. 2019).

[6] Exhibit 9, Thuermer, A.M., "DEQ confirms ozone pollution violated federal standards," *Wyofile* (June 18, 2019).

[7] Exhibit 10, U.S. EPA, "Final Area Designations for the 2015 Ozone National Ambient Air Quality Standards Technical Support Document."

[8] A copy of Colorado's regulations are attached as Exhibit 11. Utah's regulations are attached as Exhibit 12. Wyoming's regulations, which are attached as Exhibit 13, require best available control technology to limit VOC emissions, including from oil and gas operations.

State Oil and Gas Air Quality Regulations

State	Oil and Gas Air Quality Regulations
Colorado	Air Quality Control Commission Regulation Number 7
Utah	Utah Administrative Rules, R307-501—511
Wyoming	Wyoming Air Quality Standards and Regulations, Chapter 3, Section 6

B. New Mexico's Ozone Problem is Not Improving

While New Mexico regulators have long understood the link between oil and gas development and high ozone, the state unfortunately has not followed the lead of its neighbors. The result is that oil and gas producing areas are now among the most polluted in the state.[9]

Indeed, monitors in the Permian Basin are now showing that the region is in violation of the ozone NAAQS. Accordingly, in March of this year, WildEarth Guardians petitioned the EPA Administrator to designate the region a "nonattainment," or dirty air area.[10] The petition also called on the EPA to find that New Mexico's State Implementation Plan (SIP) is inadequate to attain and maintain the NAAQS in light of ozone violations.

So far in 2021, the situation appears more dire than ever. According to the EPA's AirData website, 77 exceedances of the ozone NAAQS have been recorded at monitoring sites in New Mexico.[11] Ozone concentrations in excess of 95% of the current NAAQS of 0.070 parts per million have been recorded 149 times throughout the state, including in Bernalillo, Dona Aña, Eddy, Lea, Rio Arriba, San Juan, Sandoval, Santa Fe, and Valencia Counties.

Included as WildEarth Guardians Exhibit 16 is a spreadsheet I prepared, based on air quality data reported by EPA at its AirData webpage, listing instances during which ozone concentrations in excess of 95% of the NAAQS have been recorded so far in 2021 at New Mexico monitoring sites. This exceedance data is sorted from highest 8-hour exceedance (0.089 parts per million, recorded in Dona Aña County on July 9, 2021) to the lowest (0.067 parts per million recorded at numerous monitoring sites in May, June, and July 2021) and it illustrates the severity of New Mexico's ozone problem and the likely consequences of inaction to curtail emissions. Of note:

- The data shows that 34 ozone exceedances of the NAAQS have been recorded so far in New Mexico's oil and gas producing counties, including Eddy, Lea, Rio Arriba, San Juan, and Sandoval. In the attached spreadsheet, I highlight data recorded from monitors in these counties.
- There have been 70 instances during which ozone concentrations have been higher than 95% of the NAAQS, particularly at monitors in the San Juan and Permian Basins.

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[9] Exhibit 14, Hedden, A., "New Mexico's oil and gas counties among the most air-polluted in the state amid recent boom," *Carlsbad Current-Argus* (April 22, 2021).
[10] This petition is attached as Exhibit 15.
[11] Air quality data can be queried at AirData here, https://www.epa.gov/outdoor-air-quality-data/download-daily-data.

- Of New Mexico's oil and gas producing counties, Lea County has recorded the highest ozone with the monitor in Hobbs recording 0.086 parts per million on July 24, 2021.
- The monitor in Carlsbad in Eddy County has recorded more instances of ozone concentrations higher than 95% of the NAAQS than any other monitoring site in the state.
- This ozone has directly impacted communities across New Mexico, including Carlsbad, Hobbs, Farmington, Bernalillo, Las Cruces, and many others.
- Ozone exceedances have been recorded in Chaco Culture National Historical Park in San Juan County and within Carlsbad Caverns National Park in Eddy County.

While data reported to EPA's AirData database is not final, it illustrates the stark reality that ozone pollution in New Mexico is not subsiding and that without action to reduce ozone precursor emissions, people and communities are likely to continue to suffer.

This stark reality is underscored by the impacts of the climate crisis, which is raising mean surface temperatures, thereby extending the period when ground-level ozone is formed and creating conditions more conducive to the creation and persistence of ozone. One recent study predicted heightened levels of ground-level ozone created by climate change could cause a 7.3% increase in emergency room visits related to asthma by children aged 0–17.[12] A 2011 report by the Union of Concerned Scientists surveyed the literature concerning climate change and ground-level ozone and concluded that the "ozone penalty factor"—the amount ozone levels are projected to increase for every 1 degree Fahrenheit (ºF) increase in temperature—was 1.2 ppb.[13]

The daily temperature in New Mexico is already 2.7 ºF warmer today than it was in 1970, and estimates indicate the Southwest could warm from 4 ºF to 10 ºF by 2100.[14] Thus, based solely upon the "ozone penalty factor," global heating alone is likely to result in ground-level ozone levels in the state between 4.8 to 12 ppb higher. This increase is separate and apart from the significant increase in ozone pollution levels driven by local and regional emissions of ozone precursors. Absent action, climate change will continue to exacerbate the region's ozone levels, likely preventing parts of New Mexico from ever achieving compliance with the ozone NAAQS.

IV. A Good Start, But Improvements Needed in NMED's Proposed Rules

NMED's proposed regulations are a long-overdue, yet positive step in the right direction. Although it appears that compliance dates could be accelerated for many proposed control measures, in general, the proposed regulations will assure progress in curtailing ozone forming emissions from the oil and gas sector.

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[12] Exhibit 17, Perry E. Sheffield et al., *Modeling of Regional Climate Change Effects on Ground-Level Ozone and Childhood Asthma*, 41 AM. J. PREV. MED. 252 (2011).

[13] Exhibit 18, *Rising Temperatures, Worsening Ozone Pollution*, UNION OF CONCERNED SCIENTISTS (Aug. 2, 2011), https://www.ucsusa.org/sites/default/files/2019-09/climate-change-and-ozone-pollution.pdf.

[14] Exhibit 19, *Confronting Climate Change in New Mexico*, UNION OF CONCERNED SCIENTISTS (May 2, 2016), https://www.ucsusa.org/resources/confronting-climate-change-new-mexico; Exhibit 20, *Fourth National Climate Assessment, Chapter 25: Southwest*, U.S. Global Change Research Program (2018), https://nca2018.globalchange.gov/chapter/25/.

That said, small improvements to the proposed regulations are justified and that they promise to yield even more substantial benefits for clean air and communities in New Mexico. Below, I detail WildEarth Guardians' proposed redline modifications to the proposed regulations and rationale for calling upon the Board to adopt them as part of any final rulemaking.

A. Ensuring Transparency

It is very concerning that NMED's proposed regulations do not require any reporting of monitoring or compliance data that would be gathered by owners or operators under the proposed regulations. Although the proposed 20.22.50.112(D) is ostensibly entitled "Reporting requirements," this provision simply authorizes NMED to request and obtain information from owners or operators, but does not otherwise affirmatively require any reporting.

This is problematic from public transparency standpoint. Reporting of monitoring data to NMED is critical for ensuring the public has access to air quality information that is relevant to their health and the health of their communities. Once data is submitted to NMED, it becomes subject to public disclosure, enabling people to request and readily obtain and assess important data regarding sources of air pollution that may be of concern or interest. Absent any affirmative reporting requirements, the public will have no ability to access data gathered by owners or operators under the proposed regulations.

Ideally, the proposed regulations should require reporting of all monitoring data gathered pursuant to Part 50. However, I understand this may pose logistical and data management challenges for NMED. Accordingly, what I would propose is that the regulation be modified to require only reporting of deviations. This is consistent with reporting requirements under Title V of the Clean Air Act, which require "prompt reporting" of deviations from permit terms and conditions to regulatory authorities.[15]

Here, the primary concern is understanding whether and to what extent owners or operators are complying with the provisions of 20.22.50 NMAC. The public should have the ability to be informed of instances where owners or operators have not complied or are currently out of compliance. Public access to this data should not depend on whether or not the data is requested by NMED, as the proposed rule is currently drafted.

Presumably, owners or operators would be required to report excess emissions consistent with 20.2.7 NMAC. What I would propose is that deviations other than excess emissions be reported on a semi-annual basis to NMED. These deviations would primarily include deviations from monitoring and recordkeeping requirements. By reporting these deviations, the public would be able to access data from NMED and understand whether owners or operators are fully complying with the proposed regulations and ensuring full protection of clean air and public health.

Accordingly, I propose that 20.2.50.112(D) be modified to require semi-annual reporting of all monitoring events documenting deviations from any provision of 20.2.50 NMAC. The

[15] *See* 40 C.F.R. §§ 70.6(a)(3)(iii)(B) and 71.6(a)(3)(iii)(B).

proposed addition would require reporting to begin January 1, 2022 and for reports to be submitted by the 30th day of the month following each semi-annual period. Where a monitoring event does not document any deviation, an owner or operator would be under no obligation to report. In addition, I would propose adding a provision to make explicitly clear that owners or operators subject to the proposed 20.2.50 NMAC are subject to excess emissions reporting under 20.2.7 NMAC. Below are WildEarth Guardians' proposed redlines to 20.2.50.112(D):

20.2.50.112 GENERAL PROVISION:

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D. Reporting requirements:

(1) The owner or operator shall submit records of all monitoring events documenting deviations of this Part to the department. For excess emissions, reports shall be submitted in accordance with 20.2.7 NMAC. For all other deviations, reports shall be submitted semi-annually beginning January 1, 2022 and shall be submitted by the 30th day of the month following the end of each semi-annual period.

(2) Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

(3) The owner or operator shall comply with all applicable reporting requirements at 20.2.7 NMAC.

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B. Ensuring Full and Effective Oversight of Emissions

For the proposed rules to be effective, there must be clarity and consistency around how potential emissions are calculated and established. The applicability of much of the proposed 20.2.50 NMAC depends upon a facility's "potential to emit," which is currently defined in NMED's proposed rule as:

> [T]he maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable.

Proposed 20.2.50.7(GG) NMAC. If potential to emit is not calculated accurately, it could lead to noncompliance and subversion of the effectiveness of the propose regulation.

Unfortunately, there are signs that in the context of the oil and gas production sector in New Mexico, "potential to emit" may at times, not be fully and accurately calculated in practice. In particular, I am concerned that pre-production stationary source emissions at wellhead facilities, including, but not limited to, non-mobile source emissions related to drilling, hydraulic fracturing, and well completion, often may not be accounted for in the assessment of a facility's potential to emit.

This concern is bolstered by assessments that confirm owners or operators of oil and gas wellhead sites may be commencing construction of facilities prior to obtaining permits in accordance with 20.2.72 NMAC.

In 2020, WildEarth Guardians collaborated with the UCLA Institute of the Environment and Sustainability to assess whether and to what extent owners or operators may have begun construction of wellhead facilities in the San Juan Basin prior to being permitted to construct by NMED. The final report revealed that 35% or more of assessed wellhead facilities were constructed prior to being permitted by NMED.[16] The report also found a significant disconnect between oversight by NMED and oversight by the New Mexico Oil Conservation Division. The report found that this lapse in permitting oversight is likely putting the Greater Chaco region and Navajo residents of the area at great risk from unauthorized air emissions.

This report raises concerns that assessments of facility potential to emit may be overlooking emissions occurring prior to wellhead facilities beginning production of oil and gas. To the extent these emissions are non-mobile source, they are not exempt from permitting oversight or regulation by NMED. These emissions must be appropriately accounted for in analyzing a facility's potential to emit.

To ensure clarity and effectiveness in the proposed 20.2.50 NMAC, I would propose adding a sentence at the end of the current definition of "Potential to Emit" at 20.2.50.7(GG) to clarify that at wellhead sites, non-mobile source emissions occurring prior to the commencement of operation must be accounted for in assessing potential to emit. The definition of "commencement of operation" is found at proposed 20.2.50.7(G) and essentially refers to the time at which a well is officially put into production. I believe adding clarity that potential to emit calculations must also account for any applicable emission occurring before this time is important for ensuring proper implementation of 20.2.50 and overall effective regulation of emissions from the oil and gas sector. Below is WildEarth Guardians' proposed redline to 20.2.50.7(GG):

20.2.50.7 DEFINITIONS:

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GG. "Potential to emit (PTE)": means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material

[16] This final report is attached as Exhibit 21.

combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen. For wellhead sites, calculation of PTE shall include non-mobile source emissions that may occur prior to commencement of operation.

C. Ensuring Clean Air Progress is not Undermined

Although NMED's proposed regulation will help to curtail oil and gas sector emissions, it is critical to ensure this Board provide NMED with the authority to maintain progress in protecting clean air and avoid unintended outcomes that could undermine this progress.

It's especially concerning that even in the face of mounting ozone pollution problems, particularly in the San Juan and Permian Basins, NMED continues to approve numerous permits authorizing the construction of new or modified oil and gas facilities. While the Department has the authority under its current permitting regulations to deny permits that would cause or contribute to violations of the ozone NAAQS, the Department does not have the authority to deny permits that would cause or contribute to ozone concentrations within 95% of the NAAQS. In other words, even if ozone levels rise to above 95% of the NAAQS, NMED has no authority to slow or pause the pace of permitting, even if more permitting would make the problem worse.

It is essential for the Environmental Improvement Board to ensure NMED's permitting authorities are brought into alignment with New Mexico's statute and the need to proactively safeguard public health and clean air. Accordingly, it is critical that as new regulations are adopted to control emissions, that emissions reduction gains are not erased as new stationary sources are constructed or modified.

Consistent with NMED's current permitting regulations, I would propose that the Board adopt an additional provision in the proposed 20.2.50 NMAC to ensure the Department has authority to deny permits for new or modified stationary sources that would cause or contribute to ozone concentrations in excess of 95% of the NAAQS. I would propose adding this provision in the proposed General Provisions under 20.2.50.112(A) as paragraph 11. Below is WildEarth Guardians' proposed redline to 20.2.50.112(A):

20.2.50.112 GENERAL PROVISIONS:
A. General Requirements

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(11) In permitting a stationary source subject to this Part pursuant to 20.2.72, 20.2.74, or 20.2.79 NMAC, the department shall deny any application for a permit or permit revision, including any general permit registration, where construction or modification will cause or contribute to air contaminant levels in excess of ninety-five percent of any primary National Ambient Air Quality Standard for ozone. Compliance with this Part does not demonstrate that a source will not cause or contribute to exceedances of any National Ambient Air Quality Standard or New Mexico ambient air quality standard.

V. Conclusion

NMED's proposed 20.2.50 NMAC is a giant step forward for clean air in New Mexico. However, in the interest of ensuring a fully effective suite of safeguards, the proposal can and must be improved in key areas. The additional recommendations set forth above are both reasonable and necessary to assuring ozone pollution in the state is successfully confronted and reduced to protect people, communities, and future generations.

BEFORE THE AIR QUALITY CONTROL COMMISSION
STATE OF COLORADO

IN THE MATTER OF PROPOSED REVISIONS, REGULATIONS NUMBERS 3 AND 7

PREHEARING STATEMENT OF THE CLEAN AIR, CLIMATE, AND HEALTH COALITION

Pursuant to Air Quality Control Commission ("AQCC") procedural regulations, the Clean Air, Climate, and Health Coalition ("CACHC") hereby submits the following Prehearing Statement in the matter of proposed revisions to Air Quality Control Commission ("AQCC") Regulations Numbers 3 and 7.[1]

EXECUTIVE SUMMARY

CACHC supports many of the revisions to AQCC Regulations No. 3 and 7 proposed by the Air Pollution Control Division ("APCD"). However, the APCD's proposal can and must be strengthened both to ensure more effective and expeditious progress toward attaining the national ambient air quality standards ("NAAQS") for ground-level ozone and to fulfill the mandate of Senate Bill 19-181 ("SB181") that harmful emissions be minimized from the oil and gas sector to protect public health and the climate in Colorado. The APCD's proposal must be strengthened to ensure consistency with both the Clean Air Act and laws and regulations governing oil and gas operations in the State of Colorado. Additionally, the APCD proposal should address achieving progress toward House Bill 1261 ("HB1261"), which requires the AQCC to adopt rules that assure timely progress toward meeting aggressive statewide greenhouse gas reduction goals.

Accordingly, we urge the AQCC to closely scrutinize the APCD's proposed rules and strengthen them as part of this rulemaking process. Below in our Prehearing Statement, we detail key areas where we believe the AQCC could make small, yet significant, improvements to the APCD's proposal.

The AQCC has broad authority to adopt regulations that it believes are warranted, necessary, or otherwise appropriate in light of the rulemaking record. *See* AQCC Procedural Rules, Section V.F.10. The Colorado Air Quality Control Act makes clear that the AQCC must "foster the health, welfare, convenience, and comfort of the inhabitants of the state of Colorado and to facilitate the enjoyment and use of the scenic and natural resources of the state[.]" C.R.S. § 25-7-102. To that end, the AQCC must enact regulations to "achieve the maximum practical

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[1] The Clean Air, Climate, and Health Coalition includes the organizations WildEarth Guardians, Colorado Rising, 350 Colorado, Physicians for Social Responsibility—Colorado, Mothers Out Front—Colorado, The Lookout Alliance, Fort Collins Sustainability Group, and Larimer Alliance for Health, Safety and Environment.

degree of air purity in every portion of the state [and] attain and maintain the national ambient air quality standards[.]" *Id*.

Accordingly, the AQCC is not bound to adopt only proposed regulations presented by the APCD, but rather is bound to ensure that its rules fully safeguard clean air and attain the NAAQS. Given this, we urge the AQCC to adopt a stronger set of rules that fully comply with the Clean Air Act, SB 181 and HB1261, and that more effectively safeguard public health and air quality throughout the State of Colorado.

TIME NEEDED FOR TESTIMONY

CACHC estimates it will need 1.5 hours to present testimony, any potential cross-examination, and rebuttal.

STATEMENT OF FACTUAL AND LEGAL ISSUES WITH THE PROPOSED RULES

I. Introduction.

Colorado's health and air quality is at serious risk due to unchecked volatile organic compound ("VOC") and nitrogen oxide ("NOx") emissions from the oil and gas industry. As developed has ramped up considerably over the last several years, emissions have risen, fueling high ground-level ozone levels and increasingly threatening the health of Coloradans.

As a recent Colorado Department of Public Health and Environment-supported study has confirmed, significant public health risks exist for those who are within 2,000 feet of oil and gas development activities, particularly during flowback operations. *See* Exhibit 1, ICF, "Final Report: Human Health Risk Assessment for Oil and Gas Operations in Colorado" (Oct. 17, 2019). These risks exist due to emissions of VOCs. This study is the latest in a series of studies to confirm that acute and chronic health risks exist for those in proximity to oil and gas development operations in Colorado.

Worsening these risks, ground-level ozone levels continue to rise above the NAAQS in the Denver Metro/North Front Range ozone nonattainment area. According to the latest update by the Regional Air Quality Council, monitors throughout the nonattainment area continue to violate both the 2008 and the 2015 ozone NAAQS. As of September 30, 2019, eight monitoring sites registered violations of the 2015 NAAQS of 70 parts per billion and three monitoring site continued to register violations of the 2008 NAAQS of 75 parts per billion. *See* Exhibit 2, APCD Ozone Summary Table (Sept. 30, 2019).

2017-2019 Eight-Hour Ozone Design Values for Denver Metro/North Front Range Ozone Monitors.

Monitor	2017-2019 Design Value (in parts per billion)
Highland	**74**
Boulder Reservoir	**73**
Mines Peak	**71**
Chatfield State Park	**78**
Welch	**71**
Rocky Flats North	**76**
NREL	**76**
Fort Collins West	**75**

As a result of the region's failure to attain the 2008 ozone NAAQS, the U.S. Environmental Protection Agency to "bump up" the Denver Metro/North Front Range nonattainment area from a "moderate" to a "serious" nonattainment area. *See* 84 Fed. Reg. 41,674 (Aug. 15, 2019). While a reclassification to a serious nonattainment area will provide new and critical tools to the APCD to better control the region's air pollution, it also reflects that the oil and gas industry's emissions are not controlled at a level that is commensurate with confronting the region's public health crisis.

Worse, unless major VOC and NOx emission cuts are made very soon within the oil and gas sector, the Denver Metro/North Front Range nonattainment area's air quality only stands to significantly worsen. Based on current attainment deadlines imposed by the Clean Air Act and ongoing high ozone levels, it appears there is very little possibility the region will attain the 2015 NAAQS or the 2008 NAAQS by applicable deadlines.

To attain the 2008 NAAQS by July 2021, which is the next attainment date, will require maintaining eight-hour ozone concentrations at below 70 parts per billion over the next two years. To attain the 2015 ozone NAAQS by August 2021 will require maintaining eight-hour ozone concentrations at below 65 parts per billion for the next two years. Overall, in 2020 and beyond, eight-hour ozone concentrations must be consistently reduced to levels below 70 parts per billion at every monitor in the nonattainment area. To our knowledge, this has not been accomplished since the beginning of ozone monitoring in the Denver Metro/North Front Range region.

Denver Metro/North Front Range Ozone Nonattainment Classifications, Attainment Deadlines, and Likelihood of Attainment

Ozone NAAQS	Current Classification	Attainment Deadline	On Track to Attain?	Next Classification	Attainment Deadline	On Track to Attain?
2008	Moderate	July 20,2018	No	Serious	July 20, 2021	No
2015	Marginal	August 3, 2021	No	Moderate	August 3, 2024	??

Compounding the problem is that there is serious doubt over whether the APCD is relying on accurate emissions inventories to estimate oil and gas industry emissions and to model their impacts to air quality along the Front Range. A recent presentation by Detlev Helmig, an atmospheric scientist with the University of Colorado, indicates current inventories of oil and gas industry VOC emissions in the Denver Metro/North Front Range region are more than twice as low as actual emissions. In 2017, the Division reported total oil and gas industry VOC emissions of 56,200 tons per year, whereas scientific studies report the actual emissions were around 134,000 metric tons, or more than 147,000 tons. *See* Exhibit 3, Helmig, D., "Air Quality Impacts from Oil and Natural Gas Emissions in the Northern Colorado Front Range," presentation to the Regional Air Quality Council (May 3, 2019). Importantly, these studies found there is no support for any conclusion that oil and gas industry VOC or methane emissions have declined.

Coupled with the requirements of the Clean Air Act, SB181, and HB1261, it is clear that the AQCC must significantly strengthen air quality regulations for the oil and gas sector. To this end, we urge the AQCC to set a goal of minimizing emissions such that public health and the climate are fully protected.

II. Specific Provisions of the Proposed Rules That CACHC Supports

We support the APCD's overall proposal to strengthen air quality regulations related to the oil and gas sector. There is no question that emissions form the industry are significantly interfering with attainment of the ozone NAAQS in the Denver Metro/North Front Range ozone nonattainment area, as well as endangering public health and welfare throughout the State of Colorado. In most respects, the proposed rules are simply modernizing Colorado's system of regulating emissions from the oil and gas industry. Many rules currently on the books are outdated, do not address the current technological capabilities of the industry, and do not effectively respond to the air quality problems presented by the boom in horizontal drilling and hydraulic fracturing that has occurred over the past decade. The requirements of the Clean Air Act, coupled with the mandate of SB181, compel stronger, more robust, and effective regulation. We specifically support and urge the AQCC to adopt the following critical updates to regulations proposed by the APCD.

A. Eliminating the 90-day Loophole

The elimination of the 90-day loophole is a critical step toward ensuring Colorado's air quality regulations are consistent with the Clean Air Act and to ensure effective oversight and permitting of the oil and gas industry.

The Colorado SIP currently allows companies to forego submitting construction permit applications for oil and gas production facilities until no later than 90 days after first production. *See* AQCC Regulation No. 3, Part B, Section II.D.7.[2] There is no other industrial sector in the state that is allowed to delay submitting construction permit applications after constructing and beginning operation of a source of air pollution. What's more, these provisions were enacted many years ago when the air quality impacts of the oil and gas industry were far less intensive

[2] The exemption actually allows companies to delay submitting permitting applications until annual pollutant emission notices ("APENs") are required to be submitted. APENs for oil and gas production facilities must be submitted within 90 days after first production. *See* AQCC Regulation No. 3, Part A, Section II.D.1.lll. The APCD's proposed rule changes would not affect the timing of APEN submission.

and problematic. At the time, it was deemed that oil and gas production facilities had negligible emissions. We know now that this is not the case.

Importantly, the 90-day loophole is currently being misinterpreted and abused by the oil and gas industry. While the 90-day loophole applies in the context of general construction permitting requirements set forth under AQCC Regulation No. 3, Part B, it does not apply in the context of major source permitting requirements set forth under AQCC Regulation No. 3, Part D. The Colorado SIP is extremely clear that major sources must obtain permits prior to construction, stating "Any new major stationary source or major modification [] shall not begin actual construction in a nonattainment, attainment, or unclassifiable area unless a permit has been issued containing all applicable state and federal requirements." AQCC Regulation No. 3, Part D, Section I.A.1. Unfortunately, industry has interpreted the 90-day loophole to allow even major sources to delay submitting permit applications until after they have constructed and begun operation.

As we explained to the AQCC earlier this year, this misinterpretation and abuse of the 90-day loophole has allowed hundreds of oil and gas production facilities to evade major source permitting requirements and to release more air pollution than they would otherwise be allowed to emit.

This abuse and misinterpretation underscores that the 90-day loophole in the Colorado SIP is fundamentally contrary to the Clean Air Act. Although originally approved by the U.S. Environmental Protection Agency as part of the SIP, it is now clear that the 90-day loophole should never have been approved.

Under the Clean Air Act, a SIP revision shall not "interfere with any applicable requirements concerning attainment and reasonable further progress [] or any other applicable requirement of this chapter." 42 U.S.C. § 7410(l). Here, the 90-day loophole not only interferes with requirements concerning attainment, but also interferes with applicable preconstruction permitting requirements.

In allowing sources of air pollution to construct and begin operation prior to obtaining permits, the SIP explicitly allows sources of air pollution to operate (i.e., pollute) with no oversight of emissions. This means that in the context of oil and gas production facilities, there is no way to ensure emissions do not interfere with requirements concerning attainment or reasonable further progress.

Further, under the Clean Air Act, a SIP must include a permitting program regulating the modification and construction of stationary sources "to assure that national ambient air quality standards are achieved" and must include a major permitting program pursuant to parts C and D of the Clean Air Act. 42 U.S.C. § 7410(a)(2)(C). In allowing sources of air pollution to construct and begin operation prior to obtaining permits, the SIP explicitly fails to properly regulate the construction of stationary sources to assure achievement of the NAAQS. Further, if the 90-day loophole is interpreted in such a way as to allow major sources to avoid submitting permit applications prior to construction and operation, then the SIP plainly interferes with major source permitting requirements set forth under parts C and D of the Clean Air Act.

The oil and gas industry has taken the position that they are only able to accurately calculate emissions for permitting purposes after beginning production. However, this argument is simply not true. Companies are already submitting permit applications prior to beginning production using reliable and accurate emissions estimates. Crestone Peak, for example, submitted an application on April 2, 2019 for a production facility with a proposed startup date of December 1, 2019. *See* Exhibit 4, Crestone Peak Resources Operating, LLC, Facility Permit Application, Regnier Farms 19H-B268 (April 2, 2019). According to the company, the permit application was submitted "based on sampling conducted at a representative facility." This is one of many examples demonstrating that the oil and gas industry is more than capable of obtaining construction permits prior to constructing and operating sources of air pollution. The oil and gas industry must responsibly provide best estimates of emissions prior to constructing sources of air pollution, as is required by other emitting industries.

The elimination of the 90-day loophole doesn't just make good policy sense, it's legally compelled. We urge the AQCC to adopt the APCD's proposed elimination of AQCC Regulation No. 3, Part B, Section II.D.7. Although elimination of the loophole will not address past abuse of the 90-day loophole and any noncompliance with major source permitting requirements under the Colorado SIP, it will ensure that, moving forward, there is effective oversight and regulation of oil and gas production facility emissions to ensure protection of public health and attainment of the NAAQS.

B. Moving From Systemwide Tank Regulation to Tank-by-Tank Regulation in the Denver Metro/North Front Range Ozone Nonattainment Area

Under the APCD's proposed rules, the systemwide approach to regulating tank emissions in the Denver Metro/North Front Range ozone nonattainment area would be phased out by April 30, 2020. This is not only a good policy move, it is also compelled by the Clean Air Act as the current systemwide approach to regulating tank emissions, which has been incorporated into the SIP, does not assure effective regulation of emissions to assure achievement of the NAAQS.

The key concern with the systemwide approach to controlling tank emissions under AQCC Regulation No. 7 is that it fails to regulate specific sources of air pollution such that attainment of the NAAQS is assured in relation to the operation of every tank. Under the Clean Air Act, SIPs must include enforceable limitations "as may be necessary or appropriate to meet the applicable requirements of [the Clean Air Act]" and include a program for the enforcement of these limitations "to assure that national ambient air quality standards are achieved." 42 U.S.C. §§ 7410(a)(2)(A) and (a)(2)(C). With the systemwide approach, operators are free to pick and choose which tanks to control—or not control—even though operation of certain tanks may interfere with applicable requirements of the Clean Air Act or cause or contribute to exceedances of the NAAQS. The systemwide approach could allow the most polluting tanks to remain uncontrolled, potentially jeopardizing attainment of the ozone NAAQS in the Denver Metro/North Front Range nonattainment area or otherwise interfering with other Clean Air Act requirements. What's more, certain communities and residents are likely to be unduly impacted by air pollution. Fundamentally, the systemwide approach fails to assure compliance with applicable requirements of the Clean Air Act and to assure achievement of the NAAQS.

We support the APCD's move to a clearer, more consistent, and more specific approach to regulation of tank emissions. Not only does it assure compliance with the Clean Air Act, but it assures effective emission reductions from tanks.

C. Consistent Statewide Approach to Emission Regulation

We support the APCD's proposal to assure consistent emission reductions under AQCC Regulation No. 7, particularly from tanks, on a statewide basis. The need to assure consistent, statewide regulation is twofold:

First, there is a need to assure consistent safeguards for public health and air quality are in place across Colorado. Creating tiers of protection where certain parts of the state are held to weaker standards will only create further health risk for citizens within these areas. This is underscored by SB181, which applies statewide, clearly signaling the Legislature's intent that the AQCC's efforts to minimize emissions apply statewide.

There is no reason that Coloradans outside the Denver Metro/North Front Range ozone nonattainment area should be denied the same level of air quality protections being implemented within the nonattainment area. The AQCC must steer clear of endorsing approaches to air quality regulation that apply unequally and stand to leave Coloradans more vulnerable than necessary.

Second, there is a need to remain vigilant and proactive in safeguarding clean air across Colorado. As the AQCC knows, ozone levels outside the Denver Metro/North Front Range nonattainment area regularly exceed the NAAQS, particularly in areas of western Colorado impacted by oil and gas development. While current 8-hour ozone design values (i.e., three-year average of annual fourth maximum 8-hour concentration) still measure below the current NAAQS, theyare increasingly approaching nonattainment levels. In fact, six monitors in western Colorado have design values within 90% of the NAAQS and two within 95%. *See* Exhibit 2.

2017-2019 Eight-hour Ozone Design Values for Western Colorado Ozone Monitors.

Monitoring Site	2017-2019 Design Value (ppb)	% of 2015 NAAQS (70 ppb)
Rifle	59	84%
Palisade	65	93%
Cortez	62	89%
Gothic	67	96%
Ignacio	66	94%
Bondad	66	94%
Mesa Verde NP	67	96%
Rangely	65	93%

It's critical to highlight that the State of New Mexico requires new air quality regulations be adopted to curtail ozone-forming emissions whenever concentrations exceed 95% of the

NAAQS. See NMSA 1978 § 74-2-5.3.A.[3] It is informative that neighboring states are taking a proactive approach to curbing ozone forming emissions.

Enacting regulations should be inherently proactive. Air quality regulation and protection of public health, particularly within the oil and gas sector, should not come only when there is a crisis. The AQCC should be forward-looking and ensure consistent safeguards are in place to prevent exceedances of the ozone NAAQS and overall protect public health across Colorado, consistent with its legislative mandate to ensure "the maximum practical degree of air purity in every portion of the state." C.R.S. § 25-7-102

D. Oil and Gas Operations Emissions Inventory

We support the APCD's oil and gas industry emission inventory requirements proposed under AQCC Regulation No. 7, Part D, Section V. These inventory requirements will ensure the APCD and the AQCC have access to complete information necessary to inform future regulation and oversight of the oil and gas sector. While we are concerned the APCD may lack the resources and expertise to assure effective quality oversight of data reported by the oil and gas industry, we believe the proposed regulations set the stage for the agency to ultimately achieve a high level of oversight that assures the most accurate emissions data is submitted.

Although we support the proposed emission inventory requirements, we urge the APCD and the AQCC to ensure that reported emissions data are made readily available to the public. To this end, we strongly support APCD's commitment to make this data available online in an understandable and accessible format. Keeping the public informed of oil and gas industry emissions is critical for fostering broader understanding and awareness of the issues and for encouraging more informed public engagement.

III. Provisions of the Proposed Rules That the AQCC Must Strengthen

The draft rule language proposed by the Division represents an important step toward controlling oil and gas industry air pollution and assuring protection of health in Colorado. That said, the proposed rules can and must be improved and strengthened in a number of regards. Overall, we urge the AQCC to improve the following proposed rules, move further to effectively minimize emissions consistent with SB181, and assure full compliance with the Clean Air Act. Below we detail our concerns and our recommendations for AQCC action.

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[3] The New Mexico statute specifically says:

> If the environmental improvement board or the local board determines that emissions from sources within its jurisdiction cause or contribute to ozone concentrations in excess of ninety-five percent of a national ambient air quality standard for ozone, it shall adopt a plan, including regulations, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and maintenance of the standard.

NMSA 1978 § 74-2-5.3.A.

A. Definition of "Commencement of Operation"

1. AQCC Regulation No. 3 Definition of "Commencement of Operation"

The current definition of "Commencement of Operation" is incorporated into the SIP and it governs the timing of preliminary permit analyses prepared by the APCD and other notifications. The current definition states, "A new source commences operation when it first conducts the activity that it was designed and permitted for (i.e., producing cement or generating electricity)." AQCC Regulation No. 3, Part A, Section I.B.12.

The APCD is proposing to add an entirely new section to the definition of "Commencement of Operation" that is specific to oil and gas well production facilities. As drafted, the proposed definition is vague and unenforceable, and it fails to meet the intent of the current definition of "Commencement of Operation." It also appears contrary to SB181's intent that the AQCC minimize emissions from pre-production activities. As SB181 makes clear, the AQCC now has explicit authority to regulate emissions "during pre-production activities, drilling, and completion." C.R.S. § 25-7-109(10)(c).

Under the APCD's proposal, commencement of operation would occur when "permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks from the first producing well[.]" Proposed AQCC Regulation No. 3, Part A, Section I.B.12. As written, the rule would allow sources to install less than complete permanent production equipment and claim that permanent production equipment is not in place and that commencement of operation had not occurred. The rule would also allow sources to inconsistently produce and claim that commencement of operation had not occurred.

We appreciate the APCD's intent to provide more specific direction related to when oil and gas production facilities commence operation. However, if a specific definition is to be provided for what "Commencement of Operation" means for the oil and gas industry, the AQCC should adhere to the intent of the current definition of "Commencement of Operation" under AQCC Regulation No. 3 and determine that commencement of operations at oil and gas well production facilities occurs when the facility first conducts the activity that it was designed and permitted for. This would mean that commencement of operation would occur when oil and/or gas is first extracted from a well.

***Recommended Action*:** The APCD's current proposal would add the following language to AQCC Regulation No. 3, Part A, Section I.B.12:

> For oil and gas well production facilities, commencement of operations is the date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks from the first producing well at the stationary source. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to commencement of operation. Commencement of operation is the date when production from the initial zones of the first producing well began consistently flowing to the permanent production equipment, even if more zones will be completed later.

We urge the AQCC to modify the language of the APCD's proposal as follows:

> For oil and gas well production facilities, commencement of operations is the date ~~permanent~~ production equipment is in place and product is ~~consistently~~ flowing to sales lines, gathering lines or storage tanks from ~~the first producing~~ any well at the stationary source. ~~Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to commencement of operation. Commencement of operation is the date when production from the initial zones of the first producing any well began consistently flowing to the permanent production equipment, even if more zones will be completed later~~.

2. AQCC Regulation No. 7 Definition of "Commencement of Operation"

We have similar concerns with the APCD's proposed definition of "Commencement of Operation" in AQCC Regulation No. 7. *See* Proposed AQCC Regulation No. 7, Part D, Section I.B.7 and Part D, Section II.A.6. The APCD is proposing to add this definition both as part of the SIP and as part of its suite of state-only oil and gas regulations.

Under the APCD's proposed revisions to Regulation No. 7, "Commencement of Operation" would govern when pollution controls must be installed to control emissions from storage tanks and other sources at oil and gas production facilities. For instance, under the proposed revisions, new tanks would have to comply with emission control requirements "by commencement of operation." Proposed AQCC Regulation No. 7, Part D, Section I.D.3.a. The APCD's proposed definition is nearly identical to the definition proposed under AQCC Regulation No. 3.

Under the APCD's proposal, commencement of operation would occur when "permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks form the first producing well[.]" Proposed AQCC Regulation No. 7, Part D, Section I.B.7. As written, the rule would allow sources to install less than complete permanent production equipment and claim that permanent production equipment is not in place and that commencement of operation had not occurred. The rule would also allow sources to inconsistently produce and claim that commencement of operation had not occurred. Overall, the language lacks clarity and enforceability.

With regards to the APCD's proposal to include the proposed definition into the SIP, this raises concerns that the definition, as proposed, is not enforceable under the Clean Air Act. Enforceability is a key element of SIPs. The Clean Air Act explicitly states that SIPs must contain, "***enforceable*** emissions limitations and other control measures." 42 U.S.C. § 7410(a)(2)(A) (emphasis added). In referring to section 110(a)(2), the EPA stated that "[m]easures are enforceable when they are duly adopted, and specify ***clear, unambiguous, and measurable requirements***." State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, 57 Fed. Reg. 13,568 (April 16, 1992) (emphasis added). Here, the use of the terms "permanent" and "consistently" are not clear or unambiguous.

Regardless, the point at which the oil and gas industry must be required to control emissions from storage tanks and other sources should be the point at which tanks or other sources are installed and begin releasing air pollution, regardless of whether there is "consistent" production. If the point is to minimize emissions consistent with SB181, then the Division must ensure that controls are installed, operating, and effectively controlling emissions as soon as tanks or other sources begin releasing pollution. Especially given that SB181 provides the AQCC authority to minimize pre-production emissions, there is no reason for delaying the installation and operation of pollution controls at oil and gas production facilities.

We support the APCD's conclusion that there is a need to develop a more refined threshold for determining when operators must be required to control emissions from tanks and other sources at oil and gas production facilities. We also support the APCD's finding that the definition of "Commencement of Operation" must be incorporated into the SIP. However, we again urge the AQCC to adhere to the intent of the current definition of "Commencement of Operation" found in Regulation No. 3 and determine that commencement of operations at oil and gas well production facilities occurs when the facility first conducts the activity that it was designed and permitted for. This would mean that commencement of operation would occur when oil and/or gas is first extracted from a well.

***Recommended Action*:** The APCD's current proposal would add the following language to AQCC Regulation No. 7, Part D, Section I.B.7 and Part D, Section II.A.6.:

> "Commencement of Operation" for oil and gas well production facilities is the date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks from the first producing well at the stationary source. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to commencement of operation. Commencement of operation is the date when production from the initial zones of the first producing well began consistently flowing to the permanent production equipment, even if more zones will be completed later.

We urge the AQCC to modify the language of the APCD's proposal as follows:

> "Commencement of Operation" for oil and gas well production facilities is the date ~~permanent~~ production equipment is in place and product is ~~consistently~~ flowing to sales lines, gathering lines or storage tanks from ~~the first producing~~ any well at the stationary source. ~~Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to commencement of operation. Commencement of operation is the date when production from the initial zones of the first producing any well began consistently flowing to the permanent production equipment, even if more zones will be completed later.~~

B. Inconsistent Storage Tank Emissions Regulation

We support the APCD's proposal to establish across-the-board control requirements for storage tanks. However, we are concerned the proposed control thresholds are arbitrarily inconsistent and will not serve to minimize emissions consistent with SB181.

As we understand the draft rule language, the APCD is proposing to revise the SIP and amend AQCC Regulation No. 7 to require controls for all storage tanks that have uncontrolled emissions of more than four tons/year of VOCs, and to establish a "state-only" rule that requires controls for all storage tanks that have uncontrolled emissions of two tons/year.

We oppose the APCD's attempt to establish two tiers of accountability around storage tank emissions. As we read the draft rule language, the four ton/year threshold for controls would become part of the Colorado SIP and therefore be federally enforceable (i.e., enforceable by the EPA and citizens). The two ton/year threshold would only be a part of state regulations and therefore not federally enforceable (i.e., only enforceable by the APCD).

The difference between federally enforceable and non-federally enforceable is not trivial. By incorporating standards into the SIP, the APCD empowers heightened oversight by enabling the EPA and citizens to play a role in scrutinizing and enforcing compliance. This gives a much-needed boost to the capacity of the APCD and also ensure a higher level of accountability.

To this end, we strongly urge the AQCC to establish an across-the-board SIP limit of two tons/year for tanks statewide. Given their impact to air quality and public health, and the need to minimize emissions under SB181, it is important and makes more sense to control emissions from all tanks that have uncontrolled VOC emissions of two tons/year. Clearly the two ton/year threshold is feasible and reasonable. And by incorporating it into the SIP, the AQCC ensures a high level of accountability and compliance, as well as effective minimization of emissions.

***Recommended Action*:** The APCD's current proposal would revise the Colorado SIP at AQCC Regulation No. 7, Part D, Section I.D.3 and Part D, Section I.D.3.c. as follows:

> Owners or operators of storage tanks with uncontrolled actual emissions of VOC equal to or greater than four (4) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves an average VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC.
>
> ….
>
> A storage tank not otherwise subject to Sections I.D.3.a. or I.D.3.b. that increases uncontrolled actual emissions to four (4) tons per year VOC or more on a rolling twelve month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month in which the storage tank VOC emissions exceeded four (4) tons per year on a rolling twelve-month basis.

We urge the AQCC to modify the language of the APCD's proposal as follows:

> Owners or operators of storage tanks with uncontrolled actual emissions of VOC equal to or greater than ~~four (4)~~ two (2) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves an average VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC.
>
> ….
>
> A storage tank not otherwise subject to Sections I.D.3.a. or I.D.3.b. that increases uncontrolled actual emissions to ~~four (4)~~ two (2) tons per year VOC or more on a rolling twelve month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month in which the storage tank VOC emissions exceeded ~~four (4)~~ two (2) tons per year on a rolling twelve-month basis.

We also urge the AQCC to consider striking all or portions of the APCD's proposal at AQCC Regulation No. 7, Part D, Section II.C.1.c. This section would establish the state-only two ton/year threshold for tanks. If the SIP is revised to establish a two ton/year threshold for tanks, then there would be no need for duplicative state-only regulation.

C. The Proposed Rules Should Explicitly Prohibit Flaring Unless Approved by the Colorado Oil and Gas Conservation Commission

We are concerned that the draft rules rely heavily on the use of flaring, or combustion, of gases to reduce emissions and in doing so may condone oil and gas production practices that are contrary to SB181 and existing oil and gas laws and regulations, and in contrast to the intent and requirements of HB1261.

Colorado law governing oil and gas development prohibits "waste" of oil and gas and to this end, Colorado Oil and Gas Conservation Commission ("COGCC") rules explicitly prohibit the "unnecessary or excessive" flaring of natural gas. COGCC Rule 912(a). In spite of this, the APCD's proposed revisions to AQCC Regulation No. 7 explicitly condone the use of flaring to reduce emissions. *See* AQCC Regulation No. 7, Part D, Section I.C.1.d.[4]

A combustion device is a flare in that its purpose is to burn off gases produced by oil and gas well facilities. Although these gases include VOCs, they also include natural gases, such as methane, that are subject to regulation by the COGCC. Indeed, the Colorado Oil and Gas Conservation Act defines "gas" broadly to mean "all natural gases and all hydrocarbons not defined in this section as oil." C.R.S. 34-60-103(5). Therefore, in allowing the use of combustion devices, or flares, to control emissions, the draft rule language is contrary to Colorado's prohibition on waste and COGCC regulations.

[4] Similar language is proposed under Part D, Section II.B.2.b.

The AQCC should modify any revision to Regulation 7 to provide that flaring, or the use of combustion devices, is prohibited except if that their operation is consistent with COGCC regulations. To this end, Regulation 7 should be modified to provide that the use of combustion devices can only be authorized by the Division if prior approval has been given by the COGCC and only under the timeframe approved by the COGCC. The AQCC should make these modifications in order to ensure the use of vapor recovery systems and to discourage oil and gas development that would otherwise rely on wasteful flaring to control VOC emissions.

Given SB181's mandate for the AQCC to ensure emissions from the oil and gas sector are minimized, Regulation No. 7 must be revised to disincentivize the use of flaring to reduce emissions and to require the capture and use of natural gas, rather than waste.

***Recommended Action*:** The APCD's current proposal expressly authorizes the use of flares, or combustion devices, to control emissions at AQCC Regulation No. 7, Part D, Section I.C.1.d. and Part D, Section II.B.2.b.

Proposed Section I.C.1.d states:

> If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly.

Proposed Section II.B.2.b states:

> If a combustion device is used to control emissions of VOCs and other hydrocarbons, it shall be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

We urge the AQCC to modify the language of the APCD's Proposed Section I.C.1.d as follows:

> If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly. The use of any combustion device to control emissions shall only be permitted upon prior approval by the Colorado Oil and Gas Conservation Commission in accordance with COGCC 900 Series rules, unless the owner or operator can demonstrate that the COGCC has determined the combustion device is not subject to COGCC 900 Series rules.

We further urge the AQCC to modify the language of the APCD's Proposed Section II.B.2.b as follows:

> If a combustion device is used to control emissions of VOCs and other hydrocarbons, it shall be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly. <u>The use of any combustion device to control emissions shall only be permitted upon prior approval by the Colorado Oil and Gas Conservation Commission in accordance with COGCC 900 Series rules, unless the owner or operator can demonstrate that the COGCC has determined the combustion device is not subject to COGCC 900 Series rules.</u>

D. The AQCC Must Consider Climate Impacts in Adopting New Rules

In addition to the passage of SB181, the Legislature this year also passed landmark climate legislation, HB1261 the Colorado Climate Action Plan, requiring the AQCC to adopt rules that assure timely progress toward meeting aggressive statewide greenhouse gas reduction goals. While SB181 should directly lead to further reductions in methane, which is a potent greenhouse gas, we also urge you to ensure that SB181 rules are developed with an eye toward further limiting overall greenhouse gas emissions from the oil and gas sector in order to make progress toward meeting HB1261's goal.

To this end, we strongly urge the AQCC to seize opportunities to advance climate progress as part of this rulemaking. Ensuring that emission controls are installed as early as possible, lowering the threshold for SIP-required tank emission controls, and limiting the use of flaring are all means of assuring greater greenhouse gas reductions as part of this rulemaking. We also urge the AQCC to consider other opportunities to further reduce greenhouse gas emissions, including a plan to phase out oil and gas permitting, in order to begin making progress toward meeting the goals of HB1261.

ISSUES TO BE RESOLVED BY THE COMMISSION DURING THE HEARING

1. Whether the proposed rules are consistent with the Clean Air Act, SB181, and HB1261?

2. Whether to modify the definition of "commencement of operation" in AQCC Regulations No. 3 and 7 to ensure oversight and emission controls are achieved as early as possible?

3. Whether the AQCC should revise the SIP to provide for a two tons/year uncontrolled emissions threshold for tank emission controls statewide?

4. Whether the AQCC should modify the proposed rules to disallow the use of flaring to control emissions at oil and gas production facilities except when authorized by the COGCC?

5. Whether the proposed rules effectively advance HB1261's mandate of reducing greenhouse gas emissions in Colorado?

LIST OF WITNESSES

The CACHC does not intend to call witnesses, but reserves the right to cross-examine any witness and provide testimony and exhibits as rebuttal.

Submitted this 5th day of November 2019.

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WildEarth Guardians

Joe Salazar
Colorado Rising

Micah Parkin and Deborah McNamara
350 Colorado

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Laura Fronckiewicz
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CERTIFICATE OF SERVICE

The undersigned certifies that on November 5, 2019, a true and correct copy of CACHC's Prehearing Statement was delivered via electronic mail to the following parties:

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Article

Impact of U.S. Oil and Natural Gas Emission Increases on Surface Ozone Is Most Pronounced in the Central United States

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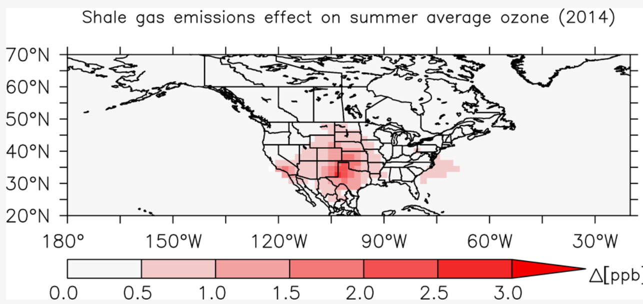
ABSTRACT: Observations of volatile organic compounds (VOCs) from a surface sampling network and simulation results from the EMAC (ECHAM5/MESSy for Atmospheric Chemistry) model were analyzed to assess the impact of increased emissions of VOCs and nitrogen oxides from U.S. oil and natural gas (O&NG) sources on air quality. In the first step, the VOC observations were used to optimize the magnitude and distribution of atmospheric ethane and higher-alkane VOC emissions in the model inventory for the base year 2009. Observation-based increases of the emissions of VOCs and NO_x stemming from U.S. oil and natural gas (O&NG) sources during 2009−2014 were then added to the model, and a set of sensitivity runs was conducted for assessing the influence of the increased emissions on summer surface ozone levels. For the year 2014, the added O&NG emissions are predicted to affect surface ozone across a large geographical scale in the United States. These emissions are responsible for an increased number of days when the averaged 8-h ozone values exceed 70 ppb, with the highest sensitivity being in the central and midwestern United States, where most of the O&NG growth has occurred. These findings demonstrate that O&NG emissions significantly affect the air quality across most of the United States, can regionally offset reductions of ozone precursor emissions made in other sectors, and can have a determining influence on a region's ability to meet National Ambient Air Quality Standard (NAAQS) obligations for ozone.



INTRODUCTION

During 2010−2015, the combined U.S. oil and natural gas (O&NG) production grew at an unprecedented rate (Supplemental Information (SI) Figure 1), making the United States the largest O&NG producing nation in the world. This growth was stimulated by new technologies, in particular hydraulic fracturing, which enabled the exploration of previously uneconomical shale plays. Atmospheric emissions from heavy drilling equipment, power generation at drill sites, trucking, and controlled and fugitive emissions from well sites, have received attention because of their lasting and reoccurring impacts on air quality, atmospheric chemistry, and climate, from local to global scales.[1−4] Accidental releases, such as during the 2015−2016 Aliso Canyon natural gas blowout, can cause large episodic injections of pollutants into the atmosphere with severe short-term impacts on air quality and human health in the immediate surroundings.[5,6]

Among the pollutants of concern are primary fossil-fuel hydrocarbons, i.e., methane and nonmethane volatile organic compounds (VOCs), as well as nitrogen oxides (NO_x), and black carbon emissions from diesel combustion and flaring.[1,3,7] Measurements within and downwind of O&NG basins have shown at times highly elevated atmospheric levels of VOCs.[8−12] Ground-based monitoring and remote sensing observations have also revealed increased NO_x.[13,14] While elevated VOC levels have been attributed mostly to fugitive emissions from oil and gas drilling, increases in NO_x can be linked to flaring, on-site power generation, and heavy trucking associated to drilling and establishing of the production infrastructure. O&NG emissions have been predicted to contribute to summertime photochemical ozone production based on their chemical reactivity,[15−17] as well as by regional photochemical modeling.[18−22] Two modeling studies have pointed out regional variability of the ozone effects, with potential ozone benefits from the transitioning of coal to O&NG power production.[23,24] O&NG emissions not only foster ozone chemistry during the summer ozone season but also can drive ozone production during snow-covered conditions in winter when ozone precursors are trapped in a shallow surface layer. The high albedo of the snow enhances solar irradiance and increases radical production from carbonyl photolysis, which in turn promotes ozone production.[25−28] As a consequence, the sparsely populated but heavily drilled Uintah Basin reported the highest number of exceedances of

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the U.S. National Ambient Air Quality Standard (NAAQS) for ozone within the whole United States in 2013,[26,28] thereby challenging the common view of ozone being exclusively a summertime pollution problem. Comparison studies between model outputs and observations of surface ozone levels have pointed to higher top-down flux estimates in O&NG drilling regions than inventory emission estimates,[27,29,30] indicating that modeling based on these inventories has likely tended to underestimate the influence of O&NG emissions on local and regional ozone.

The recent increases seen in the ozone precursor emissions suggest a possible increasing contribution of O&NG emissions to local and regional ozone production, bearing the potential to offset ozone pollution mitigation gains made in other emission sectors.[8] This has brought increasing attention to the role of O&NG emission and their possible compromising role in a region's ability to comply with NAAQS regulations for ozone.[22,31,32] Premature deaths from ozone and PM2.5 resulting from a medium O&NG emission scenario were predicted to increase by 200−460 annually for the Marcellus and Utica shales alone.[22] On the U.S. national scale, premature deaths due to exposure to ozone and $PM_{2.5}$ resulting from O&NG emissions have been estimated to reach 1100−2700 yr^{-1} by 2025.[33]

In a previous preliminary modeling assessment,[10] we applied estimates for increases of C_2−C_5 VOC emission from U.S. O&NG in photochemical modeling. These simulations showed the potential for O&NG emissions to result in up to 0.5 ppb mean summer ozone enhancements, with the largest effects seen over California and the central United States.[10] Here, we expanded on this work, using not only an improved total, spatial, and chemical species distribution of VOCs but also the contribution of NO_x emissions from the growth of U.S. O&NG exploration. This improved representation was then applied to derive an assessment of the regional sensitivity of O&NG emission changes, the contribution of O&NG emissions to regional exceedances of ozone NAAQS, and resulting ozone enhancements across the contiguous United States.

METHODS

VOC Observations. The considered VOC observations were from the National Oceanic and Atmospheric Administration (NOAA)/Institute of Arctic and Alpine Research (INSTAAR) Global VOC Monitoring program. This network consists of 44 global background stations within the NOAA Global Greenhouse Gases Reference Network (GGGRN), where pairs of whole air samples are collected weekly and shipped to a central laboratory in Boulder, CO, for C_2−C_7 VOC analyses.[34−36] For this study, we considered the VOC species ethane, propane, *iso*- and *n*-butane, and *iso*- and *n*-pentane, which together constitute the bulk of O&NG nonmethane VOC emissions.[16,17] A list of sites considered in this analysis is provided in SI Table 1.

Ozone Observations. Surface ozone data were from the Tropospheric Ozone Assessment Report (TOAR) data portal.[37] As the focus of this study is on the continental U.S., the data used originated primarily from U.S. sources. For the evaluation of the model runs, only sites with a "rural" characteristic[37] were considered for calculating grid averages. Monthly mean values were calculated at each site, and the data were then aggregated in 2 × 2° grid squares.[38]

Estimation of Growth Rate of U.S. O&NG Emissions. We explored several methods for estimating the rate of increase in U.S. O&NG VOC emissions:

(1) During 2009−2014, U.S. oil and natural gas production increased by 64 and 21%, respectively (SI Figure 1). A simple approach would be to use these growth rates as a surrogate for the emission increase, based on the assumption that emissions scale linearly with the production volume. This assumption is supported by data from a site downwind of the Marcellus Shale, where median ethane measured over four years correlated with the reported shale gas production with an r^2 of 0.59.[9] For the combined oil and natural gas emission increase, one would need to weight these emissions by the relative fraction that oil versus natural gas emissions contributes to total O&NG emissions. An inherent uncertainty is the assumption that the development and production of a new well, mostly due to hydraulic fracturing extraction technologies, are subject to the same fugitive emission loss rate as conventional extraction technologies. This has been questioned by some studies that have pointed out higher emission rates from hydraulic fracturing than from conventional drilling operations.[39−42]

(2) For some O&NG development regions, direct measurements of VOC concentrations provide estimates for O&NG VOC emission rate increases. Increasing atmospheric mole fractions of O&NG-associated VOCs have been reported downwind of the Marcellus Shale[9] and from several sites downwind of O&NG fields in Texas.[8] Data from the GGGRN sites that are near/downwind of O&NG basins show a clear influence from nearby O&NG development and have the highest rates of ethane and propane increase. Rates of increase at Park Falls, Wisconsin, a site downwind of the Bakken Shale, North Dakota, are 7.9 and 13.1% yr^{-1} for ethane and propane, respectively, for June 2009−June 2014. Rates of increase at Southern Great Plains, Oklahoma, a site within the Woodford Shale, are 10.7 and 10.5% yr^{-1}. For Southern Great Plains, similar magnitude growth rates have also been reported for the butane and pentane isomers.[12]

(3) A number of recent publications have developed estimates of the tropospheric ethane increase based on column Fourier transform infrared (FTIR) spectroscopy measurements.[10,43−45] These observations are primarily from remote and/or high elevation sites and are therefore most representative of the ethane growth in the background atmosphere. A review of four publications with a total of ten data sets from seven Northern Hemisphere (NH) sites yields ethane mean/median rates of change of 4.3/4.6% yr^{-1} (SI Table 2). Based on the geographical pattern of increases seen in the shorter-lived propane, the authors argued that this NH troposphere ethane increase largely stems from O&NG emission increases in the United States.

The modeling work presented here was based on the emissions growth that is outlined under point (3) above, which is a lower/conservative emission growth estimate, in comparison to the data and assumptions under (1) and (2). This emission growth was further evaluated by comparison between model and observations as detailed below.

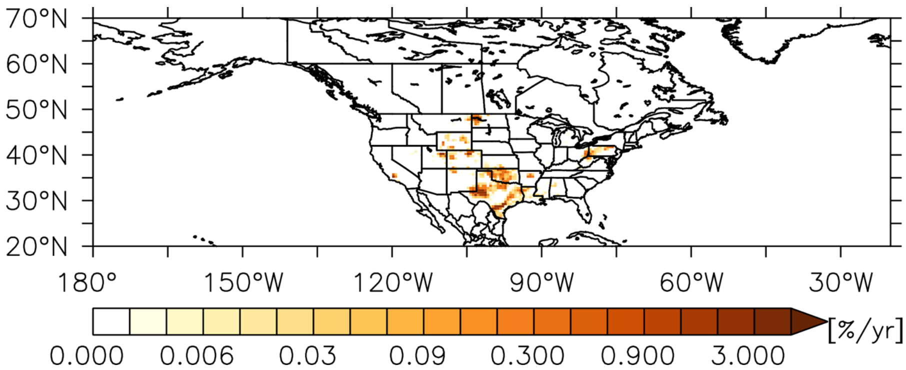

Figure 1. Distribution of O&NG emissions in the continental United States that were added to the model simulations. The color bar shows the emission increase as a fraction of the total (in 2009) in % per year.

Model. We applied the fifth-generation European Centre Hamburg general circulation model (ECHAM5[46]), version 5.3.02, MESSy, version 2.52.0, in the T63L31 resolution, i.e., with a spherical truncation of T63 (corresponding to a quadratic Gaussian grid of approx. 1.9 × 1.9° in latitude and longitude), with 31 vertical hybrid pressure levels up to 10 hPa. Treatment of aerosols has been described previously.[47−49] The model was used in its Chemistry-Transport Model configuration,[50] i.e., without feedback between chemistry and transport. The model was nudged[51] toward the European Centre for Medium-Range Weather Forecast (ECMWF) reanalysis data (ERA-interim,[52]); simulations are covering the period 2009−2014. Further descriptions and evaluations of the ECHAM5 chemistry and model are presented in the literature.[49,53−57] The chemistry mechanism for consideration of the O&NG VOCs was the same as detailed previously,[10] but augmented to include oxidation chemistry of simple C_4−C_5 hydrocarbons (*n*- and *iso*-butane and *n*- and *iso*-pentane), as described in Pozzer et al.[49] Further, a simple mechanism for toluene chemistry was adopted, similar to the approach of Lelieveld et al.[58]

The model simulations adopted emissions from the RCP85 database (Representative Concentration Pathway 8.5),[59] scaled as described in Pozzer et al.[60] To improve the agreement between model results and the observations from VOC monitoring, ethane emissions were further increased by 50% for all emission sources at latitudes north of 20°N. The resulting ethane emissions are as follows: in the NH, 12.1 Tg yr^{-1} of ethane is emitted by anthropogenic sources, 0.2 Tg yr^{-1} by biogenic sources, and 0.9 Tg yr^{-1} by biomass burning, totaling 13.2 Tg yr^{-1} for 2009. With the adjusted emissions, model outputs for the year 2009 agreed with GGGRN observations generally within 10% to the observations (average bias for all the stations worldwide) (SI Figure 2). The adjusted ethane emissions were therefore considered as our default emissions in this work. The propane, butane, and pentane emissions agree with the GGGRN observational data set as shown in Pozzer et al.[49]

Modeled O&NG Emissions. In addition to the standard sector present in the RCP85 database, updated emissions from the O&NG sector were included. The emission map was based on shale O&NG well distribution, available at https://fracfocus.org, which is a different approach than our previous work.[61] This database was considered the most complete, with approximately 2.5 million total well sites registered. This well inventory includes both active and inactive wells. This differentiation will likely only have a minor influence on the results, as the location and density of the wells are deemed to be reasonably proportional to the location of extraction activity, and the relatively large grid scale in the model reduces the uncertainties associated with the relative distribution of retired wells. We assumed that all wells emit the same amounts of VOCs and the same VOC signatures, neglecting differences in well production and leakage rates. Finally, the distributed well map was aggregated in a 0.5 × 0.5° regular map, and emissions were scaled based on the well number density in each grid cell. The resulting emissions map (Figure 1) identifies regions that have experienced recent growth of O&NG development, with regions of large emission increases mostly in the central and northeastern United States.

As enumerated above, we applied an O&NG emission growth rate of ethane of 0.42 Tg/yr^{-2}, consistent with our previous work[10] and equivalent to a ∼17% increase of O&NG emissions over the five-year window (2009−2014). Based on the VOC ratios presented in,[10] we estimated 0.42, 0.30, 0.11, 0.08, 0.05, 0.06, and 0.15 Tg yr^{-2} increases for ethane, propane, *n*-butane, *iso*-butane, *n*-pentane, *iso*-pentane, and toluene emissions every year for five years, respectively. This emission adjustment reflects a global anthropogenic ethane flux increase from 13.2 Tg yr^{-1} in 2009 to 15.3 Tg yr^{-1} in 2014.

Several other recent studies have identified a low bias of O&NG emissions in inventories and proposed inventory emission increases. Our estimates of 13.2 and 15.3 Tg yr^{-1} global ethane emissions for 2009 and 2014, respectively, reflect progressively higher global ethane fluxes similar to other recently updated inventory estimates (i.e., 18.7 Tg yr^{-1} (global, 2014),[45] 12.6 Tg yr^{-1} (global, 2010),[62] and 20 Tg yr^{-1} (global, 2011)).[63]

Although most of the global VOC emission increase identified by Helmig et al.[10] is probably from emissions in the United States, other global regions may have contributed to the flux increase. To reflect and compensate for this uncertainty, VOC emissions $>C_5$ were excluded as they could not unambiguously be identified as emitted by O&NG. Their relative fraction (of total VOCs) can vary over a wide range; on average, they constitute on the order of 10% of the total O&NG VOC emissions.[16,17,64] These longer chain and aromatic VOC generally have higher reactivity and ozone production potential than the lighter nonmethane hydrocarbons (NMHCs).[65]

The methane data were nudged[66] on the surface mimicking the observed values for the simulated period. Although the background methane oxidation is considered in the model, we did not consider increases in regional O&NG methane

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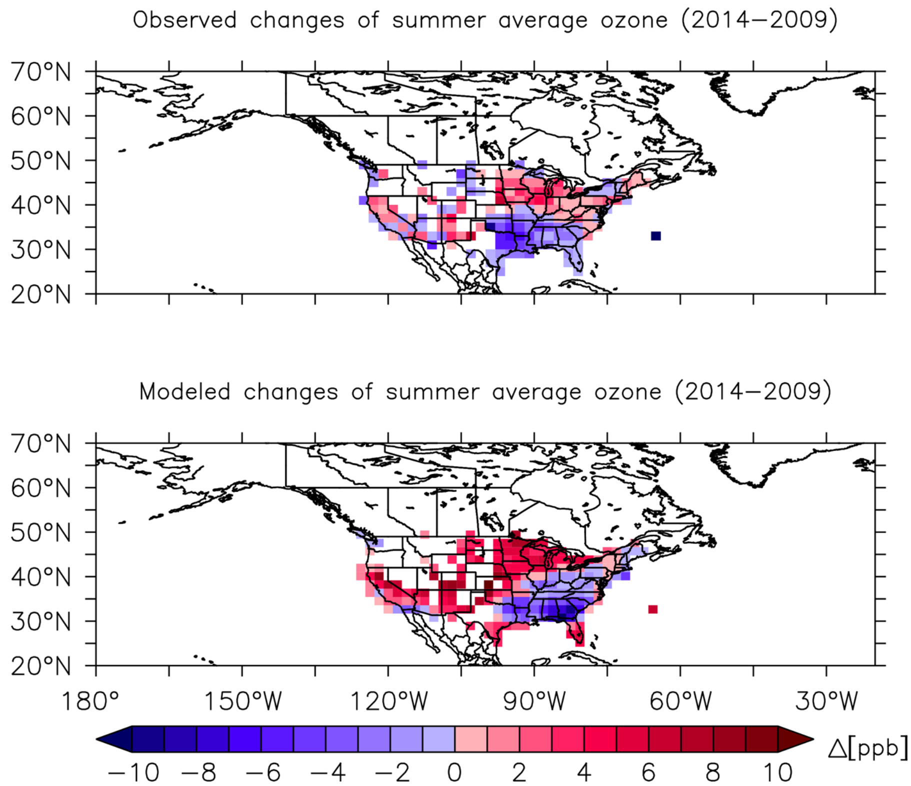

Figure 2. *Model_Run_O&NG_Trend* output for 2014–2009 mean summer ozone changes (top) compared to the ozone changes over the same time interval seen in Tropospheric Ozone Assessment Report (TOAR)[37] data extracted for grid cells with available observations (bottom). The corresponding model output for the entire domain is available in SI Figure 6.

emissions, which can have a further impact on regional ozone production.[67,68] The disregard of emissions of the O&NG longer chain (>C_5), aromatic VOCs, and methane emissions, make it more likely that the results for the estimated O&NG ozone production increase are a lower limit.

In addition to VOCs, O&NG operations also emit nitrogen oxides (NO_x).[13,14] The NO_x emission rates from oil and gas hydraulic fracturing well site development stem from a variety of diverse sources that depend on operator practices and State regulations. The relative ratio of NO_x/VOC emissions from O&NG operations can be quite variable, depending on the abundance and technology of flaring, power generation, and other industry practices,[7,13,69] as well as emissions from the traffic at well sites.[70] Resulting emission rates are likely highly variable, and at this time poorly defined and uncertain. Here, we chose a representation of NO_x emissions in our simulations based on Ahmadov et al.[27] and applied their estimated bottom-up NO_x/VOCs mass emission ratio of 0.023, which we considered the best available estimate for the time represented by the modeling window. We applied this ratio to a total VOC O&NG emission increase estimate of 1.2 Tg yr^{-2}.[10] resulting in a 0.026 Tg yr^{-2} increase of O&NG NO_x emissions, emitted as NO in the model. Potential NO_x emission reductions from the conversion of coal to O&NG power production and potentially associated ozone benefits[23,24] are considered in RCP85.

Model Sensitivity Runs. ECHAM5-MESSy tends to overestimate surface ozone in comparison to observations,[71] similar to what has been noted for other chemistry−climate models.[72,73] Because of the recognition of this potential bias, we intentionally avoided building interpretations on modeled absolute ozone results. Instead, we determined the sensitivity to emission changes from relative differences between model run scenarios. The absolute bias cancels out in these calculations, making results more robust since they are relatively immune to the bias in modeled absolute ozone. In this work, three numerical simulations were performed with the model.

Model_Run_Constant. All emissions were kept constant throughout the years 2009–2014 (i.e., every year has the same emissions as the year 2009). This simulation served as a baseline to determine the effect of meteorology alone on the ozone changes over the investigation period.

Model_Run_RCP85. All emissions were following the RCP85 database as described above, without any new O&NG emissions.

Model_Run_O&NG_Trend. The same as the *Model_Run_RCP85* simulation, with C_2–C_5 NMHC, toluene, and NO_x emissions from shale gas emissions added, increasing from May 2009 to May 2014 as discussed above. (Please note that changes in a reactive and highly variable gas such as ozone over a five-year window may not necessarily imply a "trend." While we avoided the use of the word "trend" in the text, this term was designated as a label for the model runs that used the increasing O&NG emissions.)

NAAQS Exceedances and Ozone Increase Rates. The NAAQS exceedances were calculated as the number of days in a year when the daily maxima of 8-h running mean for ozone exceeded 70 × 10^{-9} mol/mol (ppb), following the U.S. Environmental Protection Agency (EPA) definition (www.epa.gov/outdoor-air-quality-data/air-data-ozone-exceedances). The 2009–2014 rates of change in ozone were calculated following the NOAA trend analysis tool,[74] as described

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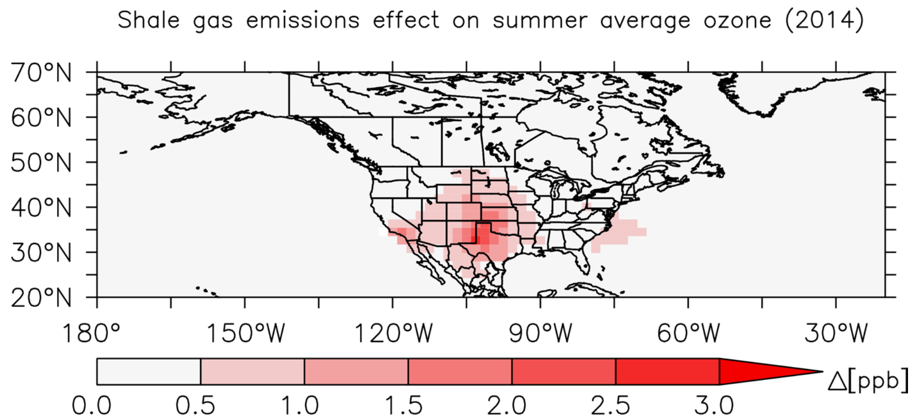

Figure 3. Difference in summer 24 h mean surface ozone between the *Model_Run_O&NG_Trend* versus the *Model_Run_RCP85* simulation for the year 2014. These results reflect the impact of added O&NG emission on surface ozone.

previously,[10] both for the model and the observational data sets.

RESULTS AND DISCUSSION

Model Evaluation. The ethane model results of the simulation that gave the closest agreement with the data (*Model_Run_O&NG_Trend)* reproduced the observed ethane mixing ratios for most comparisons within 10% (SI Figure 2). Further, the ethane rates of concentration increase that were calculated from the data and the modeled rates of increase were compared for each location for the years 2009−2014 (SI Figure 3). In total, 91% of the results from both methods agree in the sign of the rate of change (increase) and 48% within a factor of two (modeled rate of increase relative to the observed value between 0.5 and 2). It needs to be emphasized that due to the variability in the data, and the relatively short (5 years) time window that was considered, for a significant number of cases, the calculations for the rate of changes in the measurement data had a relatively high uncertainty error (see Supplementary Information to ref 10), which contributes significantly to the deviations in this comparison.

Ozone Changes during 2009−2014. Figure 2 shows the difference between the modeled summer average ozone on the surface for the year 2014 relative to 2009, with the available individual site ozone rate of change observations (SI Figure 4) assembled in each grid to match the model grid cell output. The upper graph shows the observation, and the graph underneath shows the results from the simulations (organized in the same resolution as the model grid size). Model output results are only shown for cells where observations are available to facilitate the comparison. Both analyses show large spatial differences in ozone changes during this time window. There is a good agreement (i.e., within 50%) for the southeastern United States, with ozone decreases of 2−6 ppb during the simulation period. Similarly, there is a good agreement for the central and north-central United States, where observations and the model indicate 1−7 ppb ozone increases. Overall, ozone increases in the model results are larger and geographically wider spread than in the observations. Incorporating the results from the full model domain (SI Figure 5) further emphasizes the prominence of the ozone increase across most of the North American continent, as well as North Pacific and North Atlantic.

The existence and large geographical spread of increasing ozone are rather surprising, as other recent research studies have shown long-term decreasing ozone in the continental United States and the downwind North Atlantic post year 2000.[72,75−77] Further investigation of ozone time series and rate of change analysis outputs from the selected North American ozone monitoring sites (SI Figure 6) demonstrated the cause for this at first seemingly contradictory finding: 2009 and 2010 were relatively low ozone years, followed by 2 years with above-average ozone. These ozone differences are probably linked to meteorological differences in these years that affected ozone production. Over the north-central United States, average temperatures during 2012 were approximately 1.6 K higher than those during 2009.[78] It is therefore likely that these dynamic/meteorological differences and interannual variability in meteorological conditions, in particular the perseverance of high-pressure systems, caused above-average summer temperatures and above-average surface ozone. Previous research has estimated increases of 2−6 ppb of ozone for each K increase in the temperature.[79,80] This sensitivity and these interannual weather differences most likely caused a marked upward/increasing ozone change during the 2009−2014 time period for the north-central United States that defines the long-term ozone trends. These ozone changes are therefore likely largely due to the year-to-year variability and overall relatively warmer weather during the latter part of the chosen five-year time interval and are not a reflection of long-term changes in ozone precursor emissions, including from the O&NG sector.

Effect of O&NG Emissions on Summer Mean Ozone. Using a differential atmospheric modeling approach that considered actual meteorological conditions provided estimates for added ozone production from the growth of O&NG emissions. The sensitivity study included our current best estimate of O&NG emission increases of methane, VOCs, and NO_x over the 2009−2014 growth period. To remove the influence of meteorology, the effect of the O&NG emissions on surface ozone was assessed by subtracting the 2014 model output with the scenario that did not include the O&NG emission increases, i.e., the *Model_Run_RCP85*, from the *Model_Run_O&NG_Trend* simulation. Their difference, shown in Figure 3, is insensitive to meteorological and other emission changes (as they cancel out), and therefore only show the ozone changes due to increasing O&NG emissions. There is high spatial variability in this ozone contribution across the United States. Mean summer ozone increases of ≥1 ppb are observed for more than half of the continental United States,

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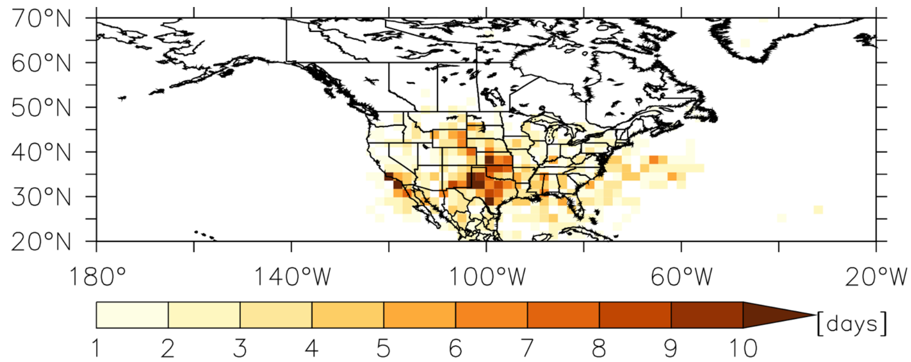

Figure 4. Simulated number of additional days with 8 h summer ozone in 2014 above 70 ppb due to the O&NG 2009−2014 emission increase. Shown are the differences from the *Model_Run_O&NG_Trend* versus the *Model_Run_RCP85* simulations.

with the highest effect seen in the central United States, specifically in Northern Texas, New Mexico, Oklahoma, and Colorado, where ozone increases of up to 3 ppb are modeled. Ozone increases of 1−2 ppb are also modeled for Southern California. Increases of 0.5−1 ppb are seen over the Atlantic downwind of U.S. southeastern states.

These summer ozone increases are ∼20% higher than our previous estimates,[10] which is primarily due to the combined inclusion of O&NG emissions of higher VOCs and NO_x. This relatively small difference illustrates that the contribution of the O&NG NO_x emission is relatively small (<20%) compared to the O&NG VOC emissions. Furthermore, the increases in ozone are now more pronounced in the central United States, reflecting the updated distribution of emissions increase. Notable ozone increases are also seen over selected areas in southern California. This finding is a bit surprising, as emission increases in California are relatively small (Figure 1). This high sensitivity is primarily due to high NO_x conditions in this region, which causes relatively modest increases in VOC emissions to have a relatively large influence on ozone production.

Two other previous studies have provided estimates of the recent O&NG increase in U.S. surface ozone. Kort et al.[21] show a sensitivity study that considered fugitive alkane (C_2 and higher) emissions from the Bakken Shale only. For one particular day in August 2014, they calculated ozone increases at and downwind of the primary emission locations in North and South Dakota, and eastern Montana, reaching 2 ppb. Tzompa et al.,[81] applying updated O&NG emission fields to the GEOS-Chem CTM, predicted daytime summer ozone increases of up to 4 ppb, with the strongest effect seen over the central United States, which is reasonably consistent with our findings.

Effect of O&NG Emissions on Regulatory Summer 8-h Mean Ozone Metrics. The U.S. ozone compliance with NAAQS is defined by the "Design Value," which is calculated as the mean of three consecutive years of the fourth highest annual value for the daily maximum average 8-h ozone value (MDA8).[82] As we simulated a limited amount of years, we decided instead to estimate the number of days for individual years when the MDA8 exceeded 70 ppb, which is a metric also largely used by the EPA.[83] For instance, for the year 2014, the model predicts that the ozone production from the added O&NG emissions caused 0−10 additional days when the MDA8 exceeded 70 ppb over regions in the contiguous United States, with 90% of the United States affected by at least one additional exceedance day (Figure 4).

Additional exceedance days from the growth of the O&NG emissions are observed in most of the continental United States, with the exception of Alaska. Approximately 90% of the contiguous United States experienced at last one additional day with 8 h surface ozone >70 ppb. These results for ozone standard exceedance days display a higher regional sensitivity than the previously reported results for average ozone increases.[33,81] It must be stressed that these results are rather sensitive to the particular regional meteorological conditions in the chosen model year. The chosen year 2014 was, for instance, a relatively low ozone year in the central United States ([32],[84] SI Figure 6), which would tend to produce a relatively lower number of ozone exceedances for that region and particular year. It must, however, also be stressed that the model in general tends to overpredict the absolute ozone concentrations on the surface (see the discussion above and ref[71]), which has the effect of overestimating the absolute number of MDA8 exceedances compared to the EPA observations. This is particularly pronounced in the few comparison locations in the central-southern United States, whereas a relatively better agreement was found for the western regions (see also section "Policy Implications" for a discussion on uncertainties). For estimating this bias, we performed an alternative calculation, where the year 2014-modeled ozone from the added O&NG emission was subtracted from the observational data. This resulted in a sensitivity of -1−12 exceedance days (compared to 0−28 days) and an overall lower fraction of the stations with an increase of at least one exceedance day, i.e., ∼5 vs 67%. There is a notable overlap of regions with a high number of added high ozone days and areas that are in nonattainment with the ozone NAAQS (SI Figure 8). The impact is most pronounced on a wider geographical scale in the central United States. Hence, although meteorology is the main driver of ozone increase in the 2009−2014 period, the O&NG emissions have the effect of further promoting possible ozone NAAQS exceedances in this region.

A preliminary assessment of the health effects projected on the order of 320 (298−344 at a confidence level of 95%) additional premature deaths from the added ozone per year (SI Text 1; please note that this mortality estimate does not include possible reductions in mortality from the decreased emissions that result from the transition of coal- to natural-gas-powered electricity-generating plants). According to the assessment in Fann et al.,[33] health effects from fine particulate matter produced by O&NG emission are of a similar magnitude; therefore, the total mortality rate from O&NG-

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produced ozone and PM2.5 is possibly on the order of two times the ozone estimate.

Policy Implications. A notable finding is that ozone increases are predicted across large geographical scales across most of the United States. This also includes numerous regions and States that do not have seen significant increases of O&NG industries within their own borders. Results reflecting a smaller, i.e., regional geographical scale bear a higher uncertainty due to the relatively coarse ($1.8 \times 1.8°$, i.e., ~200 km × ~200 km) model resolution. Additional sources of uncertainties include the neglect of the contribution of ozone production from regional methane emissions, the omission of higher O&NG VOC species, and a conservative emission growth estimate (see above) for primary O&NG development regions. Diurnal ozone production occurs on time scales that are shorter than the transport scales and mixing regimes within the model grids; consequently, ozone production and exceedances can be higher or lower at selected locations within a grid. It is therefore likely that our O&NG ozone production estimates are over predictions in some regions and under predictions in other regions. It is well possible that a higher number of added exceedances occur on smaller geographical scales and in closer proximity to emission sources. Further, our investigations exclusively focused on summer ozone, as winter ozone chemistry under conditions of surface snow cover, low boundary layer heights, and the particular chemical conditions, resulting in high ozone production rates, is currently not well presented in the model. Elevated ozone and NAAQS exceedances during winter have been observed in the Uintah Basin, Utah, and Upper Green River Valley, Wyoming. These conditions and events were not included in this evaluation. Consequently, our estimates of the increased O&NG emissions on ozone and air quality regulation compliance, excluding these winter ozone episodes must be taken with caution, and are likely a low estimate of the year-round impacts of emissions on ozone air quality in these O&NG basins.

This research had the objective to investigate the regional to large-scale effects of increased O&NG emission by a differential modeling approach. An inherent weakness stems from the lack of regional/basin specific emission speciation and emission rates. Regulations on O&NG operation and emission controls vary by states, and the rate of controlled and fugitive emissions varies widely depending on many conditions, including the chemical composition of the petroleum reservoir, operator equipment, practices, and on the stage of well development.[85] Our modeling attributed emissions equally among all reported wells, neglecting any of these dependencies, which contribute to the uncertainty in the regional sensitivity of our findings. There is also the potential of a reduction in ozone precursor emissions in the proximity and downwind of electrical power plants that were converted from coal to gas as a consequence of the lower cost and readily available gas for power generation.[24] As stated by the authors of this publication,[24] the combined effects will likely vary regionally depending on the location and overlap of O&NG basins and processing facility in relation to the location of power generation plants, and need to be evaluated on a regional case-by-case basis.

Our studies demonstrate that the assessment of air quality impacts of the rapidly growing U.S. O&NG industry would largely benefit from a more accurate characterization of the chemical emissions and their regional variations. Further, policy implementation for emission reductions from O&NG industries bear the potential to reduce ozone production and improve air quality within, and in adjacent and downwind areas, including neighboring states. These reductions would be particularly advantageous for several ozone non-attainment areas to reach compliance with the ozone NAAQS[18,21,86−88] and would furthermore be beneficial for downwind regions across wide areas of the United States.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.9b06983.

> List of sites, sorted by latitude, within the GGGRN (Table 1); growth rate of atmospheric ethane (Table 2); oil and natural gas production trends in the United States (Figure 1); comparison of Global Greenhouse Gas Reference Network observations with the *Model_Run_O&NG_Trend* simulation results (Figure 2); comparison of GGGRN ethane trends (Figure 3); year 2009−2014 surface ozone trends at TOAR sites (Figure 4); 2009−2014 mean summer ozone changes (Figure 5); ozone output from the model for a midwestern U.S. location (Figure 6); enlargements of results shown in Figure 3 (Figure 7); U.S. map showing counties that as of September 2018 were in nonattainment of the 2015 ozone NAAQS (Figure 8); and mortality estimate (Text 1) (PDF)

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Notes

The authors declare no competing financial interest.

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Early Action Compact

Ozone Action Plan

Proposed Revision to the State Implementation Plan

Prepared by the

Regional Air Quality Council

in cooperation with the

Air Pollution Control Division

DRAFT
February 11, 2004

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INTRODUCTION

State and regional agencies in the Denver metropolitan area entered into a voluntary agreement with the U.S. Environmental Protection Agency in December 2002 that lays out a process for achieving attainment with EPA's new 8-hour ozone standard in an expeditious manner. Called an Early Action Compact for Ozone ("the EAC"), the agreement sets forth a schedule for the development of technical information and the adoption and implementation of the necessary control measures into the state implementation plan (SIP) in order to comply with the 8-hour standard by December 31, 2007 and maintain the standard beyond that date.

This document, the Early Action Compact Ozone Action Plan ("EAC Ozone Action Plan") contains the enforceable plan required by the Early Action Compact for bringing the front range 8-hour ozone control area into attainment with the 8-hour standard.

NATIONAL AMBIENT AIR QUALITY STANDARDS FOR OZONE

The Federal Clean Air Act (CAA) is the comprehensive law that regulates airborne emissions from area, mobile, and stationary sources nationwide. This law authorizes the EPA to establish NAAQS to protect public health and the environment. The EPA currently has two NAAQS for ozone, the 1-hour peak standard and the 8-hour standard.

1-Hour Standard and the Denver Metropolitan Area

An area must have a monitored hourly peak ozone concentration below 0.125 parts per million (ppm) to meet the 1-hour ozone standard. If an area exceeds the standard more than three times in three years, it is subject to a nonattainment designation.

The Denver metro area has not violated the 1-hour standard since 1988, and the area was redesignated to attainment for the 1-hour ozone NAAQS on September 11, 2001 (effective October 11, 2001).

8-Hour Standard and the Front Range Area

In 1997 EPA established a new, more stringent standard for ozone. The new 8-hour standard is set at a level of 0.08 ppm (or 80 parts per billion) averaged over an eight-hour period. To take into account extreme and variable meteorological conditions that can influence ozone formation, a violation of the standard occurs when the three-year average of the fourth maximum values at a monitor exceeds the federal standard. Due to rounding of monitoring values, a violation occurs when the three-year average is equal to or greater than 0.085 ppm.

During the past several years, public education, outreach and voluntary measures have been implemented in the front range area as ozone concentrations have approached and occasionally exceeded the value permitted by the 8-hour ozone NAAQS. Based on the 2000-2002, 3-year average, the Denver metro region demonstrated compliance with the 8-hour ozone NAAQS. However, in summer 2003, elevated values of 8-hour ozone caused the Denver metro region 3-year average to violate the 8-hour ozone NAAQS in 2001-2003.

In April 2004, EPA will designate and classify areas of the country that violate the 8-hour standard. Based on the most recent three years of data (2001-03), the front range 8-hour ozone control area is slated to be designated non-attainment by EPA. However, by implementing the Early Action Compact, EPA will defer the non-attainment designation as long as region continues to meet the terms of the agreement and demonstrates attainment by December 31, 2007. Failure to meet the obligations of the agreement will result in immediate reversion to the traditional nonattainment process.

EARLY ACTION COMPACT FOR OZONE

EPA Early Action Compact Protocol

EPA developed the Protocol for Early Action Compacts (EAC Protocol) on June 19, 2002, supplemented on October 18, 2002. In exchange for relief from certain provisions of the nonattainment area requirements, the protocol establishes a two-step process that offers a more expeditious time line for achieving the 8-hour ozone standard than expected under EPA's 8-hour ozone standard implementation rulemaking.

The principles of the EAC Protocol to be executed by Local, State and EPA officials are:

- Early planning, implementation, and emission reductions leading to expeditious attainment and maintenance of the 8-hour ozone standard;
- Local area control of the measures to be employed, with broad-based public input;
- State support to ensure technical integrity of the early action plan;
- Formal incorporation of the early action plan into the state implementation plan (SIP);
- Deferral of the effective date of nonattainment designation and related requirements so long as all terms and milestones are met; and

- Safeguards to return areas to traditional nonattainment SIP requirements should terms and/or milestones are unfulfilled, with appropriate credit given for emission reduction measures implemented.

When EPA's 8-hour implementation guidelines call for designations, EPA will defer the effective date of any nonattainment designation and related requirements for participating areas that fail to meet the 8-hour ozone standard as long as all terms and milestones of the compact are being met. If the nonattainment designation is deferred, EPA will move expeditiously to designate the area as attainment and impose no additional requirements, provided that the monitors in the area reflect attainment by December 31, 2007.

If at any time the area does not meet all the terms of the compact, including meeting agreed-upon milestones, then it will forfeit its participation and its attainment or nonattainment designation (or redesignation if necessary) will become effective. The EPA will offer such an area no delays, exemptions or other favorable treatment because of its previous participation in this program.

If the area violates the standard as of December 31, 2007, and the area has had the effective date of any nonattainment designation deferred, such nonattainment designation will become effective. The State must then submit a revised attainment demonstration SIP revision according to the Clean Air Act (CAA) and EPA's 8-hour implementation rule, unless the 8-hour implementation schedule requires SIPs from 8-hour nonattainment areas before December 31, 2008. In that event, a revised attainment demonstration SIP revision for the participating area will be due as soon as possible but no later than December 31, 2008. In no event will EPA extend the attainment date for the area beyond that required by the CAA and/or EPA's 8-hour implementation rule. The region will not be allowed to renew this EAC after December 31, 2007, or to initiate a new compact if it has previously forfeited its participation.

Denver Area Early Action Compact

In December 2002 state and regional agencies with responsibilities for air quality and transportation planning in the Denver metro area entered into a Memorandum of Agreement (MOA) with EPA Region 8 consistent with terms specified in the EPA's EAC Protocol. Signatories to the agreement were:

- Denver Regional Air Quality Council (RAQC)
- Colorado Air Quality Control Commission (AQCC)
- Colorado Department of Public Health and Environment (CDPHE)
- Denver Regional Council of Governments (DRCOG)
- Colorado Department of Transportation (CDOT)
- U.S. Environmental Protection Agency, Region 8

- In December 2003, in a letter to the Governor of the State of Colorado, the EPA proposed including a total of 11 counties in the north front range 8-Hour Nonattainment Area, including the 8 counties listed in the Denver/Boulder/Greeley consolidated statistical metropolitan area (CMSA), plus Larimer, Morgan and Elbert counties. In January and February 2004 the county commissioners of Weld, Larimer, Morgan and Elbert counties agreed to join the EAC and sign the MOA.

The Compact agreement established several planning milestones that must be met for the Compact to remain in effect. These milestones are:

- June 16, 2003 – Potential state, local and other emission reduction strategies identified and described *(milestone met)*;
- March 31, 2004 – RAQC must complete a proposed EAC Ozone Action Plan and submit the plan to the AQCC for public rulemaking hearing *(milestone met with proposal to AQCC on December 18, 2003)*
- December 31, 2004 – State must complete public rulemaking hearings, adopt the EAC Ozone Action Plan as part of the SIP, and submit the plan to EPA for approval
- September 30, 2005 – EPA must take final action on the SIP submittal
- December 31, 2005 – Additional emission reduction strategies implemented no later than this date
- December 31, 2007 – Attainment of the 8-hour standard demonstrated

The Compact agreement also establishes several other requirements that must be included in the early action SIP and planning process:

Reporting

The RAQC and the AQCC will assess and report progress towards milestones in a regular, public process, at least every six months, beginning in June 2003 and concluding on December 31, 2007.

Emissions Inventories

Emission inventories used in this EAC Ozone Action Plan were developed for summer episode day for the years 2002, 2007, and 2012 using EPA's MOBILE6 emissions model and the latest transportation information; area sources using a combination of EPA's NONROAD model data, latest demographics information, local equipment populations and usage rates, area source data, and local survey and information data, and the latest stationary sources emissions information, as required by the EAC. Future year inventories will sufficiently account for projected future growth in ozone precursor emissions through 2007, particularly from stationary, area, and mobile sources.

Emissions inventories were compared and analyzed for trends in emission sources over time.

Dispersion Modeling

Base and future case dispersion modeling is required, and was performed for the EAC Ozone Action Plan. All modeling is SIP quality and performed within EPA's accepted margin of accuracy; is carefully documented; sufficiently accounts for projected future growth in ozone precursor emissions; will be concurrently reviewed by EPA; and was used to determine the effectiveness of NOx and/or VOC reductions. The control case was used to determine the relative effectiveness of different emission reduction strategies and to aid in the selection of appropriate emission reduction strategies. Modeling is based on the "Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-hour Ozone NAAQS" (EPA-454/R-99-004, May 1999). The modeling follows the guidance as facilitated by EPA Region 8.

Emission Reduction Strategies

All adopted Federal and State emission reduction strategies that have been or will be implemented by the December 31, 2007 attainment date are included in all emission inventories. The selected strategies will be implemented as soon as practical, but no later than December 31, 2005. The emission reduction strategies will be specific, quantified, permanent and enforceable. The strategies will also include specific implementation dates and detailed documentation and reporting processes.

Maintenance for Growth

The plan includes a component to address emissions growth at least 5 years beyond December 31, 2007, ensuring that the area will remain in attainment of the 8-hour standard during that period.

Public Involvement

Public involvement was conducted in all stages of planning by the signatory parties. Several stakeholder meetings were held, and public comment on the EAC Ozone Action Plan complies with the normal SIP revision and public hearing process.

AREA ENCOMPASSED BY THE EAC OZONE ACTION PLAN

At the time of the adoption of this plan by the Air Quality Control Commission, the EPA had proposed, but had not yet finalized, the boundaries of 8-hour ozone nonattainment area in Colorado. *See, EPA Responses to State and Tribal 8-Hour Ozone Air Quality*

Designation Recommendations, 68 Federal register 68805 (December 10, 2003). This EAC Ozone Action Plan shall not apply outside the boundaries for the 8-hour ozone non-attainment area finally designated by the EPA.

The area of applicability of the plan should not be confused with the geographic area of the supporting air quality analysis. The air quality analysis includes emissions inventories from most of the western United States. The area of applicability includes county inventories that may ultimately be excluded from the nonattainment boundaries and, therefore, from the scope of this EAC Ozone Action Plan. Such inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. As indicated above, the geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

INTRODUCTION IS NOT PART OF THE SIP

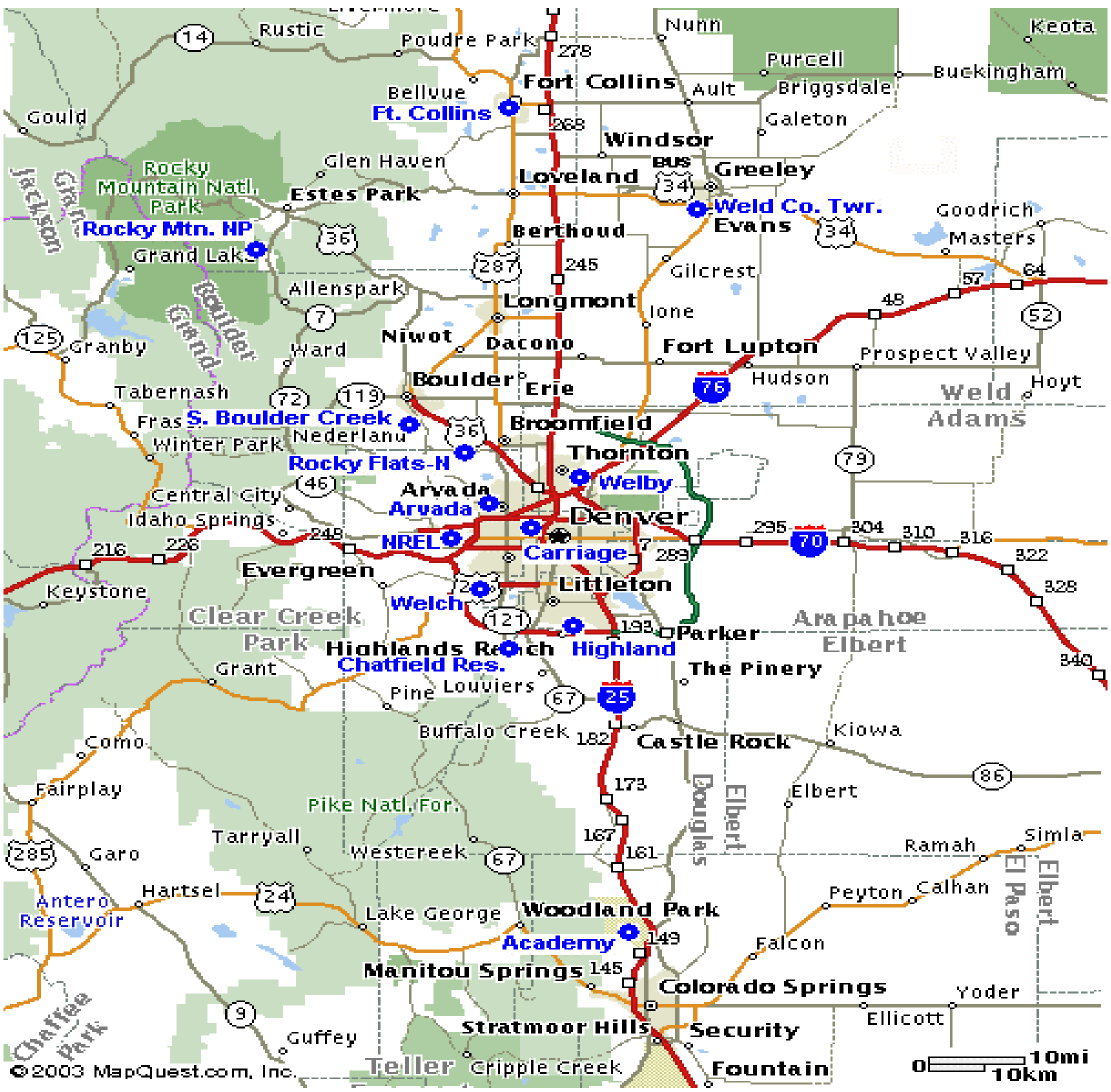
This Introduction section shall not be construed to be a federally-enforceable SIP, or incorporate the quoted provisions of the EAC into the SIP; except; however, the requirements of this plan shall not be applicable in any county or portion thereof excluded from the 8-hour ozone non-attainment area boundary by EPA as described above.

OZONE MONITORING INFORMATION

A. Ozone Monitoring Network

The current ozone ambient air monitoring network in the Denver area and along the Front Range consists of 12 stations operated by the Colorado Air Pollution Control Division (APCD) and one station operated by the National Park Service (NPS) in Rocky Mountain National Park. There have been other stations that have operated in the past. The geographical distribution of the Denver area monitors is presented in Figure 1.

Figure 1



This section shall not be construed to establish a monitoring network in the federally-enforceable SIP. EPA has already approved a monitoring SIP for the State of Colorado and this description of the ozone monitoring network shall not be construed to amend such monitoring SIP.

B. Quality Assurance Program

Ozone monitoring data for the Denver area have been collected and quality-assured in accordance with 40 CFR, Part 58, Appendix A, EPA's "Quality Assurance Handbook for Air Pollution Measurement Systems, Vol. 11; Ambient Air Specific Methods", the APCD's Standard Operating Procedures Manual, and Colorado's Monitoring SIP which EPA approved in 1993. The data are recorded in EPA's Aerometric Information Retrieval System (AIRS) and are available for public review at the APCD and through EPA's AIRS database. Table 1 presents the data recovery rates for each monitoring site in the Denver and northern Front Range area. Percent data recovery is the number of valid sampling days occurring within the "ozone season", divided by the total number of days encompassing the "ozone season". A valid sampling day is one in which at least 75% of the hourly maxima are recorded.

Table 1
Ozone Data Recovery Rates for Each Monitoring Site

Years	**Welby** Data Recovery	**Highland** Data Recovery	**S. Boulder Creek** Data Recovery	**Boulder Marine St.** Data Recovery	**Carriage** Data Recovery
1998	99%	99%	99%	99%	98%
1999	99%	98%	99%	no data	94%
2000	99%	99%	98%	no data	89%
2001	95%	90%	98%	no data	94%
2002	94%	96%	96%	no data	96%
2003	95%	96%	98%	no data	99%

Years	**Chatfield** Data Recovery	**Arvada** Data Recovery	**Welch** Data Recovery	**R. Flats North** Data Recovery
1998	84%	98%	99%	97%
1999	72%	93%	99%	97%
2000	93%	98%	94%	99%
2001	90%	99%	97%	97%
2002	94%	98%	98%	95%
2003	93%	97%	97%	99%

Table 1 (continued)
Ozone Data Recovery Rates for Each Monitoring Site

Years	NREL Data Recovery	RMNP Data Recovery	Ft. Collins Data Recovery	Greeley/Weld County Data Recovery*
1998	100%	85%	99%	97%
1999	63%	98%	93%	97%
2000	98%	94%	98%	96%
2001	96%	100%	90%	99%
2002	99%	99%	85%	99%
2003	99%	100%	97%	96%

* The Greeley monitor was moved from 811 15th St. to the Weld County site at 3101 35th Ave. in 2002.

C. Monitoring Network/Verification of Continued Attainment

The APCD has and will continue to operate an appropriate air quality monitoring network of National Air Monitoring System (NAMS) and State/Local Air Monitoring System (SLAMS) monitors in accordance with 40 CFR Part 58 to verify the attainment of the 8-hour-hour ozone NAAQS. If measured mobile source parameters (e.g., vehicle miles traveled, congestion, fleet mix, etc.) change significantly over time, the APCD will perform the appropriate studies to determine whether additional and/or re-sited monitors are necessary. Annual review of the NAMS/SLAMS air quality surveillance system will be conducted in accordance with 40 CFR 58.20(d) to determine whether the system continues to meet the monitoring objectives presented in Appendix D of 40 CFR Part 58.

D. Monitoring Data

Tables 2 and 3 below present the monitoring data for the APCD's Denver and northern Front Range monitoring sites and the NPS Rocky Mountain National Park monitoring site. For each site, the fourth maximum 8-hour ozone concentrations along with the 3-year averages of the 4th maximum concentrations at each site are presented.

Table 2
4th Maximum 8-Hour Ozone Values

	AIRS #	**1996 8-hr. O3 4th Max. (ppm)**	**1997 8-hr. O3 4th Max. (ppm)**	**1998 8-hr. O3 4th Max. (ppm)**	**1999 8-hr. O3 4th Max. (ppm)**	**2000 8-hr. O3 4th Max. (ppm**	**2001 8-hr. O3 4th Max. (ppm**	**2002 8-hr. O3 4th Max. (ppm**	**2003 8-hr. O3 4th Max. (ppm)**
Welby	08-001-3001	0.074	0.071	0.083	0.071	0.062	0.064	0.068	0.066
Highland	08-005-0002	0.073	0.065	0.084	0.075	0.076	0.077	0.076	0.091
S. Boulder Creek	08-013-0011	0.075	0.072	**0.089**	0.075	0.072	0.071	0.078	0.082
Carriage	08-031-0014	0.068	0.066	**0.085**	0.068	0.071	0.072	0.073	**0.085**
Chatfield Res.	08-035-0002	0.079	0.075	0.081	0.075	0.080	0.077	0.083	**0.095**
Arvada	08-059-0002	0.073	0.070	**0.089**	0.072	0.076	0.074	0.073	0.083
Welch	08-059-0005	0.069	0.068	0.080	0.066	0.068	0.064	0.069	0.077
Rocky Flats North	08-059-0006	0.083	0.076	**0.092**	0.080	0.081	0.082	**0.088**	**0.091**
NREL	08-059-0011	0.082	0.075	**0.095**	0.080	0.083	0.081	0.081	**0.095**
Fort Collins	08-069-1004	0.066	0.064	0.072	0.063	0.070	0.067	0.072	0.075
Greeley	08-123-0007	0.070	0.069	0.075	0.069	0.069	0.074	(Shut down)	(Shut down)
Weld County Tower	08-123-0009	---	---	---	---	---	---	(0.080)	0.083
Rocky Mountain N.P.	---	0.072	0.069	0.080	0.074	0.078	0.070	**0.087**	**0.086**

Table 3
8-Hour Ozone
4th Maximum and Three-Year Average 4th Maximum Ozone Values

Site Name	**2000** 4th Max. Value (ppm)	**2001** 4th Max. Value (ppm)	**2002** 4th Max. Value (ppm)	**2003** 4th Max. Value (ppm)	**2000-02** 3-yr. Avg. 4th Max. Value (ppm)	**2001- 03** 3-yr. Avg. 4th Max. Value (ppm)
Welby	0.062	0.064	0.068	0.066	0.065	0.066
Highland	0.076	0.077	0.076	0.091	0.076	0.081
S. Boulder Creek	0.072	0.071	0.078	0.082	0.074	0.077
Carriage	0.071	0.072	0.073	0.085	0.072	0.076
Chatfield Res.	0.080	0.077	0.083	0.095	0.080	**0.085**
Arvada	0.076	0.074	0.073	0.083	0.074	0.076
Welch	0.068	0.064	0.069	0.077	0.067	0.070
Rocky Flats North	0.081	0.082	0.088	0.091	0.084	**0.087**
NREL	0.083	0.081	0.081	0.095	0.082	**0.085**
Fort Collins	0.070	0.067	0.072	0.075	0.070	0.071
Greeley	0.069	0.074	(Shut down)	(Shut down)	---	---
Weld County Tower	---	---	(0.080)	(0.083)	(0.080)	(0.081)
Rocky Mtn. N.P.	0.078	0.070	0.087	0.086	0.078	0.081

CHAPTER I: BASE CASE EMISSIONS INVENTORIES

This section presents emission inventories for this EAC Ozone Action Plan for the 8-hour ozone control area 2002 base case and the 2007 base case used in the modeling scenarios. Inventories for the 8-hour ozone control area 2007 control case modeling will be presented later in this document and will include the additional control measures that are needed to demonstrate attainment of the 8-hour ozone NAAQS. All of the base and control case modeling inventories are for all of the eight counties in the Denver/Boulder/Greeley CMSA: Denver, Jefferson, Douglas, Broomfield, Boulder, Adams, Arapahoe and Weld plus Larimer, Morgan and Elbert counties. These inventories represent emissions estimates for an average episode day during the summer ozone season (May through September).

The emission estimates were developed based on the most recent demographic data and vehicle miles traveled (VMT) estimates contained in 1) DRCOG's conformity analysis for the updated fiscally constrained element of the 2025 Regional Transportation Plan, and 2) North Front Range Transportation and Air Quality Planning Council's (NFRTAQPC) 2025 Regional Transportation Plan. Table 4 presents this information.

Table 4
Demographic Data

DRCOG Demographics	2002	2007	2012
Population	2,492,627	2,718,479	2,944,330
Households	1,083,751	1,181,947	1,280,144
Employment	1,492,115	1,636,654	1,781,192
VMT	63,493,136	70,537,153	77,362,474
NFRTAQPC Demographics	**2002**	**2007**	**2012**
Population	332,030	403,534	463,121
Households	144,360	175,450	201,366
Employment	177,880	204,951	238,791
VMT	12,433,458	14,903,717	17,052,833

The 2002 and 2007 base case modeling inventories incorporate the control measures in place at that time. Control measures in place in 2002 and assumed for 2007 include:

1. Federal tailpipe standards and regulations, including those for small engines and non-road mobile sources. Credit is taken for these federal requirements but they

are not part of the Colorado SIP. The credits change from 2002 to 2007 as EPA Tier II and low sulfur gasoline standards become effective.

2. Air Quality Control Commission Regulation No. 11 -- covering the Automobile Inspection and Readjustment (A.I.R.) program in place during the 2002 ozone season, which includes an enhanced Inspection/Maintenance (I/M). For 2007, a maximum of 50% fleet coverage is assumed for the remote sensing clean screen program in the DMA based on a proposed change in Reg. 11. Regulation No. 11 also contains state-only, basic I/M programs in the Colorado Springs and Fort Collins/Greeley areas. The computer modeling does not include any credit for the basic programs in the Colorado Springs and Fort Collins/Greeley areas and such basic programs are not part of, or being submitted for inclusion in, the SIP.

3. Air Quality Control Commission Regulations No. 3, No. 6, No. 7, and Common Provisions – covering gasoline station and industrial source control programs. The Common Provisions, Parts A and B of Regulation No. 3, and the VOC control requirements of Regulation No. 7 are already included in the approved SIP. Regulation No. 6 and Part C of Regulation No. 3 implement the federal standards of performance for new stationary sources and the federal operating permit program. This reference to Regulation No. 6 and Part C of Regulation No. 3 shall not be construed to mean that these regulations are included in the SIP.

4. Since 1991, gasoline sold in the Denver metro area during the summer ozone season (June 1 to September 15) has been subject to a national Reid Vapor Pressure (RVP) limit of 7.8 pounds per square inch (psi) in order to reduce fuel volatility. For ethanol-blended fuels, the RVP limit is 8.8 psi due to the federal 1.0 psi RVP waiver for ethanol. The EPA has granted waivers to allow a 9.0 psi RVP (10.0 psi for ethanol blends) gasoline in the Denver area instead of the more stringent 7.8 psi limit.

   For 2002, because of voluntary efforts to reduce the gasoline RVP, the RVP of the base gasoline was measured at 8.2 psi; ethanol (10% blend) market share was measured at 20%. In other words, 80% of the gasoline was at 8.2 psi RVP, and 20% of the gasoline was at 9.2 psi RVP.

   For purposes of the base case 2007 mobile source inventory, the RVP of the base gasoline is assumed to be 9.0 psi, as requested in the maintenance plan submitted by the Governor to support redesignation to attainment for the 1-hour ozone standard (Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area). The ethanol (10% blend) market share is assumed to be 25% based on future ethanol market share average projected by the industry. In other words, 75% of the gasoline is assumed to be 9.0% psi RVP, and 25% of the gasoline is assumed to be 10.0 psi RVP.

All of the inventories were developed using EPA-approved emissions modeling methods, including EPA's MOBILE6 model and local VMT data for on-road mobile source emissions, EPA's non-road model and local demographic information for area and off-road sources, and reported actual emissions for point sources. Estimates for future emissions are based on the above-mentioned tools and the EPA's Economic Growth and Analysis System (EGAS) model for estimating future point sources activity, VMT growth for on-road mobile sources, and 2007 and 2012 demographic data for off-road and area sources. The EAC Ozone Action Plan's technical support document contains detailed information on model assumptions and parameters for each source category.

Summaries of the VOC and NOx base case inventories for the 8 county and the 11 county areas, for 2002 and 2007, are presented in Tables 5a and 5b, respectively, below. Emissions of NOx and VOCs are in tons per average episode day. Additional detail on the categories of emissions can be found in the technical support document.

Wildfire Emissions Estimates

Wildfire emissions, though not included in Tables 5a and 5b, have been considered for the background ozone concentrations in the modeling effort. Wildfire emissions can vary wildly on a day-to-day basis depending on conditions. The average daily wildfire emissions in the modeling episodes are estimated at approximately 15 tpd for VOC, 323 tpd for CO and 7 tpd for NOx.

Table 5a
2002 and 2007 Base Case Emission Inventories
(tons per average episode day)
Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson and Weld Counties

Source Category	2002 VOCs (tons/day)	2007 VOCs (tons/day)	2002 NOx (tons/day)	2007 NOx (tons/day)
Flash	133.9	146.1	0	0
Gas Stations	22.3	16.0	0.1	0.1
Oil and Gas Production	4.1	4.5	0.2	0.2
Reciprocating Internal Combustion Engines	7.8	8.7	93.5	94.7
Other Stationary Sources	24.6	28.8	11.4	12.2
Total Point	**192.8**	**204.1**	**105.2**	**107.1**
Automotive After Market Products	27.2	29.0	0	0
Architectural Coatings	19.5	20.8	0	0
Household and Personal Products	17.0	18.2	0	0
Adhesives and Sealants	14.7	15.7	0	0
Pesticide Application	8.9	10.0	0	0
Other Area Sources	9.6	10.4	25.60	27.6
Total Area	**96.9**	**104.1**	**25.60**	**27.6**
Lawn & Garden	47.3	31.2	9.31	9.3
Other Off-road	25.8	22.5	78.7	73.2
Total Off-road	**73.1**	**53.7**	**87.99**	**82.5**
On-road Mobile	**152.8**	**117.5**	**157.8**	**119.3**
Total Anthropogenic	**515.6**	**479.4**	**376.6**	**336.5**
Total Biogenic	468.1	468.1	37.1	37.1
Total	**983.7**	**947.5**	**413.7**	**373.6**

Note: Inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. The geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

Table 5b
2002 and 2007 Base Case Emission Inventories
(tons per average episode day)
Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson, Weld, Elbert, Larimer and Morgan Counties

Source Category	2002 VOCs (tons/day)	2007 VOCs (tons/day)	2002 NOx (tons/day)	2007 NOx (tons/day)
Flash	134.3	147.2	0.0	0.0
Gas Stations	24.5	17.5	0.1	0.1
Oil and Gas Production	4.2	4.6	0.2	0.2
Reciprocating Internal Combustion Engines	9.0	9.9	125.8	129.7
Other Stationary Sources	28.0	30.1	14.1	15.0
Total Point	**200.0**	**209.3**	**140.1**	**144.9**
Automotive After Market Products	34.9	32.1	0.0	0.0
Architectural Coatings	25.0	23.0	0.0	0.0
Household and Personal Products	21.9	20.1	0.0	0.0
Adhesives and Sealants	18.9	17.4	0.0	0.0
Pesticide Application	15.0	13.1	0.0	0.0
Other Area Sources	15.5	14.0	36.1	32.7
Total Area	**131.2**	**119.6**	**36.1**	**32.7**
Lawn & Garden	38.3	35.0	11.4	10.4
Other Off-road	30.6	27.6	91.6	82.1
Total Off-road	**68.9**	**62.6**	**103.0**	**92.4**
On-road Mobile	**172.6**	**135.1**	**177.6**	**136.6**
Total Anthropogenic	**572.7**	**526.6**	**456.7**	**406.6**
Total Biogenic	799.5	799.5	52.3	52.3
Total	**1372.1**	**1326.1**	**509.1**	**458.9**

Note: Inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. The geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

CHAPTER II: CONTROL MEASURES

This section of the EAC Ozone Action Plan lists the additional control measures, above and beyond those assumed in the 2007 base case inventory described in Chapter 1 that are incorporated into the SIP to demonstrate attainment of the 8-hour ozone NAAQS by 2007 and maintenance of such standard through 2012. For purposes of this EAC Ozone Action Plan, and for inclusion of such control measures in the state implementation plan, the term "8-hour ozone control area" shall mean the area designated by the EPA as a deferred non-attainment area for the 8-hour ozone standard.

## A.	Reid Vapor Pressure

Since 1991, gasoline sold in the Denver area during the summer ozone season (June 1 to September 15 for gasoline RVP) has been subject to a national Reid Vapor Pressure (RVP) limit of 7.8 pounds per square inch (psi) in order to reduce fuel volatility. For ethanol blends the limit has been 8.8 psi. Since the Denver area has not violated the 1-hour ozone standard since the late 1980's, the state has requested, and EPA has granted, waivers to allow 9.0 psi RVP (10.0 psi for ethanol blends) gasoline in the Denver area instead of the more stringent 7.8 RVP limit.

Photochemical modeling analyses performed during this EAC process indicates little to no improvement in predicted ozone levels between a 7.8 and 8.1 RVP. APCD cost estimates indicate a doubling of costs to industry to provide 7.8 RVP over 8.1 RVP fuel. Because of these two considerations this EAC Ozone Action Plan proposes an 8.1 RVP fuel.

Therefore, since this EAC ozone action plan for the 8-hour ozone standard relies on an RVP level of 8.1 psi (9.1 psi for ethanol blends) in the 2007 control case inventory for the existing Denver 1-hour ozone attainment/maintenance area, the State of Colorado requests that the 8.1 psi (9.1 psi for ethanol blends) RVP level for the existing Denver 1-hour ozone attainment/maintenance area be made permanent upon approval of the EAC ozone action plan.

## B.	Condensate Tank Emissions Controls

The EAC Ozone Action Plan includes an amendment to Regulation No. 7 to require the reduction of flash emissions of volatile organic compounds from condensate collection, storage, processing and handling operations. The rule requires the installation of air pollution control technology to achieve at least a 50% reduction from uncontrolled emissions of volatile organic compounds from new and existing oil and gas exploration and production operations, natural gas compressor stations, and natural gas drip stations located within the 8-hour ozone control area designated by EPA. The rule includes an exemption if total emissions are less 30 tons per year.

C. Controls for Stationary Engines

The EAC Ozone Action Plan may includes an amendment to Regulation No. 7 to require the installation of controls on new and existing rich burn and lean burn natural gas fired stationary reciprocating internal combustion engines (RICE) larger than 500 horsepower located in the 8-hour ozone control area. In this case, controls installed for uncontrolled rich burn RICE shall be non-selective catalyst reduction and an air fuel ratio controller or other equally effective air pollution control technology, and for uncontrolled lean burn RICE shall be oxidation catalyst reduction, or other equally effective air pollution control technology.

D. Controls for Dehydrators

The EAC Ozone Action Plan includes an amendment to Regulation No. 7 to require the reduction of emissions of volatile organic compounds from new and existing dehydration towers at oil and gas operations with emissions in excess of 15 tons per year.

E. Revisions to Regulation No. 11 - Automobile Inspection and Readjustment Program

The EAC Ozone Action plan includes an amendment to Regulation No. 11 to reduce the coverage of the remote sensing clean screen area in order to reduce the disbenefit of the program and to reflect the practical reality of potential coverage. No more than 50 percent of the fleet of gasoline vehicles in the enhanced program area will be evaluated with remote sensing during any twelve-month period after December 31, 2005.

Previously adopted state-only regulations establishing hydrocarbon limits and requiring gas cap pressure checks are hereby included.

CHAPTER III: PHOTOCHEMICAL MODELING & OTHER WEIGHT OF EVIDENCE ANALYSES FOR ATTAINMENT DEMONSTRATION

A. Photochemical Modeling for the 2002 and 2007 Base Case Scenarios

Photochemical grid modeling was required and performed under the EAC Ozone Action Plan for the 8-Hour Ozone Control Area. The goal of the EAC's 8-hour ozone modeling analysis was to conduct a comprehensive photochemical modeling study for the Denver-north front range region that can be used as the technical basis for demonstrating attainment with the 8-hour ozone NAAQS.

The photochemical model "Comprehensive Air Quality Model with Extensions" (CAMx) from the consultants ENVIRON International Corporation and Alpine Geophysics Atmospheric Sciences Group was used for this study. Meteorological fields for input into CAMx were produced using the Mesoscale Meteorological Model (MM5). Model ready emissions data for the 2002 and 2007 base case were processed through the Emissions Processing System (EPS2x). The photochemical modeling study was conducted in accordance with EPA modeling guidance for ozone and a prepared modeling protocol. The modeling protocol was specifically designed to identify the processes responsible for 8-hour ozone exceedances in the region and to develop realistic emissions reduction strategies for the ozone exceedances.

Several technical documents are available that detail the meteorological, emissions, and photochemical modeling and are included in the Technical Support Document for this plan. Technical support documentation for modeling include:

- Modeling Protocol, Episode Selection, and Domain Definition
- Episode Selection for the Denver Early Action Ozone Compact
- Evaluation of MM5 Simulations of the Summer '02 Denver Ozone Season and Embedded High 8-hr Ozone Episodes
- Development of the 2002 Base Case Modeling Inventory
- Development of the 2007 Base Case Modeling Inventory
- Preliminary Photochemical Base Case Modeling and Model Performance Evaluation for the Summer '02 Denver Ozone Season and Embedded High 8-hour Ozone Episodes
- Draft Final Air Quality Modeling for the Denver EAC Ozone Compact, 2007 Base Case, Control Strategy and Sensitivity Analysis Modeling
- Draft Additional Air Quality Modeling Analysis to address 8-Hour ozone Attainment for the Denver EAC

B. Base Case Relative Reduction Factors (RRF)

The modeling produces base case relative reduction factors (RRF) for receptors in the modeling domain where ozone monitors are located. In general, the RRF for each monitor is equal to the mean 2007 base case modeled 8-hour ozone concentration divided by the mean 2002 base case modeled 8-hour concentration. Specifically, each RRF is the summation of all 2007 daily 8-hour predicted maximum concentrations greater than 0.070 ppm "nearby" (within 15 kilometers) a monitor during a given episode divided by the summation of all 2002 daily 8-hour predicted maximum concentrations greater than 0.070 ppm within 15 kilometers of the monitor during a given episode as shown below. (Based on EPA's May 1999 "Draft Guidance On the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS.")

$$\text{Relative Reduction Factor (RRF)} = \frac{\text{Mean 2007 Base Case Modeled 8-hour Ozone Conc. (ppm)}}{\text{Mean 2002 Base Case Modeled 8-hour Ozone Conc. (ppm)}}$$

An RRF for each monitoring site for modeled (predicted) days greater than 0.070 ppm is presented in Table 6.

C. Estimated Future (2007) Base Case Design Value

Once the RRFs are developed, the RRF for each monitoring site is multiplied by the monitoring site's base case design value to determine a future case design value for each site, as shown below, indicating if attainment is demonstrated at each site.

$$\text{Estimated Future Design Value (ppm)} = \text{RRF} * \text{Current Design Value (ppm)}$$

The modeling, though it has met EPA guidelines for use in the EAC process, under predicts actual monitored values by approximately 20%. This results in predicted values in the 8-hour ozone control area, for the 2002 base case less than or very close to 0.070 ppm, which approaches the levels of background ozone, which is estimated to be approximately 0.055 to 0.065 ppm. When expected emission reductions are applied in the 2007 base case or control case and modeled, the resultant predicted values are similarly very close to 0.070 ppm for many of the days. The resultant RRF calculation offers very slight incremental changes in future ozone design values due to reductions in emissions. This condition is referred to as "stiffness" in the model.

Table 6 presents the current (2001-2003) base case design values for each monitoring site, the base case RRFs for modeled days greater than 0.070 ppm, and the future base case design values for each site. If the future (2007) base case design values are less than 0.085 ppm, then attainment is demonstrated and no additional control measures are needed.

Table 6
2007 Base Case Design Values
for Each Monitoring Site
for Modeled Days greater than 0.070 ppm

Site Name	8-Hour Ozone Current (2001-2003) Base Case Design Values (ppm)	Base Case Relative Reduction Factors	8-Hour Ozone Future (2007) Base Case Design Values (ppm)
Welby	0.066	0.9988	0.0659
Highland	0.081	0.9873	0.0800
S. Boulder Creek	0.077	0.993	0.0765
Carriage	0.076	0.988	0.0751
Chatfield Res.	**0.085**	0.9842	0.0837
Arvada	0.077	0.9949	0.0756
Welch	0.070	0.9863	0.0690
Rocky Flats North	**0.087**	0.9928	**0.0864**
NREL	**0.085**	0.9931	0.0844
Fort Collins	0.071	0.9991	0.0709
Greeley	---	---	
Weld County Tower	(0.082)	0.9876	0.0800
Rocky Mtn. N.P.	0.081	0.9872	0.0800

As can be noted attainment at all of the monitors is achieved (design values less than 0.085 ppm) in 2007 for the 8-hour ozone control area with the exception of Rocky Flats North (design value 0.0864 ppm), as a result of the reductions expected from existing programs and regulations. Additional control measures discussed in Chapter II have been applied to bring the Rocky Flats North monitor into attainment.

D. Weight of Evidence Analysis

EPA's 8-hour ozone modeling guidance suggests a weight of evidence attainment determination if the maximum modeled 8-hour ozone Design Value is between 0.084 ppm and 0.089 ppm at more than one monitor. EPA also allows for an attainment determination based on weight of evidence if the maximum, modeled 8-hour ozone Design Value is less than 90 ppb (0.090 ppm).

Results of corroboratory analyses may be used in a weight of evidence determination to conclude that attainment is likely despite modeled results which do not quite pass the attainment and/or screening tests. Such corroboratory analyses could include further analysis of modeling detail, emissions trends related to air quality, observation based models (NOx/VOC ratios), other corroborative evidence such as quantifying model uncertainties, considering other design value years, additional data collection, and possibly excluding episode days with ozone concentrations close to 0.070 ppm.

E. 2007 Control Case Emission Inventories

Reductions from control measures described in Chapter II have been applied to the 2007 base case emissions inventories as follows:

- Reid Vapor Pressure of base gasoline assumed to be 8.1 psi (maintains 1.0 psi waiver for ethanol-blended gasoline at 25% market share) – estimated 9 tpd VOC reduction to direct on-road mobile source emissions and 1 tpd VOC reduction in refueling (gas station) emissions.
- Flash emissions controls – estimated 55 tpd reduction in VOC
- Reciprocating internal combustion engine (RICE) controls – approximately 5.5 tpd VOC and 19 tpd NOx reduction
- Dehydrator controls – approximately 0.5 tpd VOC

The total emission reduction, compared to the 2002 base case, for these four control strategies (together with the federal and existing state controls assumed for the 2007 base case) is approximately 106 tons per day VOC and 58 tons per day NOx in the 8-county area (Denver metropolitan area plus Weld County). Emissions reductions associated with the application of these strategies to in Elbert, Larimer and Morgan counties have not been quantified and have not been included in the modeling. The resultant 2007 inventory based on the total RVP reduction plus Flash, RICE and Dehydrator control package noted above is presented in Tables 7a & 8a (VOC) for the 8-county area and 7b & 8b (NOx) for the11-county area below. As previously noted in

Chapter I all of the inventories presented represent a typical average episode day. In the modeling, all anthropogenic source categories can be varied by weekday, weekend day and/or hour of the day, and on-road mobile and biogenic sources are varied by differing meteorological conditions and diurnally varied by temperature.

Table 7a
VOC Emission Inventories
(tons per average episode day)
Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson and Weld Counties

Source Category	**2002 Base (tons/day)**	**2007 Base (tons/day)**	**2007 Control (tons/day)**	**2012 Maintenance (tons/day)**
Flash	133.9	146.1	91.3	100.9
Gas Stations	22.3	16.0	14.8	10.2
Oil and Gas Production	4.1	4.5	3.7	4.1
Reciprocating Internal Combustion Engines	7.8	8.7	4.8	5.4
Other Stationary Sources	24.6	28.8	28.7	28.9
Total Point	**192.8**	**204.1**	**143.3**	**149.5**
Automotive After Market Products	27.2	29.0	29.0	31.5
Architectural Coatings	19.5	20.8	20.8	22.6
Household and Personal Products	17.0	18.2	1 8.2	19.8
Adhesives and Sealants	14.7	15.7	15.7	17.1
Pesticide Application	8.9	10.0	10.0	11.5
Other Area Sources	9.6	10.4	10.4	11.6
Total Area	**96.9**	**104.1**	**104.1**	**114.0**
Lawn & Garden	47.3	31.2	31.0	26.7
Other Off-road	25.8	22.5	22.6	21.0
Total Off-road	**73.1**	**53.7**	**53.5**	**47.7**
Total On-road Mobile	**152.8**	**117.5**	**108.4**	**76.0**
Total Anthropogenic	**515.6**	**479.4**	**409.3**	**387.2**
Total Biogenic	468.1	468.1	468.1	468.1
Total	**983.7**	**947.5**	**877.4**	**855.3**

Note: Inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. The geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

Table 7b
VOC Emission Inventories
(tons per average episode day)
Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson and Weld Counties plus Larimer, Morgan and Elbert Counties

Source Category	**2002 Base (tons/day)**	**2007 Base (tons/day)**	**2007 Control (tons/day)**	**2012 Maintenance (tons/ day)**
Flash	134.3	147.2	92.0	101.7
Gas Stations	24.5	17.5	16.3	11.3
Oil and Gas Production	4.2	4.6	3.7	4.2
Reciprocating Internal Combustion Engines	9.0	9.9	6.0	6.7
Other Stationary Sources	28.0	30.1	28.8	29.0
Total Point	**200.0**	**209.3**	**146.7**	**152.8**
Automotive After Market Products	34.9	32.1	32.1	34.9
Architectural Coatings	25.0	23.0	23.0	25.0
Household and Personal Products	21.9	20.1	20.1	21.9
Adhesives and Sealants	18.9	17.4	17.4	18.9
Pesticide Application	15.0	13.1	13.1	15.0
Other Area Sources	15.5	14.0	14.0	15.6
Total Area	**131.2**	**119.6**	**119.6**	**131.3**
Lawn & Garden	38.3	35.0	34.7	30.0
Other Off-road	30.6	27.6	27.9	26.2
Total Off-road	**68.9**	**62.6**	**62.6**	**56.2**
Total On-road Mobile	**172.6**	**135.1**	**126.0**	**89.0**
Total Anthropogenic	**572.7**	**526.6**	**455.0**	**429.3**
Total Biogenic	799.5	799.5	799.5	799.5
Total	**1372.1**	**1326.1**	**1254.5**	**1228.8**

Note: Inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. The geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

Table 8a
NOx Emission Inventories
(tons per average episode day)
Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson and Weld Counties

Source Category	2002 Base (tons/day)	2007 Base (tons/day)	2007 Control (tons/day)	2012 Maintenance (tons/day)
Flash	0	0	0	0
Gas Stations	0.1	0.1	0.1	0.1
Oil and Gas Production	0.2	0.2	0.2	0.2
Reciprocating Internal Combustion Engines	93.5	94.7	75.8	82.8
Other Stationary Sources	11.4	12.2	12.2	12.2
Total Point	**105.2**	**107.1**	**88.3**	**95.3**
Automotive After Market Products	0	0	0	0
Architectural Coatings	0	0	0	0
Household and Personal Products	0	0	0	0
Adhesives and Sealants	0	0	0	0
Pesticide Application	0	0	0	0
Other Area Sources	25.60	27.6	27.6	31.1
Total Area	**25.60**	**27.6**	**27.6**	**31.1**
Lawn & Garden	9.31	9.3	9.4	9.3
Other Off-road	78.7	73.2	73.2	65.5
Total Off-road	**87.99**	**82.5**	**82.6**	**74.8**
Total On-road Mobile	**157.8**	**119.3**	**119**	**77.7**
Total Anthropogenic	**376.6**	**336.5**	**317.5**	**278.9**
Total Biogenic	37.1	37.1	37.1	37.1
Total	**413.7**	**373.6**	**354.6**	**316.0**

Note: Inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. The geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

Table 8b
NOx Emission Inventories
(tons per average episode day)
Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson and Weld Counties plus Larimer, Morgan and Elbert Counties

Source Category	2002 Base (tons/day)	2007 Base (tons/day)	2007 Control (tons/day)	2012 Maintenance (tons/day)
Flash	0.0	0.0	0.0	0.0
Gas Stations	0.1	0.1	0.1	0.1
Oil and Gas Production	0.2	0.2	0.2	0.2
Reciprocating Internal Combustion Engines	125.8	129.7	110.9	121.3
Other Stationary Sources	14.1	15.0	12.2	12.2
Total Point	**140.1**	**144.9**	**123.3**	**133.8**
Automotive After Market Products	0.0	0.0	0.0	0.0
Architectural Coatings	0.0	0.0	0.0	0.0
Household and Personal Products	0.0	0.0	0.0	0.0
Adhesives and Sealants	0.0	0.0	0.0	0.0
Pesticide Application	0.0	0.0	0.0	0.0
Other Area Sources	36.1	32.7	32.7	36.7
Total Area	**36.1**	**32.7**	**32.7**	**36.7**
Lawn & Garden	11.4	10.4	10.5	10.4
Other Off-road	91.6	82.1	82.8	74.1
Total Off-road	**103.0**	**92.4**	**93.3**	**84.6**
Total On-road Mobile	**177.6**	**136.6**	**136.3**	**90.1**
Total Anthropogenic	**456.7**	**406.6**	**385.6**	**345.1**
Total Biogenic	52.3	52.3	52.3	52.3
Total	**509.1**	**458.9**	**437.9**	**397.5**

Note: Inventories merely are a part of the technical basis for the attainment demonstration, and should not be construed to describe the scope of the plan. The geographic scope of the plan shall be determined by the final boundaries set by the U.S. EPA.

F. 2007 Control Case Demonstration

The four individual scenarios above have been modeled in CAMx as a SIP control strategy package. As discussed earlier in this Chapter III, the 2007 base case and 2007 SIP control case modeling produces relative reduction factors (RRF) for receptors in the modeling domain where ozone monitors are located.

As noted, the RRF is applied to the base case (2001-2003) design values for each monitor to calculate the 2007 control case design values based on the formula:

2007 Control Case Design Value = RRF * Base Case (2001-03 Design Value)

The RRF and the Design Value for each monitor resulting from the 2007 control case analysis are presented for the modeled days greater than 0.070 ppm and the modeled days greater than 0.080 ppm in the following table:

Table 9
2007 Control Case Design Values for Each Monitoring Site
for Modeled Days greater than 0.070 ppm
and Modeled Days greater than 0.080 ppm at Rocky Flats N.

		Days > 0.070 ppm at All Monitor Sites		Days > 0.080 ppm at Rocky Flat N. Site	
Site Name	**8-Hour Ozone Base Case Design Values 2001-2003 (ppm)**	**2007 Control Case RRF**	**2007 Control Case Design Values (ppm)**	**2007 Control Case RRF**	**2007 Control Case Design Values (ppm)**
Welby	0.066	0.9913	0.0654	1.0027	0.0661
Highland	0.081	0.9779	0.0792	0.9828	0.0796
S. Boulder Creek	0.077	0.9844	0.0758	0.9763	0.0751
Carriage	0.077	0.9805	0.0745	0.9773	0.0742
Chatfield Res.	**0.085**	0.9755	0.0829	0.9755	0.0829
Arvada	0.077	0.9875	0.0750	0.9847	0.0748
Welch	0.070	0.9784	0.0685	0.9747	0.0682
Rocky Flats North	**0.087**	0.9851	**0.0857**	0.9747	0.0849
NREL	**0.085**	0.9856	0.0838	0.9856	0.0828
Fort Collins	0.071	0.9884	0.0702	0.9795	0.0695
Greeley	---		-		-
Weld County Tower	(0.082)*	0.9782	0.0792	0.9788	0.0792
Rocky Mtn. N.P.	0.081	0.9740	0.0789	0.9721	0.0787

* Based on 2002 & 2003 data. Greeley monitor shut down 2001; Weld County Tower monitor started in 2002.

Attainment is demonstrated when the 2007 Control Case Design Value at each monitor is at 0.085 ppm or less.

As can be seen in the above Table 9, for all days greater than 0.070 ppm all of monitors achieve attainment with predicted design values below 0.085 ppm, except the Rocky

Flats North monitor. Considering days greater than 0.080 ppm, all monitors achieve attainment with predicted design values below 0.085 ppm including Rocky Flats North as a result of the 2007 control case analysis. In the next section, the weight of evidence determination provides more corroborating evidence and technical analysis beyond the dispersion modeling to support a conclusion that attainment is likely to occur.

G. Weight of Evidence Determination

EPA modeling guidance indicates that, if results of the modeling attainment demonstration is between 0.084 ppm and 0.089 ppm at more than one site, a weight of evidence (WOE) determination should be performed. As can be seen in the above Table 9, all other monitors have 2007 control case design values less than 0.084 ppm. Since the design value at the Rocky Flats North monitor is well below 0.090 ppm, the EPA guidance indicates that more corroborating evidence based on other analyses can be sufficiently convincing to support a conclusion that attainment is likely to occur despite the outcome of dispersion modeling tests.

As discussed by the modeling contractor, Environ (2004), the modeling results appear to be very stiff, that is, the estimated 8-hour ozone Design Values are not very sensitive to local emission controls. The reasons for this stiffness are as follows:

- Anomalous Meteorological Conditions in 2003 -The 2003 ozone season was noted for anomalous temperatures and mixing heights causing more conducive ozone forming meteorological conditions than are reflected in the June 2002 modeling episode. Thus the future design value is overestimated using the observed 2001-2004 design value, and the local control strategies applied are not as effective using the June 2002 modeling episode.
- Under Prediction Tendency of Model - Although the model achieved most of EPA's performance goals, it exhibited a general under prediction tendency so that less ozone was likely attributable to the local emissions than likely occurred in actuality.

Weight Of Evidence Analyses

- **Anomalous Meteorological Conditions in 2003**

  Meteorological data is provided in the Technical Support Document (TSD) Appendix O - Weight of Evidence – Inter-Office Memorandum, Reddy February 9, 2004 that demonstrates that lower than average mixing heights and record setting maximum temperatures occurred in 2003.

Trend analysis using the 4th maximum concentration at Rocky Flats North, and the Zurbenko-Rao Decomposition Method demonstrates that irrespective of temperature (and all weather effects for which temperature is a good surrogate) ozone concentrations will trend below the 8-hour ozone standard in future years - TSD Appendix O - Weight of Evidence – Inter-Office Memorandum, Reddy, February 9, 2004

- **Under Prediction Tendency of Model**

Under prediction of the model by approximately 20% is well documented in the 2002 model performance evaluation report. TSD Appendix H.

An analysis of the use of modeled days greater than 70 ppb and modeled days greater than 80 ppb in Table 10 below indicates the stiffness in the modeled data for the days greater than 70 ppb from June 27 through June 30. Only the July 1 episode day has modeled values greater than 70 ppb across the entire monitoring network. Only the July episode day with an estimated 8-hour ozone concentration of 85 ppb is close to both the Design Value (87 ppb) and the observed value on this day (89 ppb). TSD Appendices B, K & L

Analysis of modeled episode days greater than 80 ppb in Table 9 previously presented indicates all monitors for the 2007 control case are below 0.085 ppm, including the Rocky Flat North monitor, demonstrating that on a day that the modeled performed closer to the Design Value and the observed value, the local control strategies were more effective and sufficient to support the conclusion of attainment. TSD Appendix L

Back Trajectory analyses prepared by the APCD and Environ indicate that local emissions contribute to the high ozone concentrations at the Rocky Flats monitor during this episode. Appendices L & O

The Ozone Source Apportionment Technique modeling is completed but final analysis is not. The analysis will provide contribution of emissions by geographical regions, sub-regions and major source category, thus aiding in establishing the adequacy of the proposed control package for all episode days. TSD Appendices M & O.

Table 10
Modeled 2002 Base Case and 2007 Control Case (ppb)

2002 Base Case: run11a		**25-Jun**	**26-Jun**	**27-Jun**	**28-Jun**	**29-Jun**	**30-Jun**	**1-Jul**		
Site	DV	02176	02177	02178	02179	02180	02181	02182	#Days>70	#Days>80
Weld County Tow	81	61	57.2	65.2	60.6	69.4	66.9	**70.9**	1	
Rocky Mtn. NP	81	63.1	64.3	67.4	62	**71.4**	**76**	**79.1**	3	
Fort Collins	71	63.2	62.6	69.5	59	65.4	**70.7**	**73.5**	2	
USAF Academy	73	56.6	63.5	56.6	66.6	61	69.4	**70.6**	1	
Welch	70	58.9	66.5	69.8	**71.7**	65.7	**73**	**87.2**	3	1
Rocky Flats Nor	87	62.8	62.7	**70.9**	62.1	**70.5**	**73.8**	**84.5**	4	1
NREL	85	60.4	64.6	**70.9**	64.9	63.1	**73.8**	**87.2**	3	1
Arvada	76	59.8	60	**70.8**	63.1	69.1	**71.8**	**85.1**	3	1
Welby	66	56.6	55.2	62.6	66.5	**70**	66.2	**72.7**	2	
S. Boulder Creek	77	63	62.8	**70.9**	63	**70.9**	**74.1**	**84.5**	4	1
Carriage	76	58.4	62.3	68.8	67.9	66.6	**71.9**	**83.8**	2	1
Highland	81	57.4	66.3	62.7	**73**	69.7	**71.9**	**81.6**	3	1
Chatfield Res.	85	57.9	66.5	63.4	**73**	69.7	**71.9**	**85.9**	3	1

2007 Future Year control case: 07run11a.a1-attn

Site	DV	02176	02177	02178	02179	02180	02181	02182
Weld County Tow	81	59.4	56	63.8	58.9	67.1	66	**69.4**
Rocky Mtn. NP	81	63.3	62.6	65.7	60.7	**69.6**	**74.2**	**76.9**
Fort Collins	71	62.3	61.3	67.9	58.1	63.8	**70.5**	**72**
USAF Academy	73	56.2	62.4	55.8	64.6	59.5	67.9	**68.3**
Welch	70	58.7	66.5	68.7	**70**	64.6	**72**	**85**
Rocky Flats Nor	87	63.6	61.6	**70**	61.1	**69.1**	**73.5**	**82.5**
NREL	85	60.3	65.3	**70**	64.9	62.1	**73.5**	**85**
Arvada	76	60	60.5	**70**	61.5	67.8	**71**	**83.8**
Welby	66	56.1	54.5	63.5	64.5	68.6	67.5	**72.9**
S. Boulder Creek	77	64	61.7	**70**	61.8	69.6	**73.5**	**82.5**
Carriage	76	59	63.8	68.7	67.5	66.1	**70.7**	**81.9**
Highland	81	56.9	66.1	62.9	**70.7**	67.3	**70.6**	**80.2**
Chatfield Res.	85	57.8	66.2	61.6	**70.7**	67.3	**70.7**	**83.8**

- **Additional Model Metrics**

  # Grid-Hours > 84 ppb: The relative change from the 2002 base case to the 2007 control case in the number of grid cell – hours during the modeling episode in which the estimated 8-hour ozone concentrations are greater than 84 ppb is calculated to be 85%, which is over the "large" reduction (80%) suggested by EPA to be consistent with a conclusion that the proposed control strategy package meets the 8-hour standard. TSD Appendix H

Relative Difference (RD): The Relative Difference (RD) in 8-Hour ozone concentrations greater than 84 ppb computed as the ratio of the average of estimated excess 8-hour ozone above 84 ppb of the future-year simulation to the base-year base case is calculated at 94% further supporting the conclusion that the proposed control strategy package meets the 8-hour standard. TSD Appendix H

VOC-NOX Sensitivity: Sensitivity model runs looking at reduction of VOC, NOx and VOC and NOx indicate that VOC reductions are more important to reductions in ozone at the critical monitor than NOx reductions confirming the validity of the proposed control package focusing on VOC reductions. TSD Appendix K

- **Additional Analyses**

Monitored Speciation Data: Recent ambient monitored precursor data indicates similarity between ambient data and emissions estimates. Very close correlation between flash emissions speciation data and ambient measurements in Weld County the source of almost all of the Flash emission in the inventory. TSD Appendix C & N

Ambient Monitoring & Emissions Trends: Monitored trends and emissions trends of CO and PM10 and emissions trends are declining supporting the concept that over all air quality is improving due to controls in place in the region. TSD Appendix C

Design Value and Emissions Trends: Analysis of 3-year period design values for 8-hour ozone and precursor emissions indicates that both are trending down. TSD Appendix C

PBL Height and Boundary Condition Analysis: Modeling of the 2002 base case investigated the impacts of changes in PBL Heights and Boundary conditions to maximize appropriate assumptions in future modeling. TSD Appendix G & H

H. 2012 Maintenance Year Emission Inventory and Maintenance Demonstration

EPA's Early Action Compact Protocol guidance requires that areas demonstrate long-term maintenance of the 8-hour ozone NAAQS through the year 2012. Although photochemical modeling analysis is required for the 2007 attainment demonstration, a simple comparison of emission inventories is sufficient to demonstrate maintenance. For this plan, the 2007 control case emission inventory, which is supported by a weight of evidence determination of attainment, is compared with the 2012 inventory. When total emissions in 2012 are less than total emissions in 2007 that are supported by a determination of attainment, continued maintenance is demonstrated. The 2012 inventories assume that the 2007 control measures remain in place throughout the maintenance period through 2012. The 2012 inventory also accounts for federal emission control measures taking effect from 2007 through 2012.

The 2007 control case inventories for the 8 county area and the 11 county area and the 2012 maintenance inventories are presented previously in Tables 7a & 7b and 8a & 8b.

NEWS

Oil, gas industry may face tougher air pollution rules

By **THE ASSOCIATED PRESS**
April 10, 2008 at 11:57 a.m.

DENVER—The Colorado oil and gas industry could face tougher air pollution regulations as the Front Range, including Denver, tries to meet stricter federal ozone standards.

The state tightened standards on the oil and gas industry in late 2006 to reduce ground-level ozone levels to meet federal requirements. Regulators said pollution from oil and gas production has increased with expanded drilling in northern Colorado while emissions from other sources have declined.

Last November's announcement that the Denver area is in violation of federal ozone limits and the subsequent decision to strengthen standards nationwide have prompted Colorado to clamp down even more.

Ground-level ozone, a key component of smog, is created when the sun bakes pollutants such as vehicle exhaust, wildfire smoke and vapors from everything from paint cans to oil and gas wells.

The state must come up with short- and long-term ways to cut ozone levels, said Mike Silverstein, manager of planning and policy for the state air pollution control division.

Silverstein said during a Regional Air Quality Council meeting Thursday that the state is proposing stronger controls on tanks at natural gas wells that store liquids and other byproducts.

The other recommendation pared from a list of more than 10 is installing pneumatic devices, used to control gas and liquid flows, that emit fewer natural gas vapors.

The plan is to take comments from the industry, local regulators and environmental groups and present proposals to the regional and state air quality panels by late summer.

"We feel these are the most effective strategies," Silverstein said.

The proposals would apply just to the nine-county area stretching from Douglas County, south of Denver, to Larimer County, north of the Denver area. It includes Weld County, northeast of Denver, which has nearly 12,900 active oil and gas wells, the most in the state.

Members of a coalition of environmental groups and local governments suggested that regulators consider pollution controls for other gas-field equipment, including some of the engines and dehydrators.

Industry representatives have argued that oil and gas companies are being unfairly singled out as the Front Range struggles to comply with federal ozone levels.

Regulations adopted in 2006 required oil and gas companies in northeastern Colorado to cut emissions by 75 percent, more stringent than the former standard of 47.5 percent. The state air quality control commission also imposed the first-ever statewide pollution controls on oil and gas operations because of the growing number of wells there.

Natural gas production was considered the likely source of high ozone levels in February in western Wyoming that spawned the state's first-ever ozone warnings.

Ozone is a colorless gas that is health treat to children and people with respiratory problems.

——————

Colorado Department of Public Health and Environment Ozone Reduction Efforts:

http://www.cdphe.state.co.us/ap/ozone.html

FOR IMMEDIATE RELEASE: Dec. 20, 2019

Air Quality Control Commission approves first phase of rules to reduce oil and gas emissions

DENVER: The Colorado Air Quality Control Commission approved the first set of ambitious rules designed to minimize emissions from oil and gas operations state-wide yesterday. The rules will help reduce ozone pollution and protect the health of Coloradans and the air they breathe.

“Yesterday was a milestone, and we are already looking ahead to achieve further reductions of emissions at oil and gas sites through our next rulemaking. The department intends to build on this momentum,” **said Jill Hunsaker Ryan**, executive director of the Colorado Department of Public Health and Environment.

The commission’s Thursday vote came after a thorough rulemaking process in which the Air Pollution Control Division worked closely with local governments, the public, and other stakeholders to craft new rules that meet the needs of Colorado’s diverse communities. In addition, the Commission held meetings in Rifle, Durango, and Loveland at which commission members heard hundreds of comments from the public.

The rules approved by the Commission on Thursday include:

- Eliminating the existing 90-day permitting deferral on new oil and gas facilities - under the new rule, these facilities must be permitted before they can begin exploration and production activities.
- Requiring at least twice-a-year leak detection and repair at well production facilities throughout the state with volatile organic chemical (VOC) emissions of greater than two tons per year.
    - Requiring either quarterly or monthly leak detection, depending on the size of the facility, at sites within a 1000 feet of occupied structures.
- Requiring oil and gas operators to provide a comprehensive annual emissions report for oil and gas facilities.
- Further reducing emissions of VOCs and from storage tanks by setting more stringent control requirements across the state.
- Requiring new oil and gas facilities to control hydrocarbon emissions from sampling and measurement activities and from the loadout of storage tanks to trucks.
- Enhancing recordkeeping requirements for emissions at wells across the state.
- Expanding new inspection requirements - currently in place within the ozone nonattainment area - for pressure valves or “pneumatic controllers” at oil and gas sites across the state.

The division estimates that the new rules will reduce methane and volatile organic compound emissions by thousands of tons a year.

“The objective is simple-- minimize emissions at the source,” **said Ga**

Pollution Control Division. “These new rules represent months of hard work and communication with affected communities. They will slash emissions, make Colorado’s air cleaner and improve the quality of life for Coloradans across the state, including those citizens that live or work near oil and gas sites. They’re reasonable, cost effective, innovative, and absolutely necessary. And we’re just getting started.”

###

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DEQ confirms ozone pollution violated federal standards

The agency said it will work with the federal EPA — not cede local control — to clean up the air in the Upper Green River Basin

June 18, 2019 by Angus M. Thuermer Jr. — 1 Comment

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Sublette County residents earlier this year complained of ozone pollution at some of the five DEQ monitoring sites in the basin. Preliminary readings from monitors, information that DEQ provides instantly at its website, showed 10 days during which ozone levels exceeded federal Clean Air Act standards.

DEQ has validated those preliminary readings, an agency spokesman told WyoFile earlier this month. The confirmations include nine days at Boulder and one at Daniel when ozone levels exceeded the federal standard of 70 parts per billion.

Readings are calibrated in rolling eight-hour averages. Federal standards for that measure were strengthened in 2015 from 75 ppb to 70 ppb "to ensure the protection of public health and welfare," the federal Environmental Protection Agency said.

The highest ozone reading at Boulder registered 105 ppb, a level the state classifies as "unhealthy" and at which "everyone may begin to experience health effects," the DEQ website reads. Levels of 106 ppb are "very unhealthy."

DEQ director Todd Parfitt briefed lawmakers last month about the worrisome events.

"We were quickly approaching the most detrimental category for ozone concentration," he told members of the Joint Minerals, Business and Economic Development Committee at meeting in Gillette in May. "We were looking at taking even more drastic measures than what had been taken."

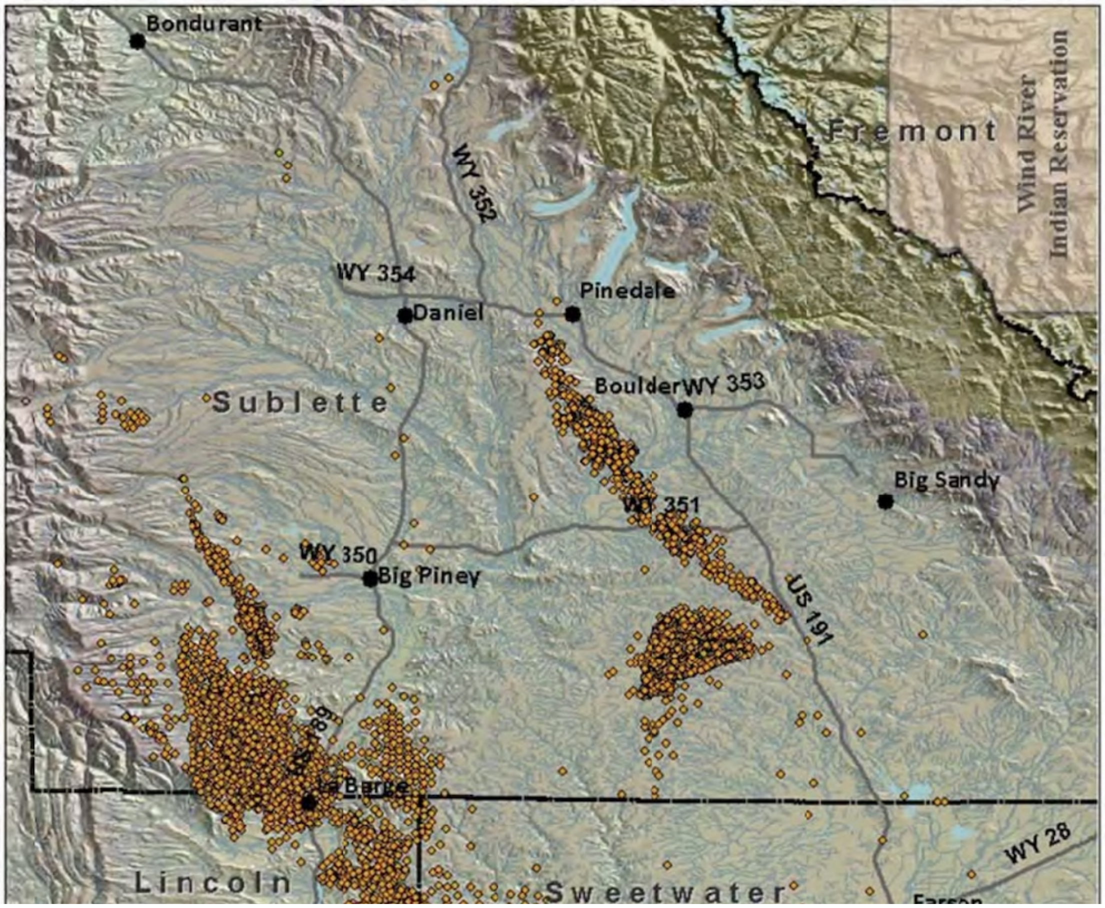
Pollution watchdogs believe the 2019 measures, when coupled with the previous years' readings, would put the Upper Green River Basin back into a federal "non-attainment" category for exceeding Clean Air Act limits over a three-year period.

"It's above the maximum," said Elaine Crumpley, a founding member of the Pinedale-based group Citizens United for Responsible Energy Development. "We're not meeting the Clean Air Act, I suspect."

Despite the best efforts?

The pollution occurred despite what the state called a "success" last winter with its Ozone Contingency Plan Program. Twenty-five oil and gas companies operating in the area submitted ozone action plans for the winter, according to a summary contained in a letter sent by the DEQ to program participants.

low temperatures in the basin.



Oil and gas companies have drilled thousands of wells in and near Sublette County as depicted in this map created in 2010. (Wyoming DEQ, Department of Health)

DEQ called for 16 ozone action days in the first three months of 2019 — the winter ozone forecasting season. “On average, 89% of participants with [ozone contingency plans] submitted Event Summaries after each event,” the DEQ letter said. “This program was a continued success due to the support and immense effort put forth to implement emission-reducing efforts on sixteen OADs.”

An average of 20 companies briefed workers before their shifts and minimized the idling of vehicles, the letter said. An average of 19 companies alerted all personnel and staff of the action days and contingency plans, avoided overfilling fuel tanks and tightened fuel tank caps.

The federal Environmental Protection Agency in 2012 classified the area as a “marginal” ozone non-attainment zone after ozone levels violated federal ozone air quality standards of 75 ppb. In response

The group bases that assertion on a formula that averages the fourth-highest reading from the last three years. Those readings are 73 in 2017, 58 in 2018 and 85 in 2019, watchdogs said.

“When you average that, it’s 72 and the maximum is 70,” Crumpley said. DEQ hasn’t said whether it believes the measurements put the state back into the non-attainment category, or what that would mean if the Upper Green River Basin was again so designated.

Part of the complication arises from the strengthening of air-quality standards in 2015 to 70 ppb. It’s debated whether that, or the less-restrictive 75 ppb — when the Upper Green River Basin non-attainment area was mapped and classified — should apply.

“Statistically it’s there,” Crumpley said of a non-attainment measure.

The Wyoming Outdoor Council is also waiting for action. “I’ve not heard DEQ explain how this is going to change the requirements in the area or in a more narrowed area to ensure that the Boulder area gets back into attainment with ozone … to ensure we get below that 70 ppb,” Steff Kessler, program director with the conservation group, told WyoFile.

The lowdown coming

DEQ is scheduled to meet with area residents in Boulder on June 26 to review last winter’s ozone pollution events and answer questions. The meeting is set for 6 p.m. at the Boulder Community Center.

“They’re going to give us the lowdown [as] to what they decided,” Crumpley said.

DEQ spokesman Keith Guille agreed. “Obviously we’ll be answering any concerns the public has,” he said.

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Despite the two standards — one from before and one from after 2015 — “we always want to have [ozone pollution levels] under 70,” he said. That’s what we’ve set and that’s what we’ll continue to strive for.

Just because Wyoming exceeded a limit doesn’t mean the EPA will swoop in, take over programs and impose restrictions on activities, Guille said.

“We’re the ones with primacy with air quality and [the] airshed ,” he said. “There’s a process — we’ll work with EPA.”

A lot of states have areas that are in non-attainment status and haven’t lost primacy, also known as home-rule enforcement of federal standards.

“Our state was a leader and has been a leader on air emissions on minor sources,” Guille said. “We have probably the most stringent standards across the country.”

Nevertheless, “this area is a challenge,” he said. “We’ve been able to reduce emissions a lot. Obviously, it’s not done and we have a lot more to do.”

Guille was echoing what Parfitt told lawmakers in Gillette. “This is a high priority for the agency,” he said.

Pollution from ponds?

There's one source of volatile organic compounds that has flummoxed DEQ, Guille said — commercial oilfield waste ponds. They store produced water and other fluids that are a byproduct of oil and gas field production.

"There are no [air-quality] permits," Guille said. "They're just not regulated in any way," for those emissions.

Some basin residents have pointed to a pond near Boulder as a potential source of the volatile organic compounds that are ozone precursors. DEQ's air quality division, along with a team of contractors, has been working with disposal companies R360 Environmental Solutions, LLC and Anticline Disposal, Inc. to measure air emissions at the LaBarge and Pinedale facilities.

The goal is to develop a tool or model that would allow regulators to determine what volatile organic compounds such ponds emit, Guille said. DEQ would take water samples, plug measurements of their composition into a computer model or program and determine what emissions that water might produce, he said.

"That's taking some work," he said. A summary from several years' study indicates that the model or tool produces poor results.

"Upon conclusion of this study, the tool's accuracy in predicting emissions remains as much as an order of magnitude in under- or over-predicting individual air emission measurements," a summary reads. The variations depend on the volatile organic compounds in question, the season and weather.

"Obviously something's still not right," Crumpley said. "These are emissions that no one's catching. That anticline disposal pit needs to be reworked, covered."

The state has two persons and two forward-looking infrared cameras — essentially leak detectors — to inspect 7,500 wells, she said.

"That's crazy," Crumpley said. "We need more people with better equipment to detect these escaping emissions."

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Crumpley doesn't seek federal intervention, just state action.

"I want them to be able to handle it at the state level with what they are charged to do," she said. "It's getting old," she said of the ongoing pollution. "It's not a mystery."

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About Angus M. Thuermer Jr.

Angus M. Thuermer Jr. is the natural resources reporter for WyoFile. He is a veteran Wyoming reporter and editor with more than 35 years experience in Wyoming. Contact him at angus@wyofile.com or (307) 690-5586. Follow Angus on Twitter at @AngusThuermer

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Northern Wasatch Front, Southern Wasatch Front, and Uinta Basin

Final Area Designations for the 2015 Ozone National Ambient Air Quality Standards Technical Support Document (TSD)

1.0 Summary

This technical support document (TSD) describes the EPA's final designations for the Northern Wasatch Front, Southern Wasatch Front, and Uinta Basin in Utah as nonattainment for the 2015 ozone National Ambient Air Quality Standards (NAAQS).

On October 1, 2015, the EPA promulgated revised primary and secondary ozone NAAQS (80 FR 65292; October 26, 2015). The EPA strengthened both standards to a level of 0.070 parts per million (ppm). In accordance with Section 107(d) of the Clean Air Act (CAA), whenever the EPA establishes a new or revised NAAQS, the EPA must promulgate designations for all areas of the country for that NAAQS.

Under section 107(d), states were required to submit area designation recommendations to the EPA for the 2015 ozone NAAQS no later than 1 year following promulgation of the standards, i.e., by October 1, 2016.

On September 29, 2016, the State of Utah made designation recommendations for counties in Utah based on air quality data from 2013-2015. The State recommended that Salt Lake and Davis counties, and portions of Weber and Tooele Counties be designated as nonattainment for the 2015 ozone NAAQS. The State also recommended a designation of nonattainment for a portion of Utah County. Additionally, the State of Utah recommended a designation of nonattainment for townships in the counties of Duchesne and Uintah under state air jurisdiction, that are at and below the 6,000-ft elevation.

Tribes were also invited to submit area designation recommendations. On September 27, 2016, the Ute Indian Tribe of the Uintah and Ouray Reservation recommended that the area of tribal land at an unspecified distance around the Ouray ozone monitor in the Uinta Basin be designated as nonattainment for the 2015 ozone NAAQS based on air quality data from 2013-2015. However, the Tribe also recommended that if the EPA concurs on an exceptional event package submitted for two days in June 2015, the Tribe recommends attainment for all tribal land in the Uinta Basin. After considering these recommendations and based on the EPA's technical analysis as described in this TSD, the EPA is designating the areas listed in Table 1 as nonattainment for the 2015 ozone NAAQS. The EPA must designate an area nonattainment if it has an air quality monitor that is violating the standard or if it has sources of emissions that are contributing to a violation of the NAAQS in a nearby area. Detailed descriptions of the final nonattainment boundaries for these areas are found in the supporting technical analysis for each area in Section 3.

Table 1. Utah's Recommended Nonattainment Areas and the EPA's Final Nonattainment Areas for the 2015 Ozone NAAQS

Area	Utah's Recommended Nonattainment Counties	Utah's Updated Recommended Nonattainment Counties	EPA's Final Nonattainment Counties
Northern Wasatch Front, Utah	Salt Lake County Davis County Weber County (partial) Tooele County (partial)	Salt Lake County Davis County Weber County (partial) Tooele County (partial)	Salt Lake County Davis County Weber County (partial) Tooele County (partial)
Southern Wasatch Front, Utah	Utah County (partial)	Utah County (partial)	Utah County (partial)
Uinta Basin*	Duchesne and Uintah Counties (both partial); Townships with >10% of land mass below 6,000 feet.	Duchesne and Uintah Counties (both partial); Finest boundary resolution possible: quarter-quarter sections or elevation contour boundary.	Duchesne and Uintah Counties (both partial); elevation contour boundary at 6,250 feet.

*Uinta Basin is a multi-jurisdictional nonattainment area that includes areas of Indian country of Federally-recognized tribes. The areas of Indian country that the EPA is designating part of the nonattainment area are discussed in Section 3.2, Technical Analysis for the Uinta Basin. The Ute Tribe recommended an unspecified nonattainment boundary around the Ouray monitor in Uintah County. The EPA's final nonattainment area for the Uinta Basin includes both state and tribal land within the specified boundary.

In their letter, Utah recommended that the EPA designate as "attainment" or "unclassifiable/attainment" all other counties and partial counties not identified in the State's Recommended Nonattainment Counties column of Table 1. On November 6, 2017 (82 FR 54232; November 16, 2017), the EPA signed a final rule designating eleven counties (Beaver, Emery, Garfield, Iron, Kane, Millard, Piute, San Juan, Sevier, Washington, and Wayne) in the southern half of the State as attainment/unclassifiable for the 2015 ozone NAAQS. The EPA explains in section 2.0 the approach it is now taking to designate the remaining areas in the State.

The EPA is not modifying the State's recommendation for the Northern and Southern Wasatch Front nonattainment areas. However, the EPA is modifying the State's recommendations for the Uinta Basin Area. Utah's initial recommendation was to include all townships with greater than 10% of land less than 6,000 feet in elevation. In the 120-day letter to the state, the EPA intended to modify the State's recommendation to include all townships with greater than 10% of land mass below 6,250 ft. In the February 26th letter to the EPA, Utah recommended that the EPA use "the finest resolution boundary possible, whether that is elevation or quarter-quarter sections". The EPA also disagrees with the Tribe's recommendation, and the EPA is designating the Tribal area within parts of Uintah County and Duchesne County as nonattainment based on ambient monitoring data collected at Tribal monitors during the 2014-2016 period, where available, showing non-compliance with the 2015 ozone NAAQS. Although the EPA has approved the Tribe's exceptional events demonstration, three monitors included in the demonstration are still showing violations of the 2015 NAAQS, as discussed further in Section 3 – Factor 1.

The EPA will designate all tribal area in accordance with two guidance documents issued in December 2011 by the EPA Office of Air Quality Planning and Standards titled, "Guidance to Regions for Working with Tribes during the National Ambient Air Quality Standards (NAAQS)) Designations Process,"[1] and "Policy for Establishing Separate Air Quality Designations for Areas of Indian Country."[2]

2.0 Nonattainment Area Analyses and Final Boundary Determination

The EPA evaluated and determined the final boundaries for each nonattainment area on a case-by-case basis, considering the specific facts and circumstances of the area. In accordance with the CAA section 107(d), the EPA is designating as nonattainment the areas with monitors that are violating the 2015 ozone NAAQS and nearby areas with emissions sources (i.e., stationary, mobile, and/or area sources) that contribute to the violations. As described in the EPA's designations guidance for the 2015 NAAQS (hereafter referred to as the "ozone designations guidance"),[3] after identifying each monitor indicating a violation of the ozone NAAQS in an area, the EPA analyzed those nearby areas with emissions potentially contributing to the violating area. The EPA believes that using the Core Based Statistical Area (CBSA) or Combined Statistical Area (CSA)[4] as a starting point for the contribution analysis is a reasonable approach to ensure that the nearby areas most likely to contribute to a violating area are evaluated. The area-specific analyses may support nonattainment boundaries that are smaller or larger than the CBSA or CSA. The EPA's analytical approach is described in Section 3 of this technical support document.

On November 6, 2017, the EPA issued attainment/unclassifiable designations for approximately 85% of the United States and one unclassifiable area designation.[5] At that time, consistent with statements in the designations guidance regarding the scope of the area the EPA would analyze in determining nonattainment boundaries, EPA deferred designation for any counties in the larger of a CSA or CBSA where one or more counties in the CSA or CBSA was violating the standard and any counties with a violating monitor not located in a CSA or CBSA. In addition, the EPA deferred designation for any other counties adjacent to a county with a violating monitor. The EPA also deferred designation for any county that had incomplete monitoring data, any county in the larger of the CSA or CBSA where such a county was located, and any county located adjacent to a county with incomplete monitoring data.

The EPA is proceeding to complete the remaining designations consistent with the designations guidance (and EPA's past practice) regarding the scope of the area the EPA would analyze in determining

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[1] https://www.epa.gov/sites/production/files/2016-02/documents/ozone-designation-tribes.pdf

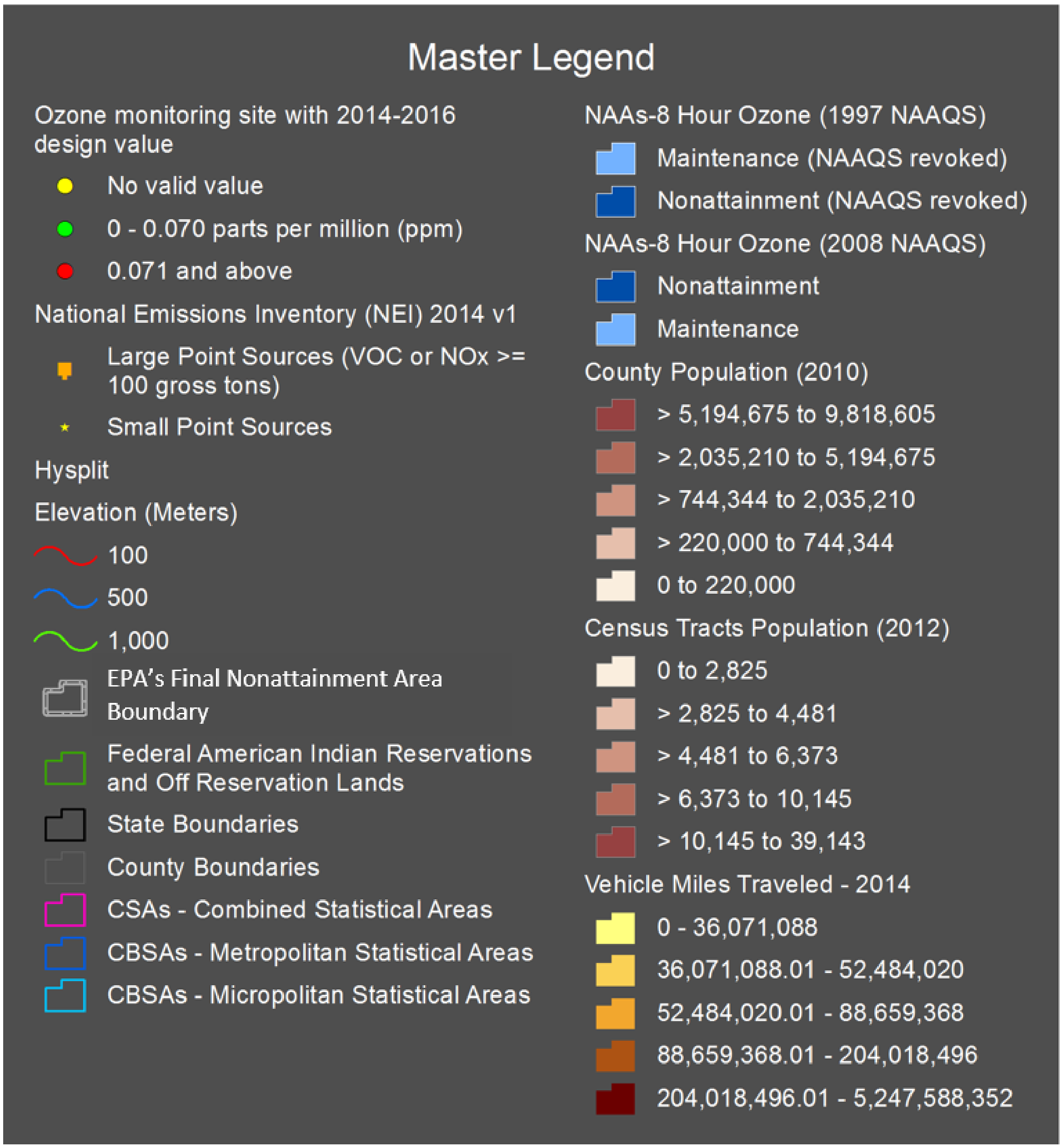
[2] https://www.epa.gov/sites/production/files/2016-02/documents/indian-country-separate-area.pdf

[3] The EPA issued guidance on February 25, 2016 that identified important factors that the EPA intends to evaluate in determining appropriate area designations and nonattainment boundaries for the 2015 ozone NAAQS. Available at *https://www.epa.gov/ozone-designations/epa-guidance-area-designations-2015-ozone-naaqs*

[4] Lists of CBSAs and CSAs and their geographic components are provided at www.census.gov/population/www/metroareas/metrodef.html. The Office of Management and Budget (OMB) adopts standards for defining statistical areas. The statistical areas are delineated based on U.S. Census Bureau data. The lists are periodically updated by the OMB. The EPA used the most recent July 2015 update (OMB Bulletin No. 15-01), which is based on application of the 2010 OMB standards to the 2010 Census, 2006-2010 American Community Survey, as well as 2013 Population Estimates Program data.

[5] Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards published on November 16, 2017(82 FR 54232).

nonattainment boundaries for the ozone NAAQS as outlined above. For those deferred areas where one or more counties violating the ozone NAAQS or with incomplete data are located in a CSA or CBSA, in most cases the technical analysis for the nonattainment area includes any counties in the larger of the relevant CSA or CBSA. For counties with a violating monitor not located in a CSA or CBSA, the EPA explains in the 3.0 Technical Analysis section, its decision whether to consider in the five-factor analysis for each area any other adjacent counties for which the EPA previously deferred action. We are designating all counties not included in five-factor analyses for a specific nonattainment or unclassifiable area analyses, as attainment/unclassifiable. These deferred areas are identified in a separate document entitled "Designations for Deferred Counties and County Equivalents Not Addressed in the Technical Analyses." which is available in the docket.



Figures in the remainder of the document refer to the master legend above

3.0 Technical Analyses for Final Nonattainment Areas

3.1 Technical Analysis for Northern Wasatch Front and Southern Wasatch Front Areas

This technical analysis identifies the areas with monitors that violate the 2015 ozone NAAQS. It also provides EPA's evaluation of these areas and any nearby areas to determine whether those nearby areas have emissions sources that potentially contribute to ambient ozone concentrations at the violating monitors in the area, based on the weight-of-evidence of the five factors recommended in the EPA's ozone designations guidance and any other relevant information. In developing this technical analysis, the EPA used the latest data and information available to the EPA (and to the states and tribes through the Ozone Designations Mapping Tool and the EPA Ozone Designations Guidance and Data web page).[6] In addition, the EPA considered any additional data or information provided to the EPA by states or tribes.

The area of analysis for the Northern Wasatch Front and Southern Wasatch Front areas is the Salt Lake City-Provo-Orem CSA. The CSA is comprised of three Metropolitan Statistical Areas (MSAs) and two Micropolitan Statistical Areas. Because of the size of the counties involved, the Salt Lake City-Provo-Orem CSA is a very large analysis area. It is about the size of the State of West Virginia, and larger than nine other states. The counties that are included in these areas are as follows:

- Ogden-Clearfield MSA: Box Elder County, Davis County, Morgan County, Weber County
- Salt Lake City MSA: Salt Lake County, Tooele County
- Provo-Orem MSA: Juab County, Utah County
- Summit Park Micropolitan Statistical Area: Summit County
- Heber Micropolitan Statistical Area: Wasatch County

The five factors recommended in the EPA's guidance are:

1. Air Quality Data (including the design value calculated for each Federal Reference Method (FRM) or Federal Equivalent Method (FEM) monitor;
2. Emissions and Emissions-Related Data (including locations of sources, population, amount of emissions, and urban growth patterns);
3. Meteorology (weather/transport patterns);
4. Geography/Topography (including mountain ranges or other physical features that may influence the fate and transport of emissions and ozone concentrations); and
5. Jurisdictional Boundaries (e.g., counties, air districts, existing nonattainment areas, areas of Indian country, Metropolitan Planning Organizations (MPOs)).

Figure 1 is a map of the EPA's final nonattainment boundaries for the Northern Wasatch Front and Southern Wasatch Front areas. The map shows the location of the ambient air quality monitors, county, and other jurisdictional boundaries.

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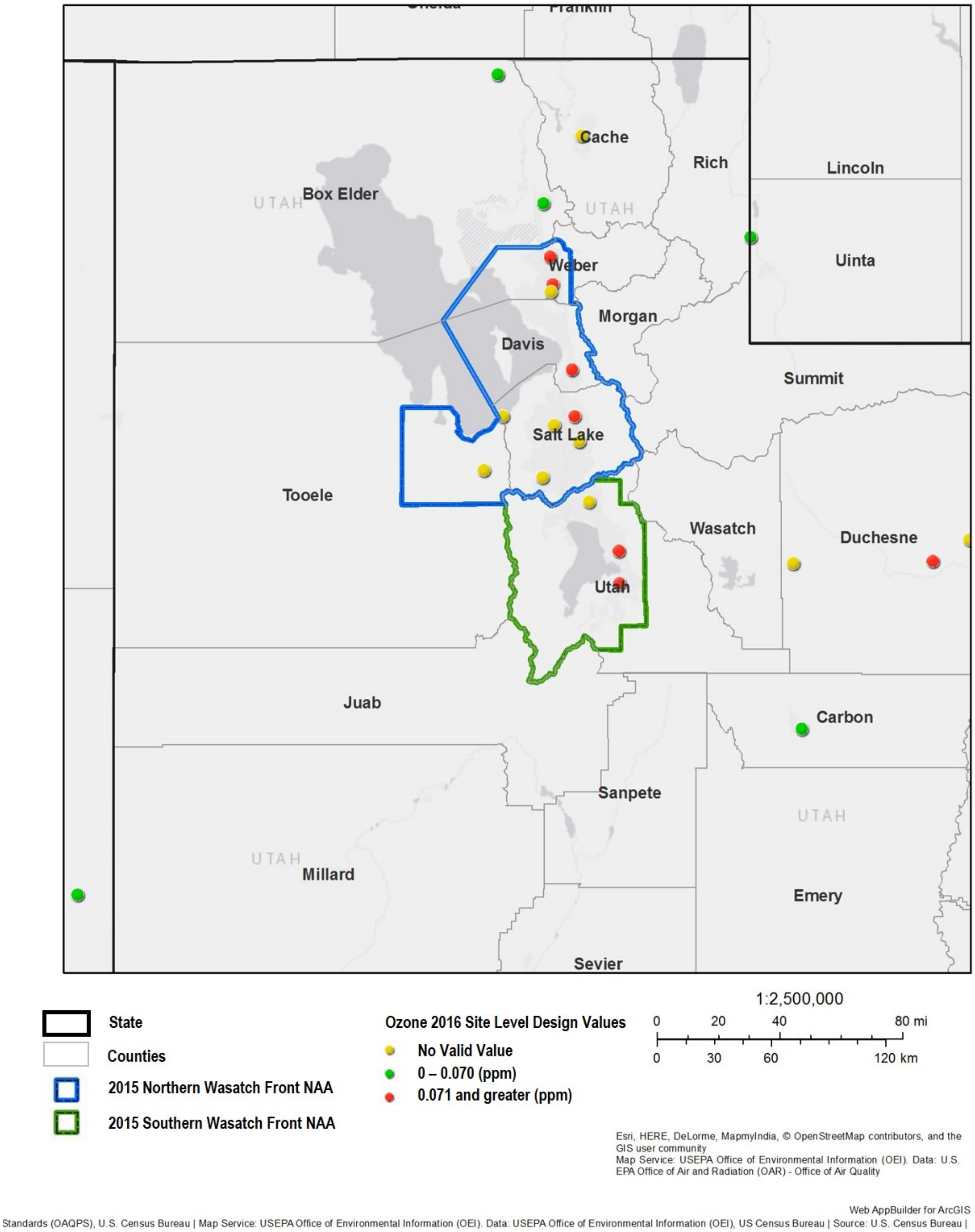
[6] The EPA's Ozone Designations Guidance and Data web page can be found at *https://www.epa.gov/ozone-designations/ozone-designations-guidance-and-data*.

Figure 1. EPA's Final Nonattainment Boundaries for the Northern Wasatch Front and Southern Wasatch Front Areas



The State recommended that EPA designate two separate nonattainment areas for counties in this CSA – the Northern Wasatch Front and the Southern Wasatch Front. The EPA is analyzing all of the counties in the

CSA together in this TSD, but, as provided in the conclusion, the EPA is not modifying the State's recommendation to designate two separate nonattainment areas.

The EPA must designate as nonattainment any area that violates the NAAQS and any nearby areas that contribute to the violation in the violating area. Davis, Salt Lake, Utah, and Weber Counties have monitors in violation of the 2015 ozone NAAQS, therefore these counties (or portions of these counties) are included in the final nonattainment areas. Based on the analysis that follows, the EPA determined that portions of Tooele County contribute to violations of the NAAQS in the area. The following sections describe the five factor analysis supporting the final designations for the Northern and Southern Wasatch Front areas. While the factors are presented individually, they are not independent. The five factor analysis process carefully considers the interconnections among the different factors and the dependence of each factor on one or more of the others, such as the interaction between emissions and meteorology for the area being evaluated.

Factor Assessment

Factor 1: Air Quality Data

The EPA considered 8-hour ozone design values in ppm for air quality monitors in the area of analysis based on data for the 2014-2016 period (i.e., the 2016 design value, or DV). This is the most recent three-year period with fully-certified air quality data. The design value is the 3-year average of the annual 4th highest daily maximum 8-hour average ozone concentration.[7] The 2015 NAAQS are met when the design value is 0.070 ppm or less. Only ozone measurement data collected in accordance with the quality assurance (QA) requirements using approved (FRM/FEM) monitors are used for NAAQS compliance determinations.[8] The EPA uses FRM/FEM measurement data residing in the EPA's Air Quality System (AQS) database to calculate the ozone design values. Individual violations of the 2015 ozone NAAQS that the EPA determines have been caused by an exceptional event that meets the administrative and technical criteria in the Exceptional Events Rule[9] are not included in these calculations. Whenever several monitors are located in a county (or designated nonattainment area), the design value for the county or area is determined by the monitor with the highest valid design value. The presence of one or more violating monitors (i.e. monitors with design values greater than 0.070 ppm) in a county or other geographic area forms the basis for designating that county or area as nonattainment. The remaining four factors are then used as the technical basis for determining the spatial extent of the designated nonattainment area surrounding the violating monitor(s) based on a consideration of what nearby areas are contributing to a violation of the NAAQS.

The EPA identified monitors where the most recent design values violate the NAAQS, and examined historical ozone air quality measurement data (including previous design values) to understand the nature of the ozone ambient air quality problem in the area. Eligible monitors for providing design value data generally include State and Local Air Monitoring Stations (SLAMS) that are operated in accordance with 40 CFR part 58, appendix A, C, D and E and operating with an FRM or FEM monitor. These requirements

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[7] The specific methodology for calculating the ozone design values, including computational formulas and data completeness requirements, is described in 40 CFR part 50, appendix U.

[8] The QA requirements for ozone monitoring data are specified in 40 CFR part 58, appendix A. The performance test requirements for candidate FEMs are provided in 40 CFR part 53, subpart B.

[9] The EPA finalized the rule on the Treatment of Data Influenced by Exceptional Events (81 FR 68513) and the guidance on the Preparation of Exceptional Events Demonstrations for Wildfire Events in September of 2016. For more information, see *https://www.epa.gov/air-quality-analysis/exceptional-events-rule-and-guidance.*

must be met in order to be acceptable for comparison to the 2015 ozone NAAQS for designation purposes. All data from Special Purpose Monitors (SPMs) using an FRM or FEM are eligible for comparison to the NAAQS, subject to the requirements given in the March 28, 2016 Revision to Ambient Monitoring Quality Assurance and Other Requirements Rule (81 FR 17248).

The 2014-2016 design values for counties in the area of analysis are shown in Table 2.

Table 2. Air Quality Data (all values in ppm)

County, State	State Recommended Nonattainment?	AQS Site ID	2014-2016 DV	2014 4th highest daily max value	2015 4th highest daily max value	2016 4th highest daily max value
Box Elder, UT	No	49-003-0003	**0.067**	0.067	0.068	0.067
		49-003-7001	0.059	0.061	0.067	0.051
Davis, UT	Yes	49-011-0004	**0.074**	0.074	0.073	0.076
Juab, UT	No	No monitor	N/A			
Morgan, UT	No	No monitor	N/A			
Salt Lake, UT	Yes	49-035-2004	N/A	0.064	N/A	N/A
		49-035-3006	**0.075**	0.072	0.081	0.074
		49-035-3013	N/A	N/A	0.074	0.076
Summit, UT	No	No monitor	N/A			
Tooele, UT	Yes (partial)	49-045-0003	N/A	0.069	N/A	N/A
		49-045-0004	N/A	N/A	0.071	0.072
Utah, UT	Yes (partial)	49-049-0002	0.071	0.068	0.073	0.072
		49-049-5010	**0.073**	0.076	0.071	0.072
Wasatch, UT	No	No Monitor	N/A			
Weber, UT	Yes (partial)	49-057-0002	0.071	0.070	0.072	0.072
		49-057-1003	**0.072**	0.070	0.074	0.073

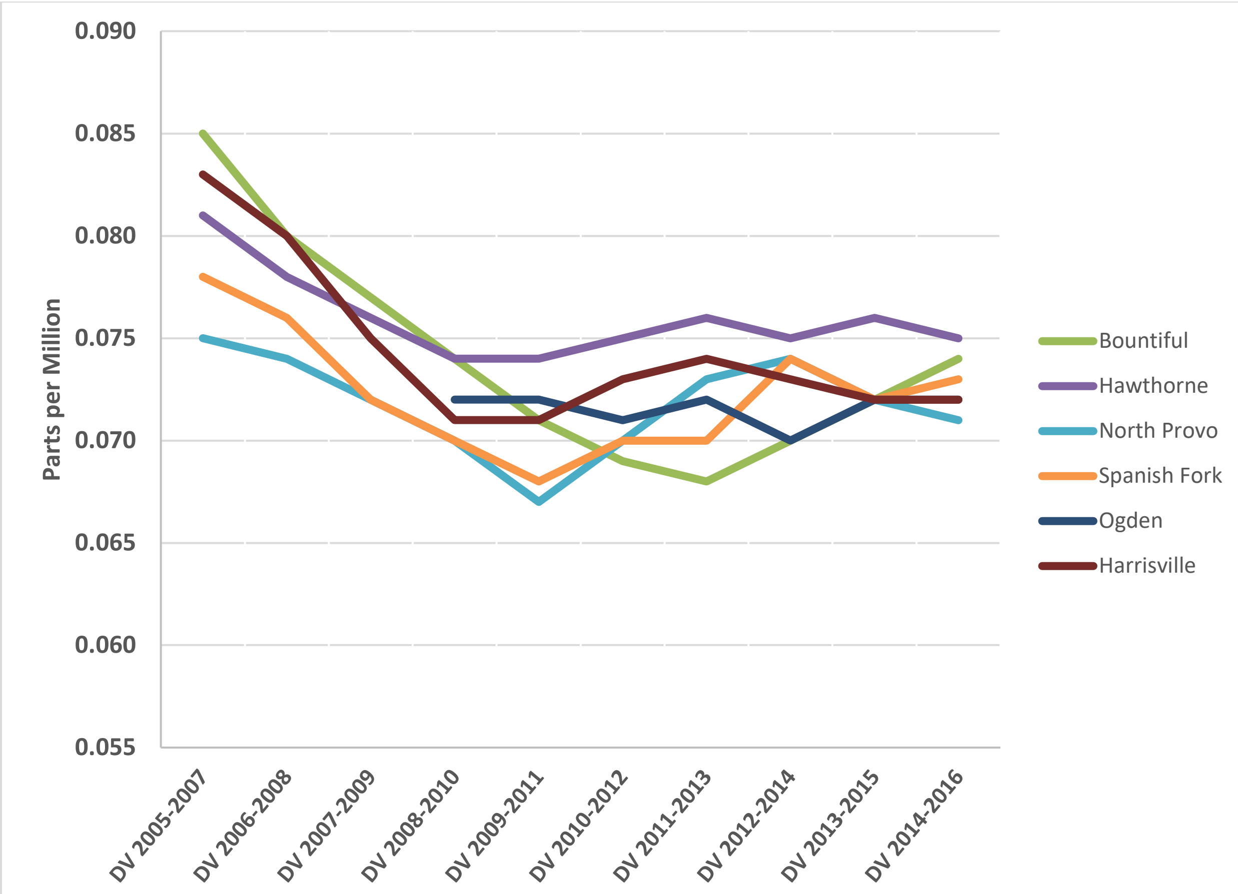
The highest design value in each county is indicated in bold type.
N/A means that the monitor did not meet the completeness criteria described in 40 CFR, part 50, Appendix U, or no data exists for the county.

Davis, Salt Lake, Utah, and Weber Counties show violations of the 2015 ozone NAAQS, therefore these counties are included in the final nonattainment areas. A county (or partial county) must also be designated nonattainment if it contributes to a violation in a nearby area. Counties adjacent to counties with violating monitors were also evaluated. These include: Tooele, Box Elder, Summit, Juab, Morgan, and Wasatch Counties.

Figure 1, shown previously, identifies the Northern Wasatch Front and Southern Wasatch Front final nonattainment areas, the county boundaries, and the violating monitors. Table 2 identifies the design values for all monitors in the area of analysis, and Figure 2 shows the historical trend of design values for the violating monitors. As indicated on the map, there are six violating monitors that are located in the area of analysis. Four are located in the Northern Wasatch Front area (Bountiful, located at Viewmont High School in Davis County; Hawthorne, at Hawthorne Elementary School in Salt Lake City, Ogden in Weber County; and Harrisville at Majestic Elementary School, north of Ogden, also in Weber County) and two are located in the Southern Wasatch Front area (North Provo and Spanish Fork at the Spanish Fork-Springville Airport in Utah County). Additional monitors in the Salt Lake City-Provo-Orem CSA not violating the 2015 ozone

NAAQS are in Brigham City, in Box Elder County, and the monitor of the Northwest Band of Shoshone Indian Tribe in Washakie Junction, also in Box Elder County.

Figure 2. Three-Year Design Values for Violating Monitors.



Based on Figure 2, ozone monitors in Salt Lake and Weber Counties have consistently had design values above the level of the 2015 ozone NAAQS. Monitors in Utah and Davis Counties historically were above the level of 2015 standard, then dropped below the standard based on the 2011 to 2013 DVs, but more recently have recorded new violations.

Factor 2: Emissions and Emissions-Related Data

The EPA evaluated ozone precursor emissions of nitrogen oxides (NO_x) and volatile organic compounds (VOC) and other emissions-related data that provide information on areas contributing to violating monitors.

<u>Emissions Data</u>

The EPA reviewed data from the 2014 National Emissions Inventory (NEI). For each county in the area of analysis, the EPA examined the magnitude of large sources (NO_x or VOC emissions greater than 100 tons per year) and small point sources and the magnitude of county-level emissions reported in the NEI. These county-level emissions represent the sum of emissions from the following general source categories: point sources, non-point (i.e., area) sources, non-road mobile, on-road mobile, and fires. Emission levels from sources in a nearby area indicate the potential for the area to contribute to monitored violations.

Table 3 provides a county-level emissions summary of NO_x and VOC (given in tons per year (tpy)) emissions for counties in the area of analysis.

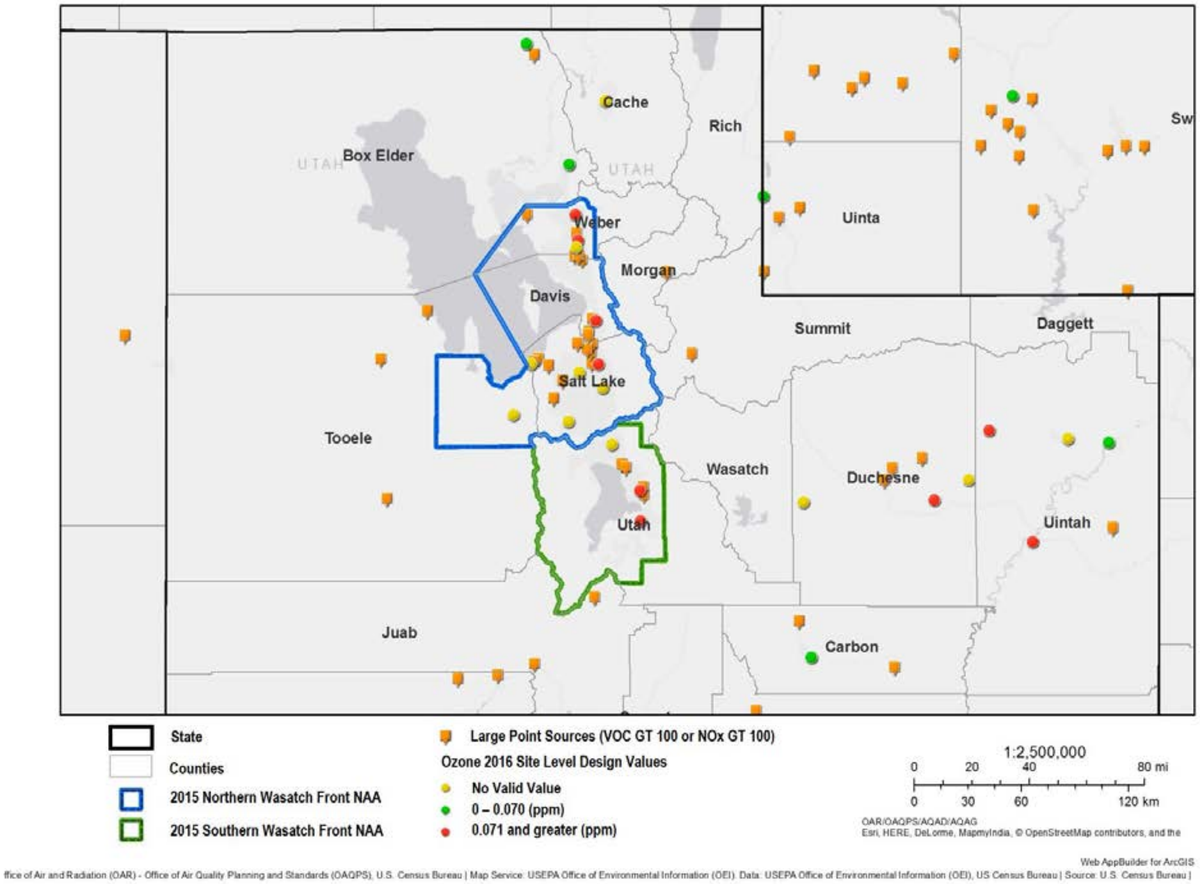
Table 3. Total County-Level NOx and VOC Emissions.

County	State Recommended Nonattainment	Total NO_x (tpy)	Total VOC (tpy)
Salt Lake	Yes	27,011	21,084
Utah	Yes (partial)*	13,208	10,219
Davis	Yes	6,623	6,801
Tooele	Yes (partial)*	5,022	3,484
Box Elder	No	4,579	4,635
Weber	Yes (partial)*	4,948	4,770
Summit	No	3,937	2,346
Juab	No	1,973	1,726
Morgan	No	2,181	1,387
Wasatch	No	1,143	1,737
	Area Wide:	70,625	58,189

* For state recommended partial counties, the emissions shown are for the entire county.

In addition to reviewing county-wide emissions of NO_x and VOC in the area of analysis, the EPA also reviewed emissions from large point sources. The location of these sources, together with the other factors, can help inform nonattainment boundaries. The locations of the large point sources are shown in Figure 3 below. The final nonattainment boundaries are also shown.

Figure 3. Large Point Sources in the Area of Analysis



As shown in Table 3, Salt Lake County has the highest emissions of both VOC and NOx – more than double the emissions of Utah County, which has the next highest emissions. Davis County has approximately one quarter the level of emissions of Salt Lake County. Toole, Box Elder and Summit Counties have emissions that are somewhat lower than those of Davis County while Juab, Morgan and Wasatch Counties have the lowest level of emissions of the counties in the area of analysis.

Figure 3 shows that there is a heavy concentration of large point sources in Salt Lake County. Utah, Davis and Weber Counties also have several large point sources. Toole County, which is a geographically large county on the western edge of the area of analysis has three large point sources that are somewhat distant from the core metropolitan area.

<u>Population density and degree of urbanization</u>

In this part of the factor analysis, the EPA evaluated the population and vehicle use characteristics and trends of the area as indicators of the probable location and magnitude of non-point source emissions. These include emissions of NO_x and VOC from on-road and non-road vehicles and engines, consumer products, residential fuel combustion, and consumer services. Areas of dense population or commercial development are an indicator of area source and mobile source NO_x and VOC emissions that may contribute to violations of the NAAQS. Table 4 shows the population, population density, and population growth information for each county in the area of analysis. Figure 4 shows the county-level population for the area of analysis, and Figure 5 shows the population density by census tract for the area of analysis.

Table 4. Population and Growth

County Name	State Recommended Nonattainment?	2010 Population	2015 Population	2015 Populations Density (per sq. mi.)	Absolute Change in Population (2010-2015)	Population % Change (2010-2015)
Salt Lake County	Yes	1,029,655	1,107,314	1,492	77,659	8
Utah County	Yes (partial)*	516,564	575,205	287	58,641	11
Davis County	Yes	306,479	336,043	1,125	29,564	10
Weber County	Yes (partial)*	231,236	243,645	423	12,409	5
Tooele County	Yes (partial)*	58,218	62,952	9	4,734	8
Box Elder County	No	49,975	52,097	9	2,122	4
Summit County	No	36,324	39,633	21	3,309	9
Wasatch County	No	23,530	29,161	25	5,631	24
Morgan County	No	9,469	11,065	18	1,596	17
Juab County	No	10,246	10,594	3	348	3
* For state recommended partial counties, the data are for the entire county.						

Source: U.S. Census Bureau population estimates for 2010 and 2015.
www.census.gov/data.html.

Figure 4. County-Level Population

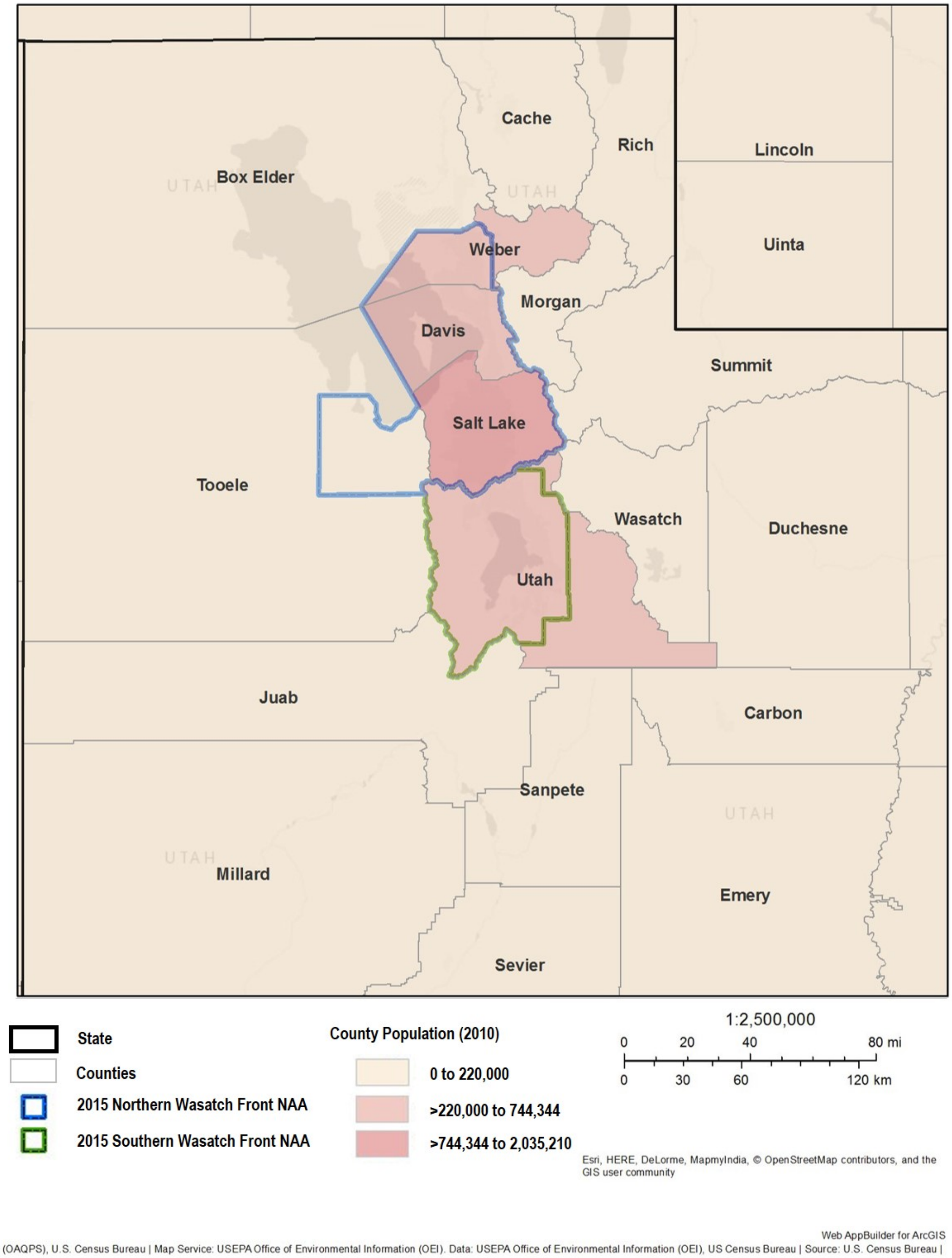


Figure 5. Population Density by Census Tract (2010)

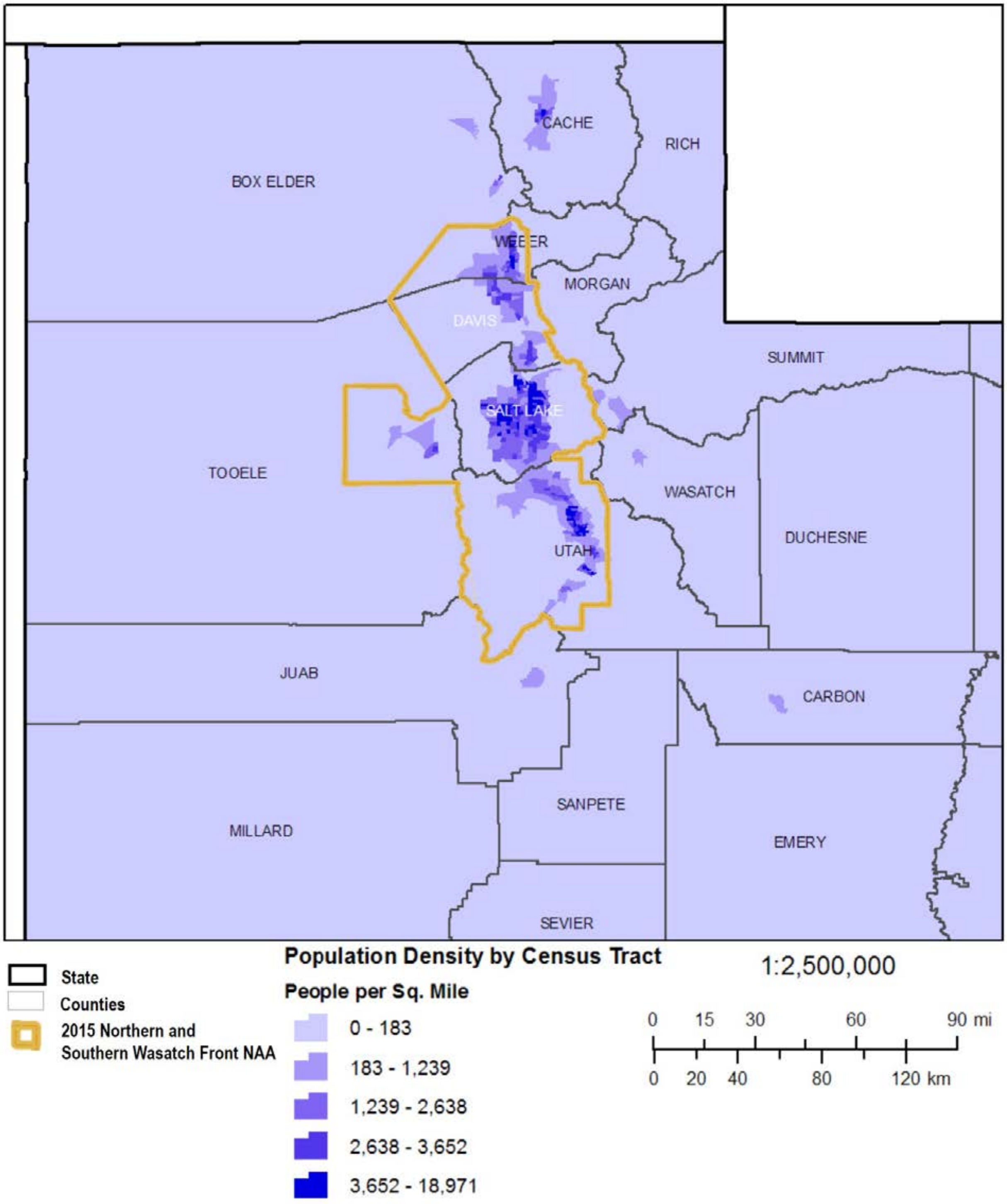


Table 4, along with Figures 4 and 5, show that the majority of the population resides in Salt Lake, Utah, Davis, and Weber Counties. Salt Lake County has a significantly higher population than the other counties – almost twice the population of Utah County, three times that of Davis County and more than four times that of Weber County. The other five counties all have much less than 10 percent of the population of Salt Lake County. Salt Lake and Davis County have the highest population densities of 1,492 and 1,125, respectively.

This is more than two to three times that of Weber County and four to five times that of Utah County. The remaining counties have significantly lower population densities of less than 25 people per square mile. As a region, the area is experiencing significant population growth, ranging from 3 to 24 percent. The two counties with the highest percentage population change are two of the least populated counties – Wasatch and Morgan. Of the four counties with the highest population and highest population density, Utah and Davis County had at or just above 10 percent growth, while Salt Lake County had 8 percent growth and Weber has 5 percent growth. As shown by Figure 5, the portions of Utah, Weber, and Tooele Counties that the State has excluded from its nonattainment area recommendation are the least populated and least densely populated areas of those counties.

The State's analysis in their TSD provided with their boundary recommendation provides an examination of population density and urbanization and is included in italicized text below.

> *There are two very noticeable features of the CSA. The first feature is the small area that is urbanized compared to the rural and uninhabited portions of the counties. The second feature is the large size of the CSA. The Salt Lake City-Provo-Orem CSA contains ten counties and covers 25,365 square miles (larger than West Virginia and nine other US states). It extends east/west from the Nevada border to the southern Wyoming border, a distance of over 220 miles, and south from the Idaho border approximately 100 miles. Each of the MSAs within the CSA includes densely populated areas, sparsely populated areas, and very large areas with no population at all. The sparse or unpopulated areas are due to extended desert in the west and extreme mountainous terrain in the east. The largest concentration of both population and industry is found in the low valleys west of, and adjacent to, the Wasatch Front. Smaller concentrations of population are also found in some of the higher valleys east of the Wasatch Range, but there are generally few or no major industrial sources located in these areas.*

Traffic and Vehicle Miles Travelled (VMT)

The EPA evaluated the commuting patterns of residents, as well as the total vehicle miles traveled (VMT) for each county in the area of analysis. In combination with the population/population density data and the location of main transportation arteries, this information helps identify the probable location of non-point source emissions. A county with high VMT and/or a high number of commuters is generally an integral part of an urban area and high VMT and/or high number of commuters indicates the presence of motor vehicle emissions that may contribute to violations of the NAAQS. Rapid population or VMT growth in a county on the urban perimeter may signify increasing integration with the core urban area, and thus could indicate that the associated area source and mobile source emissions may be appropriate to include in the nonattainment area. In addition to VMT, the EPA evaluated worker data collected by the U.S. Census Bureau[10] for the counties in the area of analysis. Table 5 shows the traffic and commuting pattern data, including total VMT for each county in the area of analysis, number of residents who work in each county, number of residents that work in counties with violating monitors, and the percent of residents working in counties with violating monitors. The values in Table 5 are 2014 data.

[10] The worker data can be accessed at: http://onthemap.ces.census.gov/.

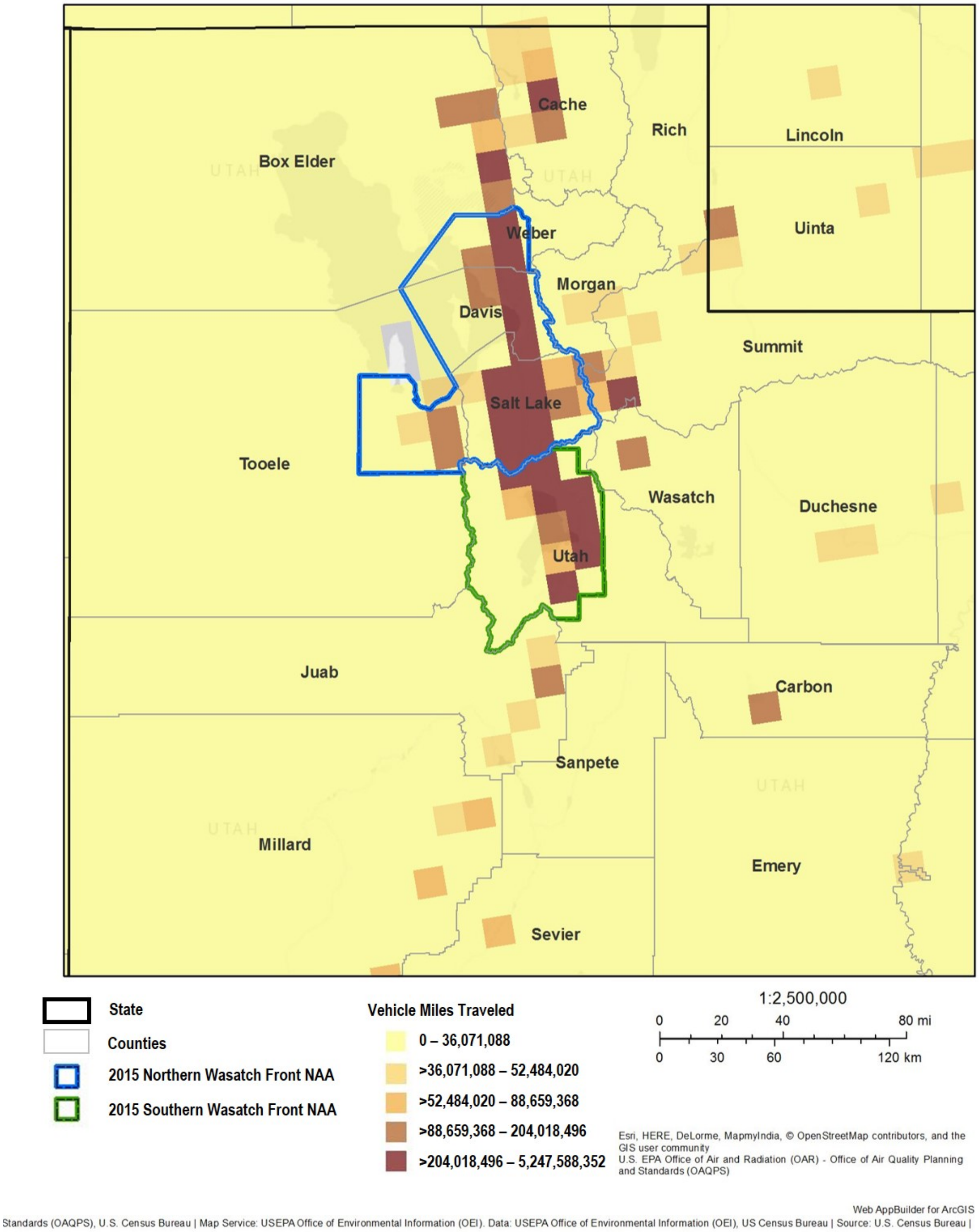
Table 5. Traffic and Commuting Patterns

County	State Recommended Nonattainment?	2014 Total VMT (Million Miles)	Number of County Residents Who Work	Number Commuting to or Within Counties with Violating Monitor(s)	Percentage Commuting to or Within Counties with Violating Monitor(s)
Salt Lake	Yes	9,079	505,823	483,032	95.5%
Utah	Yes (partial)*	4,085	218,761	204,465	93.5%
Davis	Yes	2,590	132,850	125,975	94.8%
Weber	Yes (partial)*	1,647	102,326	94,822	92.7%
Box Elder	No	911	24,932	11,335	45.5%
Tooele	Yes (partial)*	822	26,570	17,098	64.4%
Summit	No	763	21,640	9,345	43.2%
Juab	No	369	4,346	1,795	41.3%
Wasatch	No	353	12,577	5,502	43.8%
Morgan	No	133	4,671	3,134	67.1%
Total		20,752	1,054,496	956,503	90.7%

* For state recommended partial counties, the data provided are for the entire county. Counties with a monitors violating the NAAQS are indicated in bold.

To show traffic and commuting patterns, Figure 6 overlays twelve-kilometer gridded VMT from the 2014 NEI with a map of the transportation arteries.

Figure 6. Twelve Kilometer Gridded VMT (Miles) Overlaid with Transportation Arteries



The 2014 VMT in Table 5 illustrates that the vast majority of vehicle trips occur in four counties. Weber, Davis, Salt Lake, and Utah Counties; which have VMT levels ranging from just over 1,600 in Weber County to just over 9000 in Salt Lake County. Figure 6 illustrates that traffic patterns are heaviest on a north-south axis through the area of analysis. This corresponds with the major traffic corridor of Interstate 15. In addition, the heavier traffic areas shown in Figure 6 largely correspond with the more densely populated areas as shown in Figure 5, above – including the counties of Weber, Davis, Salt Lake, and Utah. Average daily traffic rapidly diminishes beyond this central core as indicated by the lower VMT values for the other five counties in the area of analysis and by Figure 6. The commuting information indicates that the number of commuters traveling to or within a county with a violating monitor is more than twice as high for the four counties with violating monitors (each over 90%) than for the other counties - with the exception of Tooele and Morgan Counties. These two counties have approximately 65% of commuters traveling to a county with a violating monitor. As noted previously, Tooele County is relatively sparsely populated except for a small area close to the border of Salt Lake County.

Factor 3: Meteorology

Evaluation of meteorological data helps to assess the fate and transport of emissions contributing to ozone concentrations and to identify areas potentially contributing to the monitored violations. Results of meteorological data analysis may inform the determination of nonattainment area boundaries. In order to determine how meteorological conditions, including, but not limited to, weather, transport patterns, and stagnation conditions, could affect the fate and transport of ozone and precursor emissions from sources in the area, the EPA evaluated 2014-2016 HYSPLIT (HYbrid Single-Particle Lagrangian Integrated Trajectory) trajectories at 100, 500, and 1000 meters above ground level (AGL) that illustrate the three-dimensional paths traveled by air parcels to a violating monitor. Figures 7 through 12 show the 24-hour HYSPLIT back trajectories for each exceedance day (i.e., daily maximum 8 hour values that exceed the 2015 ozone NAAQS) for the violating monitors.

Figure 7. HYSPLIT Back Trajectories for Hawthorne

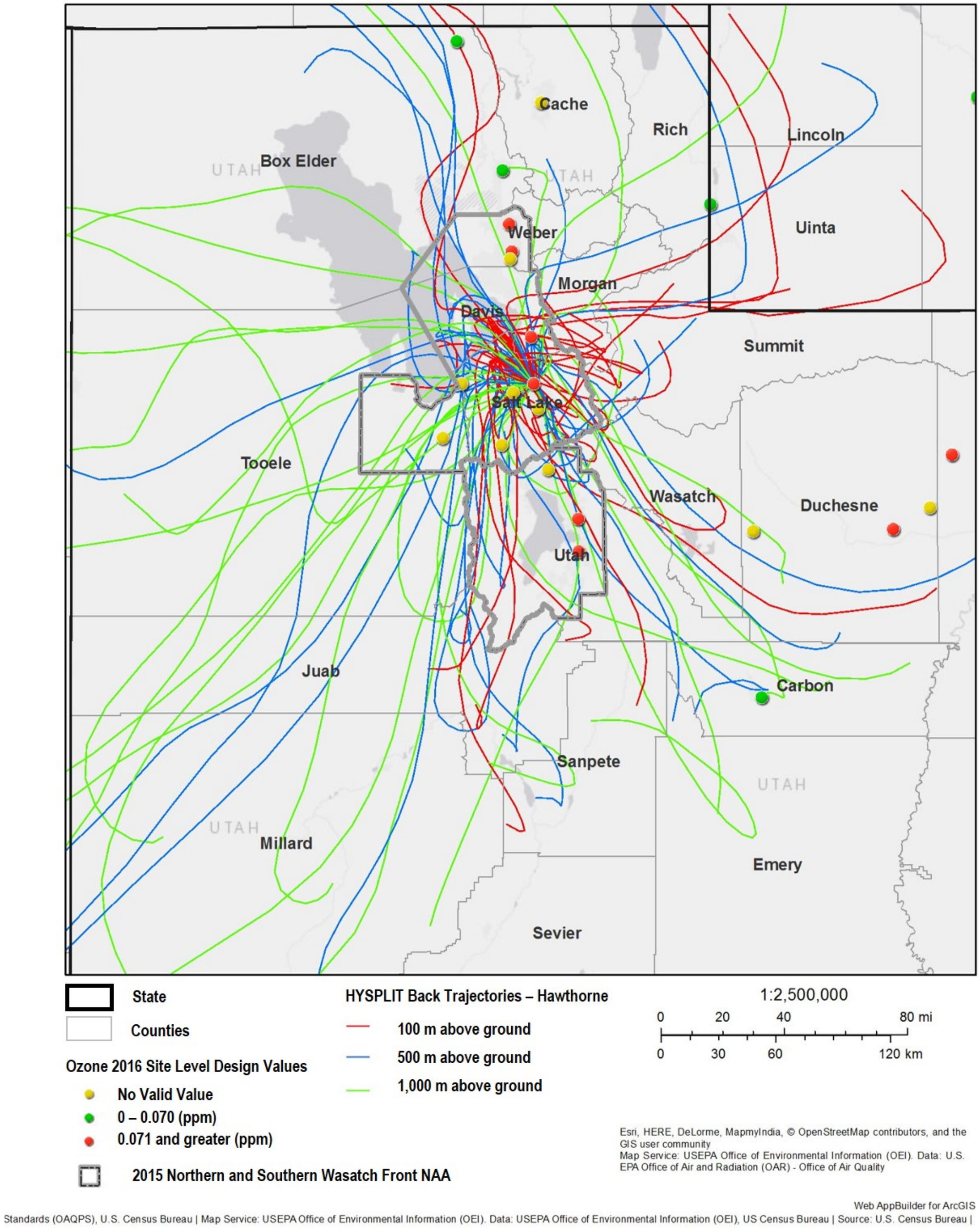


Figure 8. HYSPLIT Back Trajectories for Ogden

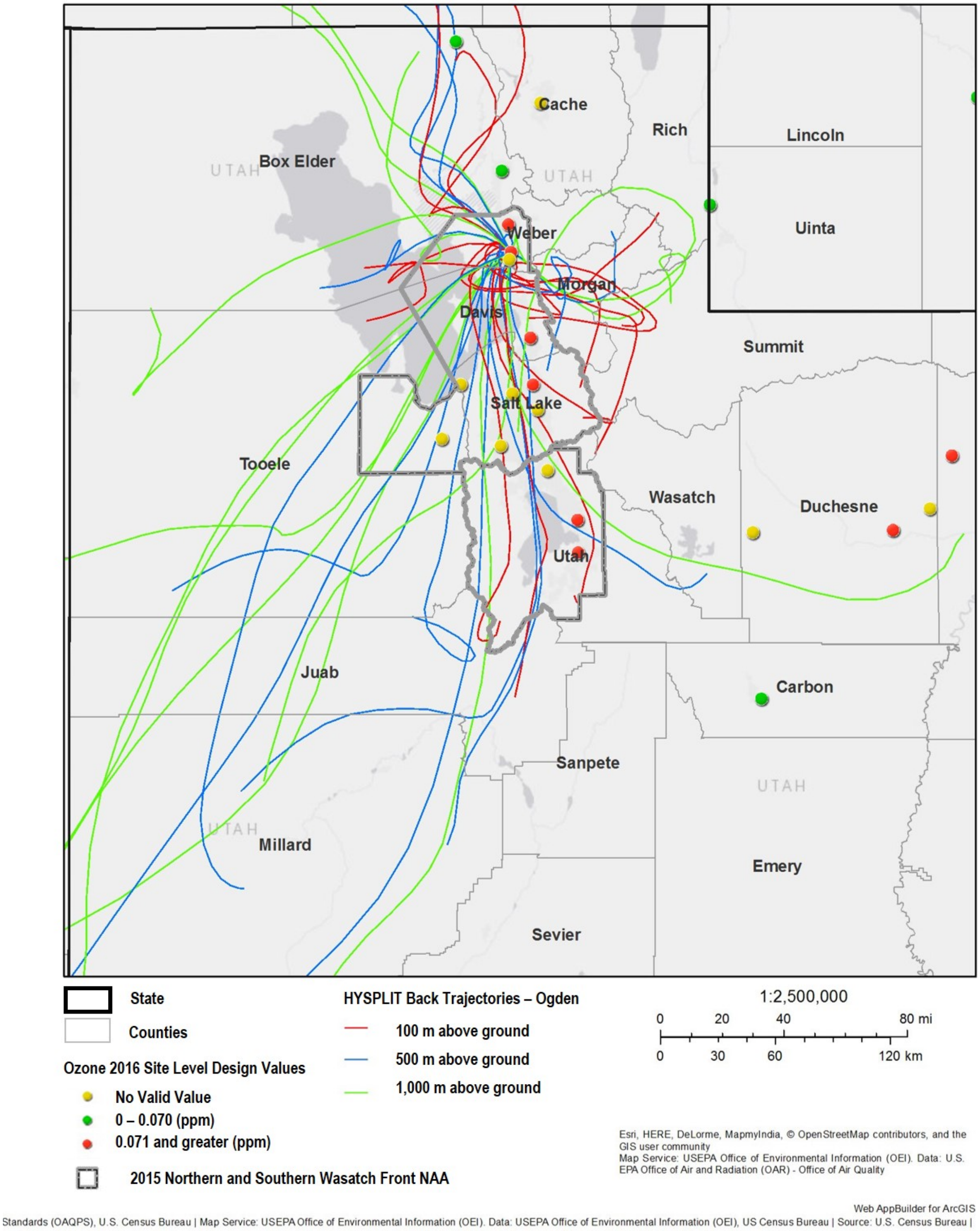


Figure 9. HYSPLIT Back Trajectories for Bountiful

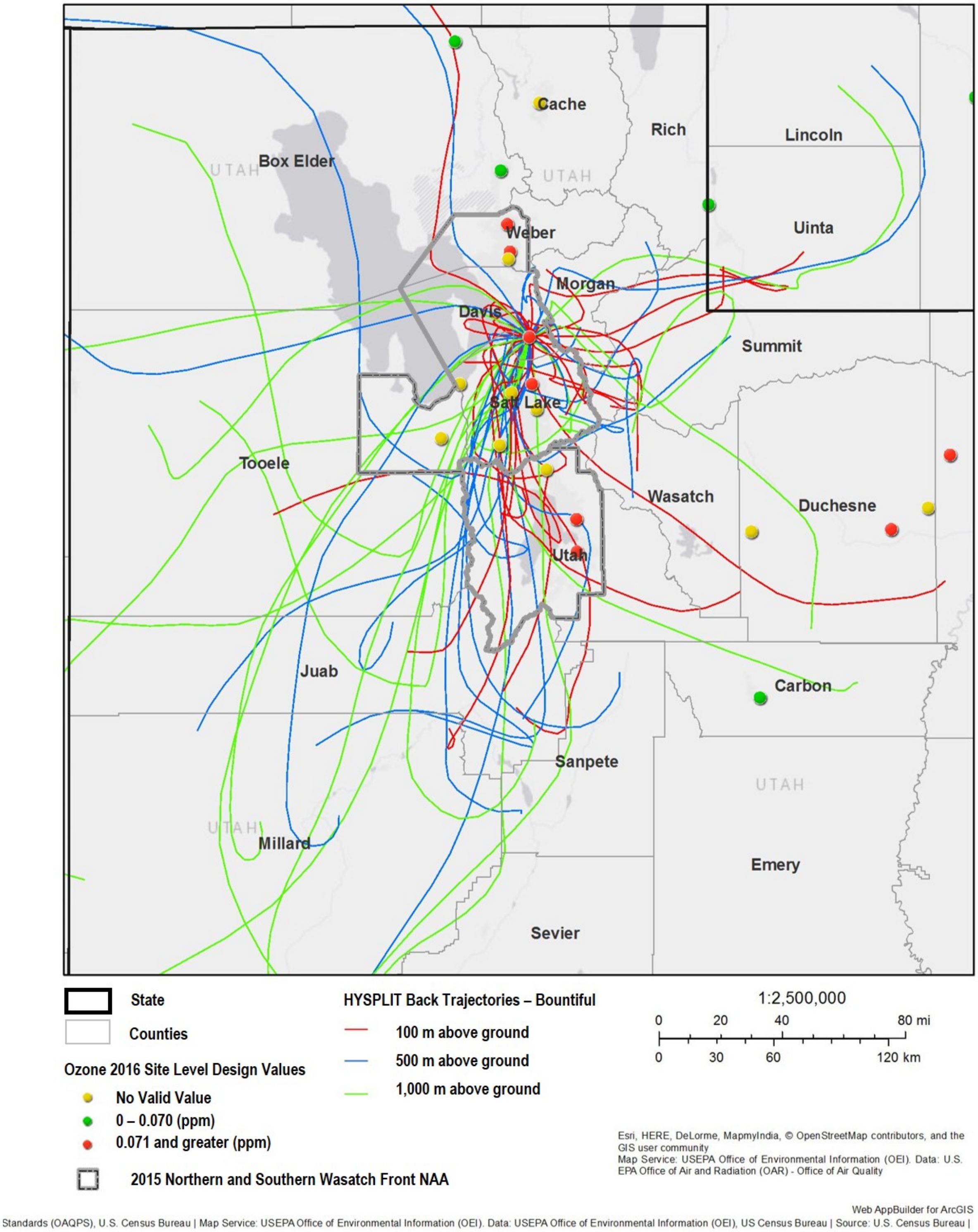


Figure 10. HYSPLIT Back Trajectories for Harrisville

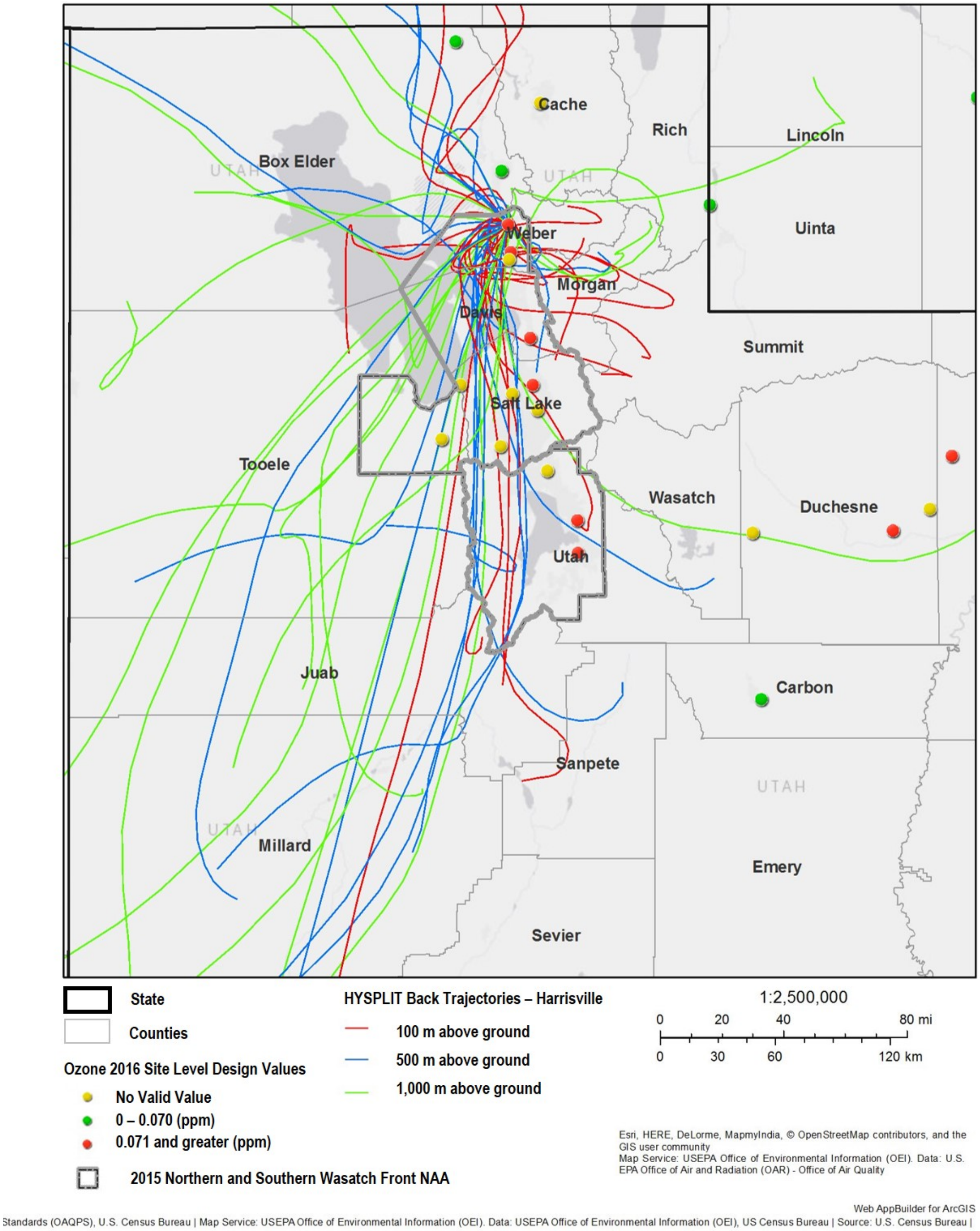


Figure 11. HYSPLIT Back Trajectories for North Provo

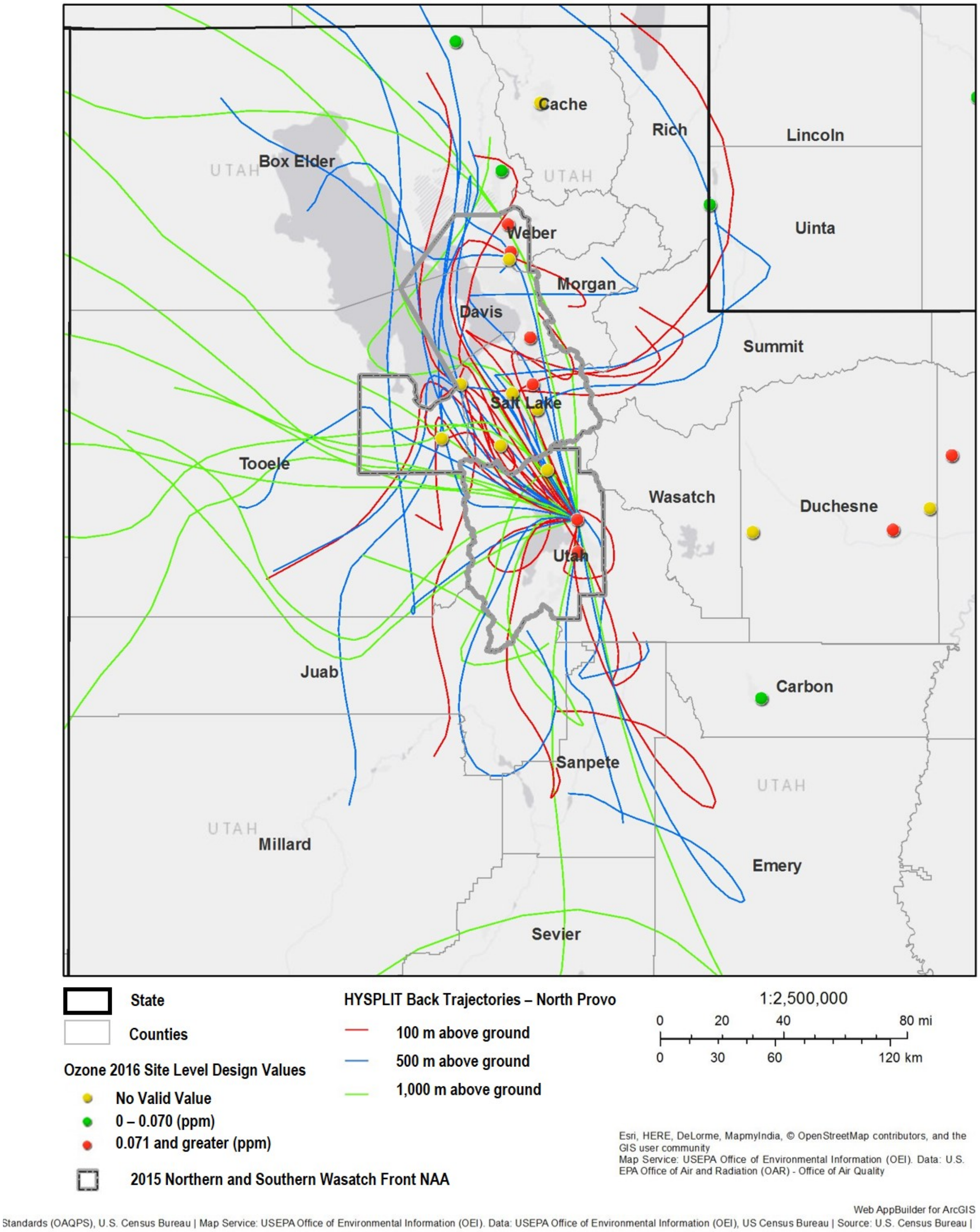
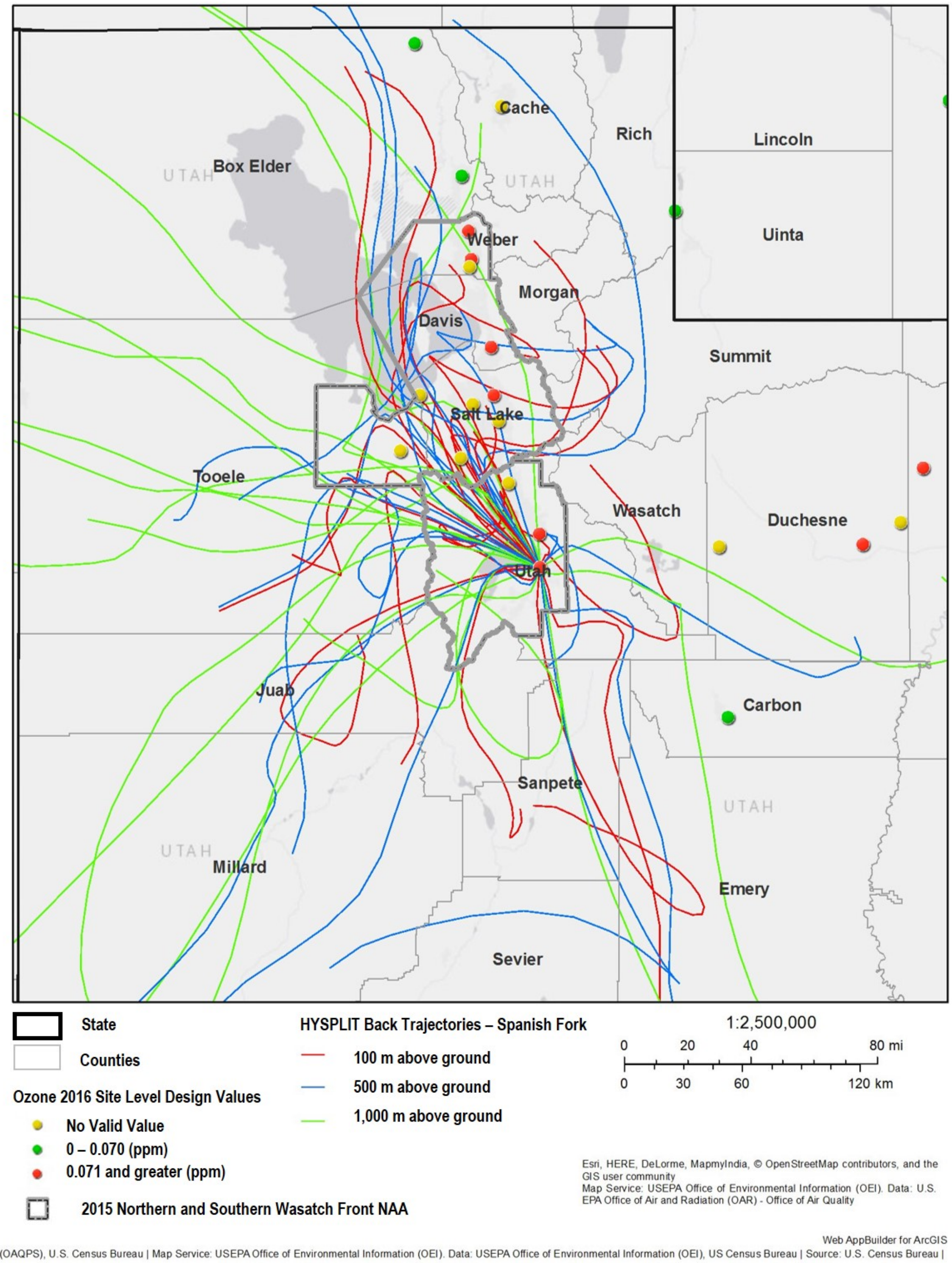


Figure 12. HYSPLIT Back Trajectories for Spanish Fork



The meteorology of the urbanized Wasatch Front is strongly influenced by the Wasatch mountain range to the east of the urban corridor and the Great Salt Lake and Utah Lake, generally to the west of the urbanized area. High ozone levels in the Wasatch front area usually occur in association with a semi-permanent high pressure ridge stationary over the intermountain region, along with clear skies, intense direct sunlight, and stagnant air with very light surface winds. When these meteorological conditions occur together, they aid in the formation of ozone while at the same time providing minimal vertical mixing.

Day-to-day transport of the ozone along the Wasatch Front is mainly influenced by the diurnal effects of the local lake on-shore/off-shore flow coupled with up-slope/down-slope airflow in the mountains. General westward movement occurs during the late evening and nighttime hours and eastward movement occurs during the daylight hours. This is a typical mountain/valley flow.

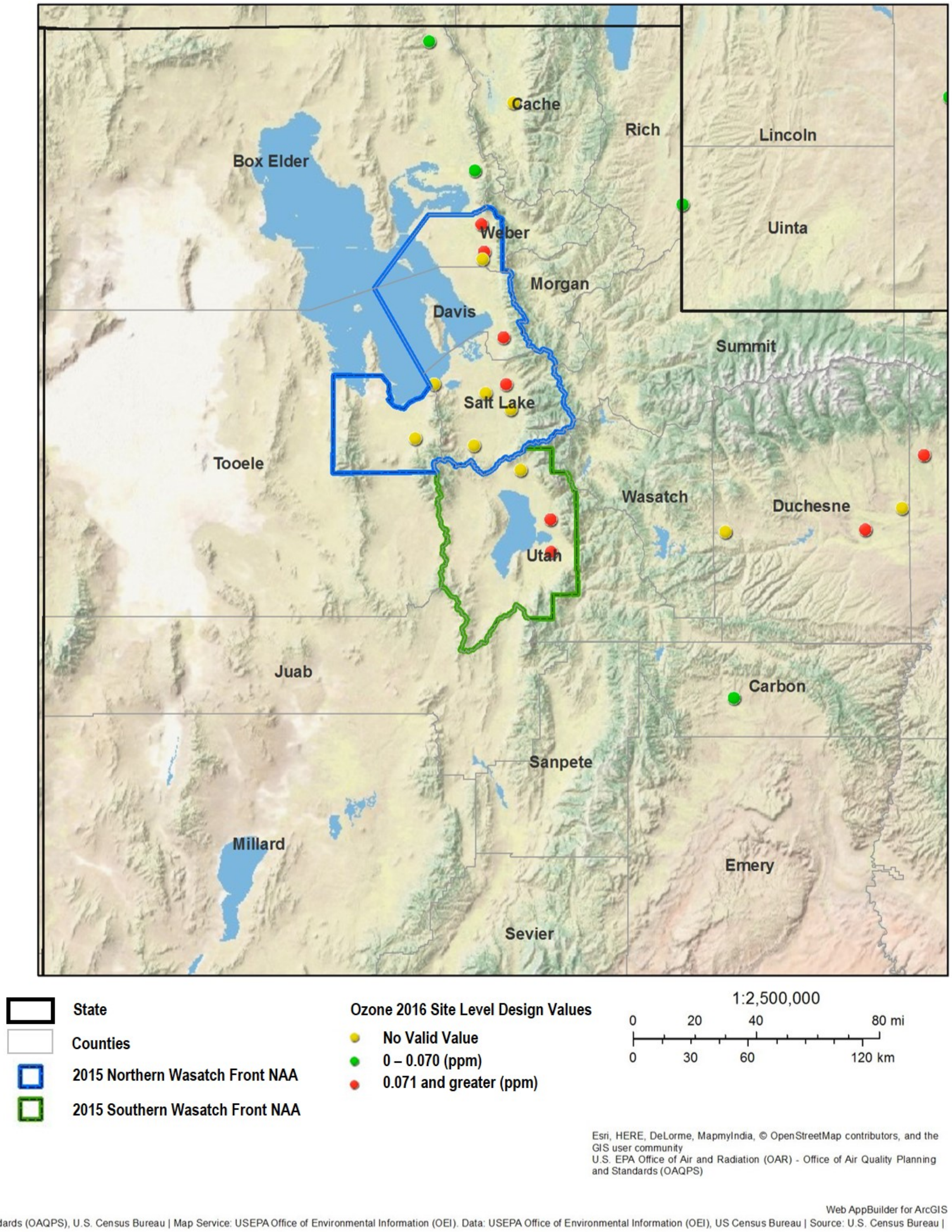
The above meteorological conditions, when combined with topography and other factors, help to define the airsheds of the northern and southern Wasatch Front areas. The back trajectory analysis done with HYSPLIT (Figures 7 through 12) indicates that emissions originating within Davis and Salt Lake Counties as well as the southern portion of Weber County, the northern portion of Utah County, and the eastern portion of Tooele County, appear to be the primary influencer on violating monitors. The EPA notes that a high frequency of days show parcels of air passing through the urbanized eastern portion of Tooele County that influence violating monitors. Additionally, very few days show parcels of air originating in both western Tooele County and Box Elder County that influence violating monitors. In general, the HYSPLIT analysis shows wind patterns predominantly from the south and from the north with the heaviest concentration of trajectories traveling through Salt Lake, Weber, Davis, and Utah Counties. This is consistent with the meteorological pattern discussed earlier, given that some local topographical influence on meteorology occurs on scales smaller than the HYSPLIT gridded meteorology.

Factor 4: Geography/topography

Consideration of geography or topography can provide additional information relevant to defining nonattainment area boundaries. Analyses should examine the physical features of the land that might define the airshed. Mountains or other physical features may influence the fate and transport of emissions as well as the formation and distribution of ozone concentrations. The absence of any such geographic or topographic features may also be a relevant consideration in selecting boundaries for a given area.

The EPA used geography/topography analysis to evaluate the physical features of the land that might affect the airshed and, therefore, the distribution of ozone over the area. Figure 13 provides an illustration of the topographical features in the area of analysis.

Figure 13. Topographic illustration of the physical features



There are two geographic features of this region that can affect airflow in the air of analysis. The impact of the Utah and Great Salt Lakes to the west and northwest of the urban centers are discussed in the previous section on meteorology. The impact of the mountain ranges is also briefly discussed on that section. The

State's analysis in their TSD, provided with their boundary recommendation, provides a thorough discussion of the impact of the mountain ranges and is included in italicized text below.

> *The Wasatch Front is located along the eastern edge of the Great Basin. The Wasatch Range, extending from near the Idaho border to Mt. Nebo at the southern tip of the Northern Rocky Mountains, is a formidable obstacle to surface air mass movement to and from the east. The Wasatch Mountains rise abruptly to elevations of between 4,000 to 6,000 feet above the valley floor and help to define the Wasatch Front urban areas from Brigham City on the north to the numerous metropolitan areas in Utah County on the south. These valleys are bound on the West by the Great Salt Lake in the north and the Oquirrh Mountains, which also rise 4,000 to 5,000 feet above the valley floor, in the south. In an area of flat terrain one would expect an air mass to gradually be transported in a direction consistent with the prevailing air flow. Conversely, in an area of mountainous terrain, as is the case of the valleys along the Wasatch Front, one would expect the terrain to define the air mass boundaries and movement. With prevailing winds from the west through the north, the high terrain with its bowl shaped valleys that open to the north and west routinely functions to block any eastward horizontal movement of a stagnant air mass. In effect, the local topography actually contains stagnant air masses within these valleys.*
>
> *As discussed in the meteorology section, it has been found in several studies that concentrations of ozone trapped in large mountain valleys along the Wasatch Front, such as the Salt Lake Valley and Utah Valley, actually move horizontally within or in and out of the valleys with the diurnal mountain-valley flow. In the Salt Lake Valley, for instance, the nighttime flow generally moves the air to the northwest over the eastern portion of the Great Salt Lake while the daytime flow moves the same air back southeastward into the valley where it is contained by the Wasatch Range. In Utah Valley, the air is more contained and generally moves westward over Utah Lake in the evening and eastward during the day. In some instances, however, the air mass in either the Salt Lake Valley or Utah Valley has moved north or south to affect the other valley. In the region north of Salt Lake City, air masses have a tendency to move both north and south along the Wasatch Front, as well as east and west with the diurnal flow.*
>
> *… much of the eastern area of the Wasatch Front counties is at a much higher elevation than the adjacent western valleys, and should generally not experience the high concentrations of ozone produced in these urban valleys.*

The EPA agrees with Utah's assessment that the geography of the region makes trapping of local pollutants likely under summer stagnation events. Notably, the Wasatch mountain range prevents ozone from impacting the higher elevation, eastern portions of Weber and Utah Counties. The Traverse Range mountains divide the Salt Lake Valley and Utah Valley; which roughly corresponds with the boundary between the Northern and Southern Wasatch front nonattainment areas.

Factor 5: Jurisdictional boundaries

Once the geographic extent of the violating area and the nearby area contributing to violations is determined, the EPA considered existing jurisdictional boundaries for the purposes of providing a clearly defined legal boundary to carry out the air quality planning and enforcement functions for nonattainment areas. In defining the boundaries of the final nonattainment areas, the EPA considered existing jurisdictional boundaries, which can provide easily identifiable and recognized boundaries for purposes of implementing the NAAQS. Examples of jurisdictional boundaries include, but are not limited to: counties, air districts, areas of Indian country, metropolitan planning organizations, and existing nonattainment areas. If an existing jurisdictional boundary is used to help define the nonattainment area, it must encompass all of the area that has been identified as meeting the nonattainment definition. Where existing jurisdictional boundaries are not adequate or appropriate to describe the nonattainment area, the EPA considered other clearly defined and permanent landmarks or geographic coordinates for purposes of identifying the boundaries of the final designated areas.

The State's analysis in their TSD. provided with their boundary recommendation, provides an explanation of why jurisdiction supports the State's recommendation that the Wasatch Front be designated as two separate nonattainment areas.

> *Within the Salt Lake City-Provo-Orem CSA there are three MSAs and two distinct metropolitan planning organizations (MPO) that carry out transportation planning for those MSAs. Wasatch Front Regional Council is the MPO that carries out regional transportation planning in Salt Lake, Tooele, Davis, Weber, Morgan, and Box Elder counties. The Mountainland Association of Governments (MAG) is the MPO responsible for transportation planning in Utah County. These two areas are also designated as two separate nonattainment areas for $PM_{2.5}$. Designating all of these counties as one nonattainment area would create major hurdles for MAG and WFRC within the transportation planning and conformity requirements and obligations under the Act.*

Conclusion for Wasatch Front Area

Based on the assessment of factors described above, the EPA is not modifying Utah's recommendation to designate two separate areas with the boundaries recommended by the state: The Northern Wasatch Front area and the Southern Wasatch Front area. The EPA has concluded that the following counties meet the CAA criteria for inclusion in the final Northern Wasatch Front nonattainment area: all of Davis and Salt Lake Counties, and portions of Weber and Tooele Counties. The EPA has also concluded that a portion of Utah County meets the criteria for inclusion in the final Southern Wasatch front nonattainment area. These are the same counties included in, and the same boundaries for the Northern Wasatch Front and Southern Wasatch Front nonattainment areas for the 2006 $PM_{2.5}$ NAAQS - with the exception that no portion of Box Elder County would be included as part of the Northern Wasatch Front area for the 2015 ozone NAAQS.

The air quality monitors in Salt Lake, Davis, Utah, and Weber Counties indicate violations of the 2015 ozone NAAQS based on the 2016 design values, therefore all or portions of these counties are included in the final nonattainment areas. Tooele County does not have a monitor with complete 2014-2016 data, but the EPA has concluded that a portion of the county contributes to the ozone concentrations measured at monitors in violation of the 2015 ozone NAAQS. This conclusion is reached based on the significant number of back trajectories from that area to downwind violating monitors on days that those monitors are exceeding the NAAQS. On-road mobile and area sources from that area in Tooele County account for much of the VOCs and NO_x emitted in the County. That area also includes the more densely populated urban area of the county which is well integrated with the counties with violating monitors based on commuting patterns. The great majority (more than 85%) of Tooele County's population is contained within the area the

EPA is including in the Northern Wasatch Front nonattainment area. All of the areas the state has recommended and that the EPA is including in the two designated nonattainment areas are within Utah Valley and the valleys along the eastern and southern shores of the Great Salt Lake. The EPA is not modifying the State's recommendation not to include the portions of Utah and Weber County that are at higher elevations in the Wasatch Mountain range. As discussed, high ozone concentrations are generally found at the lower elevations while the mountain range prevents ozone, and ozone precursors from moving into eastern, higher elevation portions of counties. Moreover, we note that these portions of the counties are relatively rural, have low VMT, and do not contain any major sources.

Although Box Elder County was included within the 2006 $PM_{2.5}$ nonattainment boundary, the EPA finds sufficient evidence to exclude Box Elder from the 2015 ozone nonattainment boundary. The county includes two monitors that are attaining the 2015 ozone NAAQS. Although the EPA finds that the county contains emissions of ozone precursors from point, area, and mobile sources, the back trajectory analysis indicates that meteorological conditions result in these emissions infrequently influencing violating monitors within the final nonattainment area. Furthermore, commuting information shows that relatively few (approximately 11,000) people commute from Box Elder County into a county with a violating monitor.

Finally, the EPA is not including Summit, Juab, Wasatch, and Morgan Counties. All of these areas have low populations (less than 40,000) and population densities less than 25 per square mile. They also have significantly lower emissions than the counties and partial counties the EPA is including in the nonattainment area. Furthermore, topographic obstacles (Wasatch Mountains), as well as meteorology, prevent emissions in these areas from influencing violating monitors.

The EPA finds that the weight-of-evidence presented through the five-factor analysis supports the State's recommended boundaries for the Southern Wasatch Front and Northern Wasatch Front nonattainment areas for the 2015 ozone NAAQS. The EPA concludes that designating the nonattainment boundaries as proposed will support Utah's ability to focus resources on the emission sources and areas that most strongly contribute to the ozone problem along the Wasatch Front.

3.2 Technical Analysis for Uinta Basin

This technical analysis identifies the areas with monitors that violate the 2015 ozone NAAQS. It also provides EPA's evaluation of these areas and any nearby areas to determine whether those nearby areas have emissions sources that potentially contribute to ambient ozone concentrations at the violating monitors in the area, based on the weight-of-evidence of the five factors recommended in the EPA's ozone designations guidance and any other relevant information. In developing this technical analysis, the EPA used the latest data and information available to the EPA (and to the states and tribes through the Ozone Designations Mapping Tool and the EPA Ozone Designations Guidance and Data web page).[11] In addition, the EPA considered any additional data or information provided to the EPA by states or tribes.

The EPA evaluated emissions, air quality, and other information for counties in the Uinta Basin in Utah. Based on existing air quality studies (discussed later) – ozone production in the basin is a highly localized phenomenon. The Uinta basin is a winter ozone area, where violating ozone concentrations are dependent

[11] The EPA's Ozone Designations Guidance and Data web page can be found at *https://www.epa.gov/ozone-designations/ozone-designations-guidance-and-data.*

on stagnant winter conditions associated with strong temperature inversions. These conditions limit the influence of areas outside the topographic Uinta Basin. The Uinta Basin lies primarily within Uintah and Duchesne counties of Utah. The role of winter temperature inversions in producing ozone near the basin floor means that contributing emission sources are those at relatively low elevations within the basin. The only low elevation portion of the basin outside Uintah and Duchesne counties lies along the White River in Rio Blanco County, Colorado. The area of analysis was determined to be Uintah County and Duchesne County in Utah, and the White River valley in Rio Blanco County, Colorado. Uintah County is in the Vernal CBSA, while Duchesne and Rio Blanco Counties are not in CBSAs.

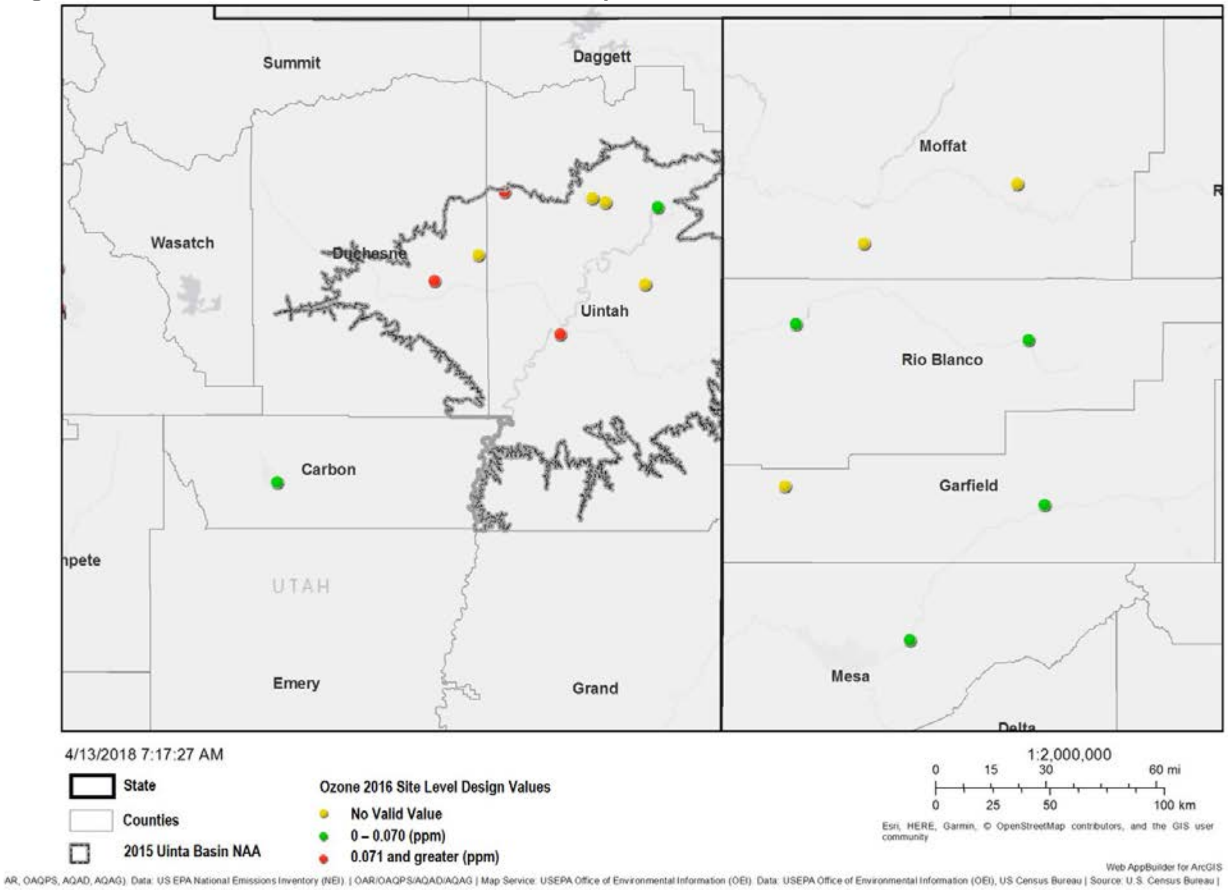
The five factors recommended in the EPA's guidance are:

1. Air Quality Data (including the design value calculated for each Federal Reference Method (FRM) or Federal Equivalent Method (FEM) monitor;
2. Emissions and Emissions-Related Data (including locations of sources, population, amount of emissions, and urban growth patterns);
3. Meteorology (weather/transport patterns);
4. Geography/Topography (including mountain ranges or other physical features that may influence the fate and transport of emissions and ozone concentrations); and
5. Jurisdictional Boundaries (e.g., counties, air districts, existing nonattainment areas, areas of Indian country, Metropolitan Planning Organizations (MPOs)).

As described in Section 1, the state of Utah recommended that only the portion of the Uinta Basin in townships at elevations below 6,000 feet be designated nonattainment, while the Ute Indian Tribe recommended that only the portion of the Uinta Basin around the Ouray monitor be designated nonattainment.

Figure 14 is a map of the EPA's final nonattainment boundary for the Uinta Basin area. The map shows the location of the ambient air quality monitors, county, and other jurisdictional boundaries.

Figure 14. EPA's Final Nonattainment Boundary for the Uinta Basin[12]



The EPA must designate as nonattainment any area that violates the NAAQS and any nearby areas that contribute to the violation in the violating area. Uintah and Duchesne Counties have monitors in violation of the 2015 ozone NAAQS, therefore these counties (or portions of these counties) are included in the final nonattainment area. As previously noted and as explained in more detail in the section discussing meteorology, the EPA determined based on existing air quality studies completed in the Uinta Basin, that sources in surrounding counties do not contribute to the violating area because of the unique geographic features of the area and the winter temperature inversion meteorology. The following sections describe the five factor analysis for the area within the Uinta Basin to determine the areas within the basin that are contributing to a violation of the 2015 ozone NAAQS. While the factors are presented individually, they are not independent. The five factor analysis process carefully considers the interconnections among the different factors and the dependence of each factor on one or more of the others, such as the interaction between emissions and meteorology for the area being evaluated.

[12] EPA is defining the nonattainment area boundary as the 6250-ft. contour line created from the 2013 USGS 10-meter seamless Digital Elevation Model (USGS NED n41w110 1/3 arc-second 2013 1 x 1 degree IMG). http://ned.usgs.gov/.

Factor Assessment

Factor 1: Air Quality Data

The EPA considered 8-hour ozone design values in ppm for air quality monitors in the area of analysis based on data for the 2014-2016 period (i.e., the 2016 design value, or DV). This is the most recent three-year period with fully-certified air quality data. The design value is the 3-year average of the annual 4th highest daily maximum 8-hour average ozone concentration.[13] The 2015 NAAQS are met when the design value is 0.070 ppm or less. Only ozone measurement data collected in accordance with the quality assurance (QA) requirements using approved (FRM/FEM) monitors are used for NAAQS compliance determinations.[14] The EPA uses FRM/FEM measurement data residing in the EPA's Air Quality System (AQS) database to calculate the ozone design values. Individual exceedances of the 2015 ozone NAAQS that the EPA determines have been caused by an exceptional event that meets the administrative and technical criteria in the Exceptional Events Rule[15] are not included in these calculations. Whenever several monitors are located in a county (or designated nonattainment area), the design value for the county or area is determined by the monitor with the highest valid design value. The presence of one or more violating monitors (i.e. monitors with design values greater than 0.070 ppm) in a county or other geographic area forms the basis for designating that county or area as nonattainment. The remaining four factors are then used as the technical basis for determining the spatial extent of the designated nonattainment area surrounding the violating monitor(s) based on a consideration of what nearby areas are contributing to a violation of the NAAQS.

The EPA identified monitors where the most recent design values violate the NAAQS, and examined historical ozone air quality measurement data (including previous design values) to understand the nature of the ozone ambient air quality problem in the area. Eligible monitors for providing design value data generally include State and Local Air Monitoring Stations (SLAMS) and tribal air monitoring stations that are operated in accordance with 40 CFR part 58, appendix A, C, D and E and operating with an FRM or FEM monitor. These requirements must be met in order to be acceptable for comparison to the 2015 ozone NAAQS for designation purposes. All data from Special Purpose Monitors (SPMs) using an FRM or FEM are eligible for comparison to the NAAQS, subject to the requirements given in the March 28, 2016 Revision to Ambient Monitoring Quality Assurance and Other Requirements Rule (81 FR 17248).

The 2014-2016 design values for counties in the Uinta Basin are shown in Tables 6 and 7 (State and Tribal jurisdiction). The design values shown reflect the concurrence on an exceptional event demonstration made by the Ute Indian Tribe of the Uintah and Ouray Reservation impacting ozone data collected on June 8 and 9, 2015. The Ute Tribe successfully showed that the ozone exceedances at tribal monitors on those days were caused by a stratospheric intrusion exceptional event.[16]

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[13] The specific methodology for calculating the ozone design values, including computational formulas and data completeness requirements, is described in 40 CFR part 50, appendix U.

[14] The QA requirements for ozone monitoring data are specified in 40 CFR part 58, appendix A. The performance test requirements for candidate FEMs are provided in 40 CFR part 53, subpart B.

[15] The EPA finalized the rule on the Treatment of Data Influenced by Exceptional Events (81 FR 68513) and the guidance on the Preparation of Exceptional Events Demonstrations for Wildfire Events in September of 2016. For more information, see *https://www.epa.gov/air-quality-analysis/exceptional-events-rule-and-guidance.*

[16] The EE was acted on by EPA on June 7, 2017 with concurrence from Sarah Dunham, Acting Assistant Administrator for the Office of Air and Radiation.

Table 6. Air Quality Data – Utah and Colorado State Land (all values in ppm)

County, State	State Recommended Nonattainment?	AQS Site ID	2014-2016 DV	2014 4th highest daily max value	2015 4th highest daily max value	2016 4th highest daily max value
Rio Blanco, CO	No	08-103-0006 (Rangely)	**0.063**	0.062	0.066	0.061
Duchesne, UT	Yes (partial)	49-013-0002 (Roosevelt)	N/A	0.062	0.060	0.081
Uintah, UT	Yes (partial)	49-047-1002 (Dinosaur NM)	**0.068**	0.064	0.067	0.075
		49-047-1003 (Old Vernal)	N/A	0.062	N/A	N/A
		49-047-1004 (New Vernal)	N/A	N/A	0.064	0.073

The highest design value in each county is indicated in bold type.
N/A means that the monitor did not meet the completeness criteria described in 40 CFR, part 50, Appendix U, or no data exists for the county.

Table 7. Air Quality Data – Ute Indian Tribal Land (all values in ppm)

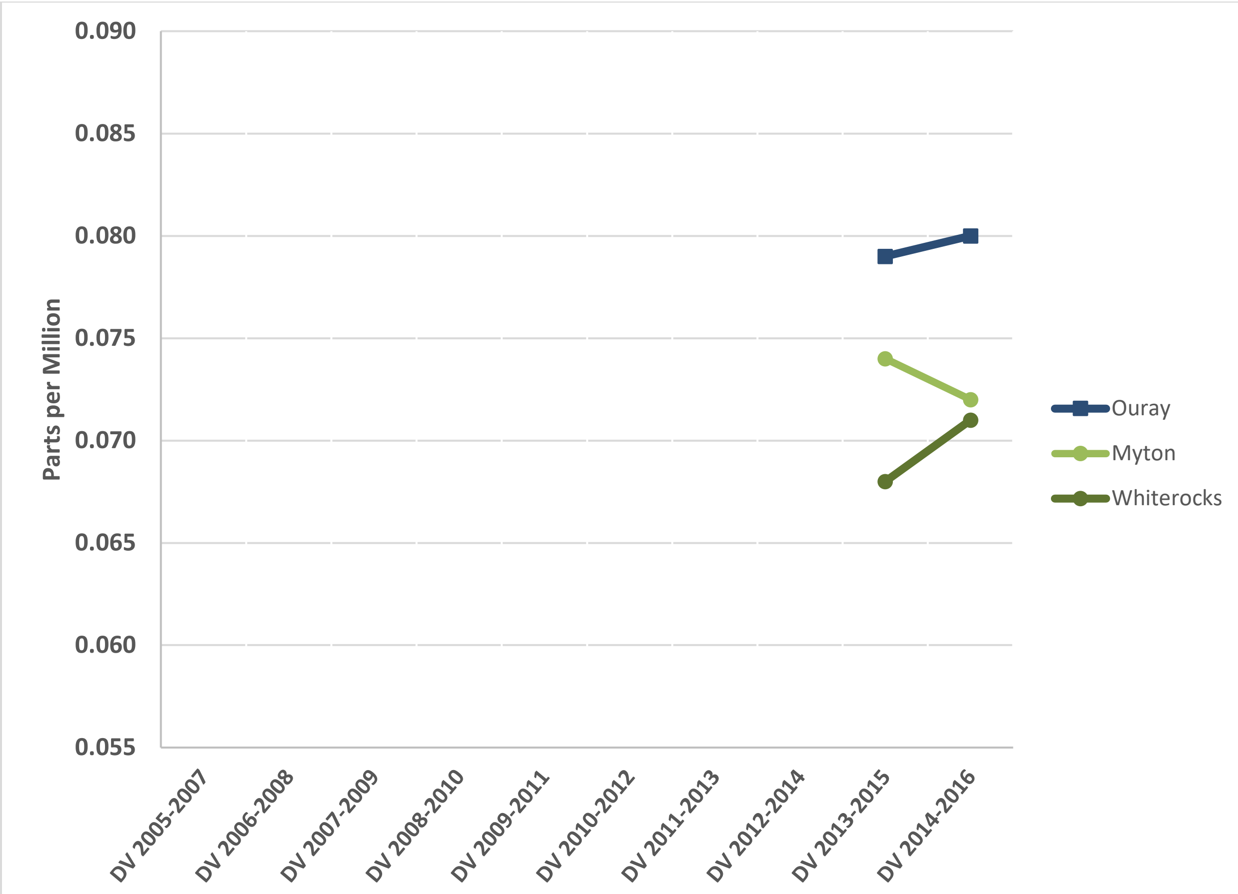
County, State	Tribe Recommended Nonattainment?	AQS Site ID	2014-2016 DV	2014 4th highest daily max value	2015 4th highest daily max value	2016 4th highest daily max value
Duchesne, UT	No	49-013-7011 (Myton)	**0.072**	0.067	0.065	0.085
Uintah, UT	No (or partial)	49-047-2002 (Redwash)	N/A	0.061	0.066	0.083
		49-047-2003 (Ouray)	**0.080**	0.079	0.067	0.096
		49-047-7022 (Whiterocks)	0.071	0.064	0.068	0.081

The highest design value in each county is indicated in bold type.
N/A means that the monitor did not meet the completeness criteria described in 40 CFR, part 50, Appendix U, or no data exists for the county.

Monitors within Uintah and Duchesne Counties on tribal land show violations of the 2015 ozone NAAQS; therefore, these counties with violating monitors are included in whole or in part in the final nonattainment area. The Rangely monitor in Rio Blanco County is well below the NAAQS with a design value of 0.063 ppm.

Figure 14, shown previously, identifies the Uinta Basin final nonattainment area and the violating monitors. Tables 6 and 7 identify the design values for all monitors in the area of analysis and Figure 15 shows the historical trend of design values for the violating monitors. Regulatory data collection in the Uinta Basin has only occurred since 2011. As indicated on the map, there are three violating monitors that are located at 1) the Myton site in Duchesne County, about six miles west of the community of Myton; 2) the Ouray site in Uintah County near the confluence of the Green and White Rivers, about 24 miles southeast of the town of Roosevelt; and 3) the Whiterocks site in Uintah County, twenty miles west of the town of Vernal and 1.5 miles northeast of the community of Whiterocks. Other monitors within Uintah and Duchesne Counties have incomplete data for 2014-2016, so the EPA cannot calculate valid design values in accordance with 40 CFR part 50, appendix U.

Figure 15. Three-Year Design Values for Uinta Basin Monitors (2007-2016)



Regulatory ozone measurements showing recurring exceedances have been conducted at two monitoring sites above 6,000 feet in the Uinta Basin. The Whiterocks monitoring station of the Ute Indian Tribe of the Uintah and Ouray Reservation is at an elevation of 6,216 feet,[17] and the Rabbit Mountain/Dragon Road Prevention of Significant Deterioration (PSD) monitoring station operated by ENEFIT was at an elevation of 6,165 feet. Both have recorded exceedances of the 70 ppb ozone standard. Whiterocks recorded two exceedances in 2011 and thirteen exceedances in 2013 prior to becoming a regulatory monitor (highest recorded 8-hour average was 107 ppb on January 22, 2013). Whiterocks then recorded four regulatory exceedances in December 2013, and seven in February 2016 (highest regulatory value 86 ppb on February 12, 2016) leading to a NAAQS violation. The Rabbit Mountain/Dragon Road monitor was a regulatory PSD monitor that operated throughout 2012 and for the first half of 2013. It recorded five non-winter ozone exceedances in April-August 2012 (with a highest value of 77 ppb), and 11 exceedances in January and

[17] Monitor site data in the AQS database shows an elevation of 1,893 meters, or 6,211 feet. Examination of the station siting on GIS maps gives an elevation of 6,216 feet.

February of 2013 (with a high of 107 ppb on January 26, 2013). An additional exceedance was recorded in May of 2013.

Based on the EPA's review of regulatory monitors in the Uinta Basin, the data shows that an elevation of 6,000 feet does not include all portions of the area violating the NAAQS and based on EPA's analysis here, it does not include all of the portions of the area contributing to violations of the NAAQS. Thus, it is not a practical upper boundary for the Uinta Basin ozone nonattainment area. Table 8 shows the elevation of the regulatory monitors in the Uinta basin, with summaries of their ozone measurements during the 2013 winter ozone study in the basin.[18] The elevation of the highest monitor is 6,216 feet.

Table 8. Winter 2013 Ozone Monitors

Site Name	Latitude	Longitude	Elevation	Number of Daily Winter 2013 Values over 70 ppb	Winter 2013 4th High (ppb)
Dinosaur N. M.	40.4372	-109.3047	1463 m (4,800 ft)	34	113
Ouray	40.05671	-109.688108	1467 m (4,813 ft)	39	132
Myton	40.216779	-110.182742	1606 m (5,269 ft)	27	97
Roosevelt	40.2942178	-110.009732	1596 m (5,236 ft)	32	104
Vernal	40.452267	-109.510393	1605 m (5,265 ft)	23	102
Rangely, CO	40.086944	-108.761389	1655 m (5,430 ft)	13	91
Redwash	40.206291	-109.353932	1702 m (5,584 ft)	36	114
Rabbit Mountain	39.868622	-109.097302	1879 m (6,165 ft)	11	82
Whiterocks	40.483598	-109.906796	1895 m (6,216 ft)[19]	13	86

Unlike most areas where photochemical ozone production is a summertime phenomenon, the Uinta Basin is a winter ozone area. For 2013-2015, regulatory monitors in the Uinta Basin recorded 54 days above the level of the 2015 NAAQS in the months of December through March, and only four days above that level in other months (including June 8-9, 2015 mentioned earlier as stratospheric intrusion exceptional event days). For 2014-2016, regulatory monitors recorded 19 days above the standard December through March, and

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[18] Final Report, 2013 Uinta Basin Winter Ozone Study, March 2014, ENVIRON (ed.), Section 8, Tethered Ozonesonde and Surface Ozone Measurements in the Uinta Basin, Winter 2013, p. 8-46; available in the docket for this action.
[19] Latitude, longitude and elevation are as shown in the AQS database with the exception of the elevation of the Whiterocks station, which is taken from digital map data.

only those two days in June 2015 were above the standard in other months. The causes of winter ozone formation will be discussed under factor 3 (Meteorology). Overall, the air quality data support designating all or portions of Duchesne and Uintah County (including tribal lands) as nonattainment of the 2015 ozone NAAQS.

Factor 2: Emissions and Emissions-Related Data

The EPA evaluated ozone precursor emissions of nitrogen oxides (NO_x) and volatile organic compounds (VOC) and other emissions-related data that provide information on areas contributing to violating monitors.

Emissions Data

The EPA reviewed data from the 2014 National Emissions Inventory (NEI). For each county in the area of analysis, the EPA examined the magnitude of large sources (NO_x or VOC emissions greater than 100 tons per year) and small point sources and the magnitude of county-level emissions reported in the NEI. These county-level emissions represent the sum of emissions from the following general source categories: point sources, non-point (i.e., area) sources, non-road mobile, on-road mobile, and fires. Emissions levels from sources in a nearby area indicate the potential for the area to contribute to monitored violations.

Table 9 provides a county-level emissions summary of NO_x and VOC (given in tons per year (tpy)) emissions for the area of analysis considered for inclusion in the final Uinta Basin nonattainment area. As shown in the table, Uintah County contributes the majority of VOC emissions – approximately 58% of the area of analysis. Duchesne County contributes approximately 36% of the total, while Rio Blanco's county-wide VOC emissions account for about 6% of the area-wide VOC emissions. Uintah and Duchesne Counties each contribute similar amounts to the NOx emissions in the area while Rio Blanco in Colorado contributes roughly 2,500 tpy less than either of the Utah Counties.

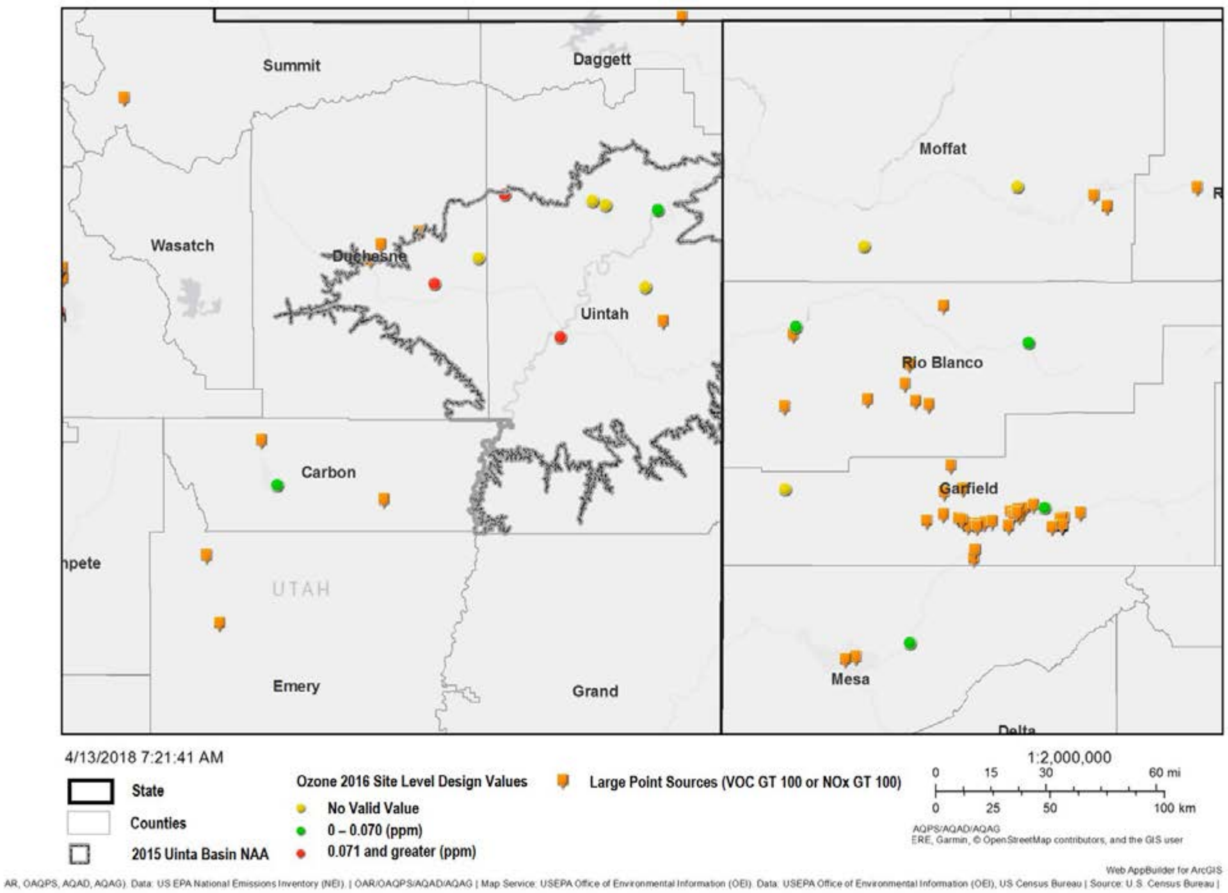
Table 9. Total County-Level NOx and VOC Emissions.

County	State Recommended Nonattainment	Total NOx (tpy)	Total VOC (tpy)
Duchesne	Yes (partial)*	9,352	55,880
Uintah	Yes (partial)*	9,116	88,592
Rio Blanco	No	6,746	9,330
	Area Wide:	25,214	153,802

* For state recommended partial counties, the emissions shown are for the entire county.

In addition to reviewing county-wide emissions of NO_x and VOC in the area of analysis, the EPA also reviewed emissions from large point sources. The location of these sources, together with the other factors, can help inform nonattainment boundaries. The locations of the large point sources are shown in Figure 16 below. In Utah, two of the four large point sources (natural gas compressor stations around Altamont in Duchesne County) are located outside the boundary initially recommended by the State, which includes only townships below 6,000-ft elevation. A third compressor station near Altamont is between 6,000 and 6,250 feet. Two other large sources are within the state-recommended boundary: a compressor station at 5,870 feet; and the Bonanza power station at 5,935 feet elevation on Indian country in Uintah County. The final nonattainment 6,250-ft elevation contour boundary is also shown in Figure 16. This boundary includes 3 of the 4 large point sources in Uintah and Duchesne counties. The one large point source that is outside the boundary (Altamont West Compressor Station) in Duchesne County accounts for 3% of the Duchesne county-level NOx and less than 1% of the county-level VOC emissions. In Colorado, there are two large point sources in the western portion of Rio Blanco county which could be considered to be within the Uinta Basin (a compressor station and an oil and gas processing facility). These two facilities contribute approximately 9% and 1% of the Rio Blanco county-level NOx and VOC emissions, respectively.

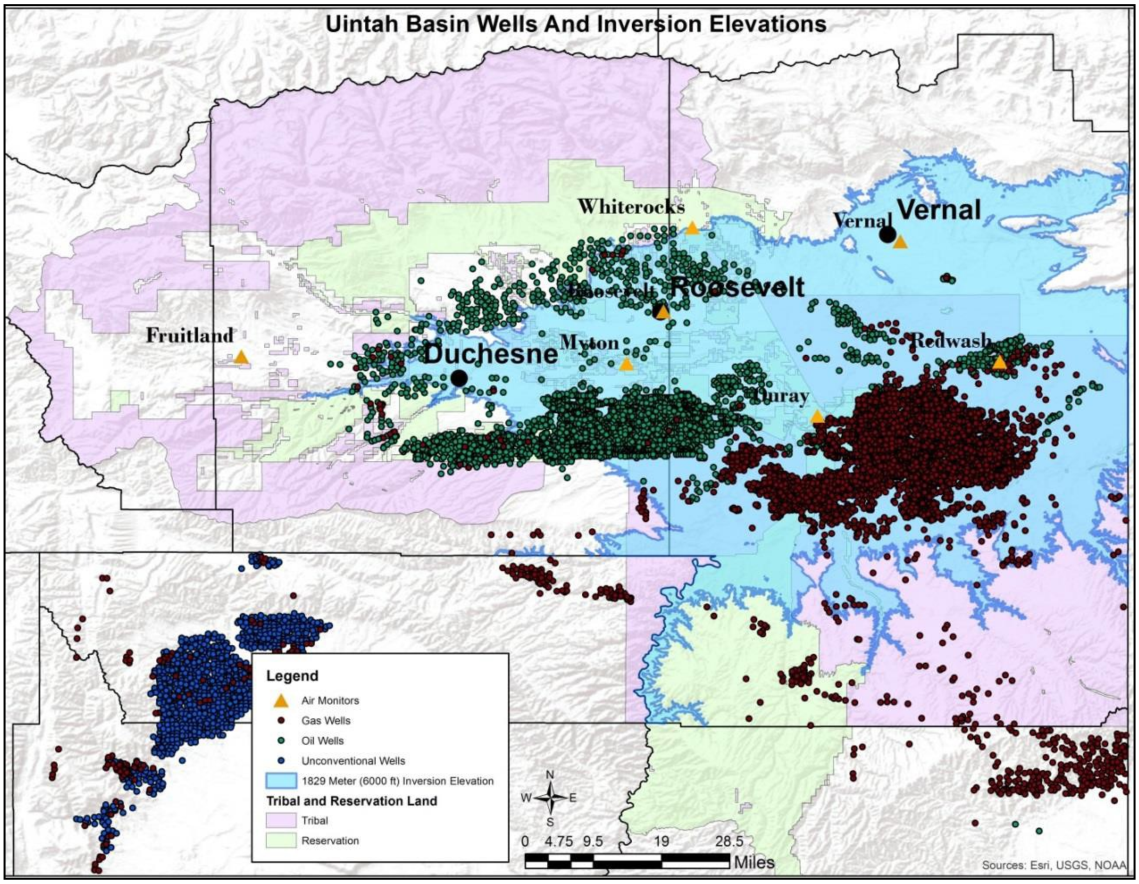
Figure 16. Large Point Sources in the Area of Analysis



In addition to looking at total overall emissions and large point source emissions for the county, we also reviewed the VOC and NO_X emissions by source sector in the Uinta Basin from the 2014 National Emissions Inventory, which shows that emissions from the production segment of the oil and natural gas sector were estimated to be the largest anthropogenic contributor of VOC and NO_X emissions in the area of analysis. These sources are located on both state and tribal land. As indicated by Utah in their TSD, approximately 80 percent of oil and gas production occurs on tribal land. As shown in Figure 17 (from Utah's TSD), oil and gas development is prevalent in most of central and southern Uintah County. In Duchesne County, oil and gas development has occurred mostly in the eastern 2/3 of the county. For both Uintah and Duchesne Counties, the northern portions of the counties are undeveloped and lack any significant emission sources; and include large areas of U. S. Forest Service land.

While most of these sources are located at the lower elevations in the basin, based on the information in the 2014 Uinta Basin Emissions Inventory[20] (included in Version 2 of the 2014 NEI), 84 percent of facilities representing 88 percent of emissions in Uintah and Duchesne Counties are below 6,000 ft in elevation. Additionally, 88 percent of all wells and 92 percent of all oil and natural gas emissions are below 6,250 ft in elevation.

Figure 17. Uinta Basin oil and gas wells and the State-recommended 6,000-ft elevation (blue)



Population density and degree of urbanization

In this part of the factor analysis, the EPA evaluated the population and vehicle use characteristics and trends of the area as indicators of the probable location and magnitude of non-point source emissions. These include emissions of NO_x and VOC from on-road and non-road vehicles and engines, consumer products, residential fuel combustion, and consumer services. Areas of dense population or commercial development are an indicator of area source and mobile source NO_x and VOC emissions that may contribute to violations of the NAAQS. Table 10 shows the population, population density, and population growth information for each county in the area of analysis.

[20] Emissions information was obtained from the 2014 Uinta Basin Emissions Inventory for all sources located below 6,250 ft.

Table 10. Population and Growth

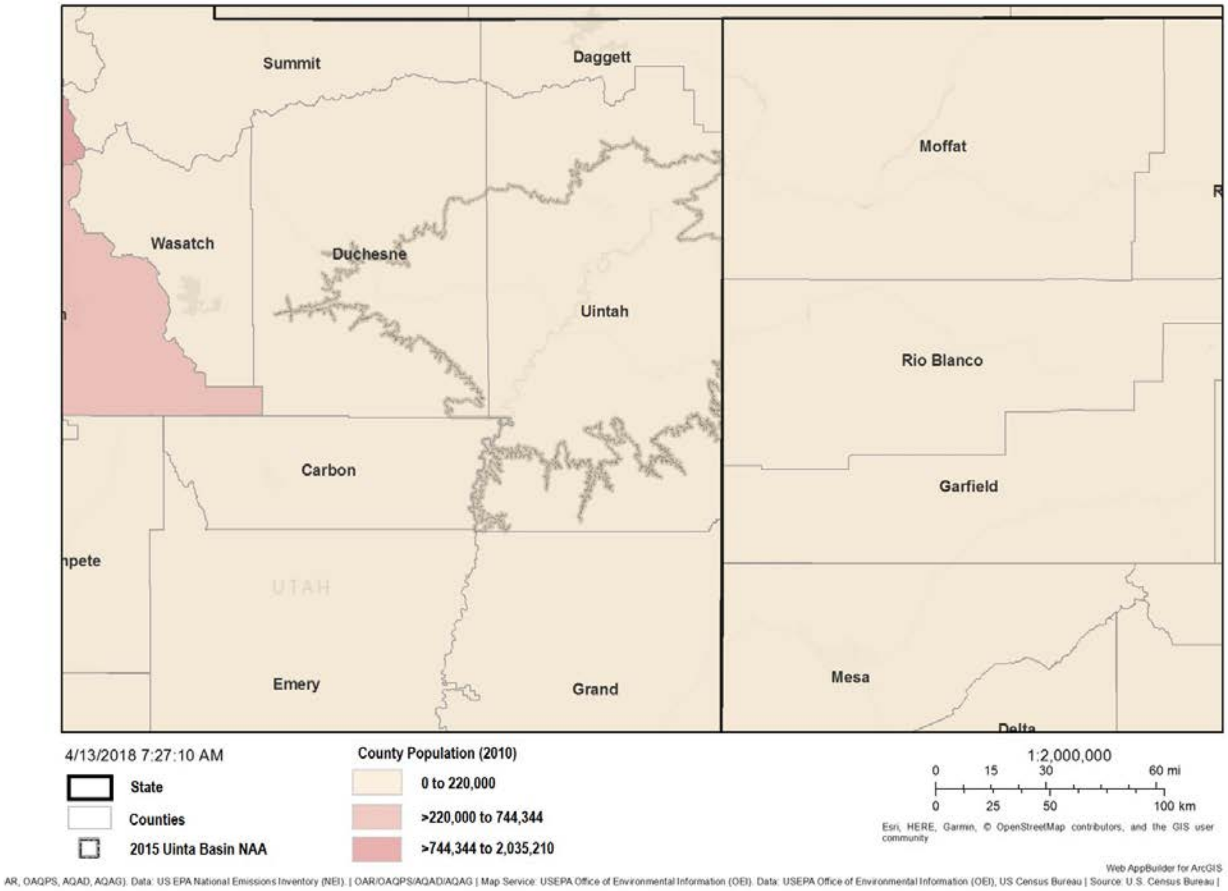
County Name	State Recommended Nonattainment	2010 Population	2015 Population	2015 Populations Density (per sq. mi.)	Absolute Change in Population (2010-2015)	Population % Change (2010-2015)
Uintah County	Yes (partial)*	32,588	37,928	8	5,340	16
Duchesne County	Yes (partial)*	18,607	20,862	6	2,255	12
Rio Blanco	No	6,666	6,571	2	-95	-1

* For state recommended partial counties, the data are for the entire county.

Source: U.S. Census Bureau population estimates for 2010 and 2015. www.census.gov/data.html.

The Uinta Basin is predominantly rural and contains a sparse population (see Figure 18). Although there has been a significant population change for Uintah and Duchesne counties, because of the sparse population, the absolute change in population is relatively small. Rio Blanco County has seen a one percent decline in population between 2010 and 2015. Most of the largest population centers are in the basin at the lower elevations: Myton, Roosevelt, Duchesne, Fort Duchesne, and Rangely.

Figure 18. County-Level Population



__Traffic and Vehicle Miles Travelled (VMT)__

The EPA evaluated the commuting patterns of residents, as well as the total vehicle miles traveled (VMT) for the area of analysis. In combination with the population/population density data and the location of main transportation arteries, this information helps identify the probable location of non-point source emissions. A county with high VMT and/or a high number of commuters is generally an integral part of an urban area and high VMT and/or high number of commuters indicates the presence of motor vehicle emissions that may contribute to violations of the NAAQS. Rapid population or VMT growth in a county on the urban perimeter may signify increasing integration with the core urban area, and thus could indicate that the associated area source and mobile source emissions may be appropriate to include in the nonattainment area. In addition to VMT, the EPA evaluated worker data collected by the U.S. Census Bureau[21] for the counties in the area of analysis. Table 11 shows the traffic and commuting pattern data, including total VMT for each county in the area of analysis, number of residents who work in each county, number of residents that work in counties with violating monitor(s), and the percent of residents working in counties with violating monitor(s). The data in Table 11 are from 2014.

[21] The worker data can be accessed at: http://onthemap.ces.census.gov/.

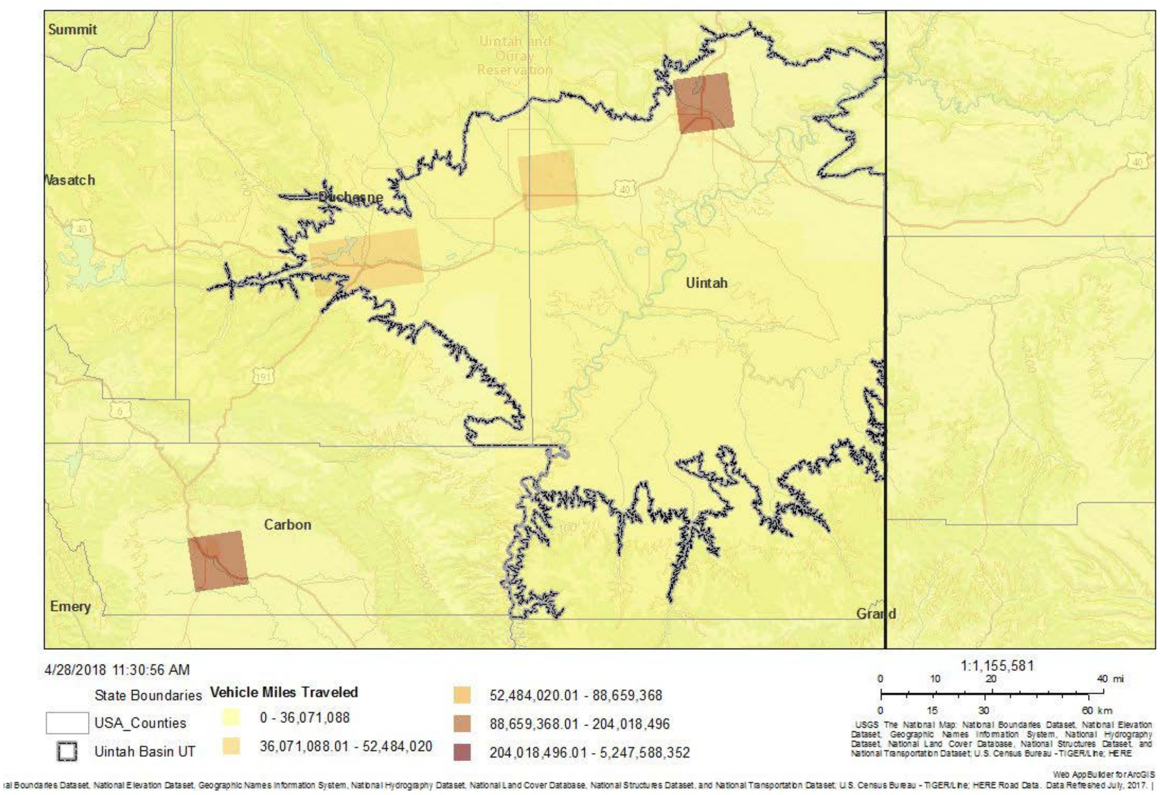
Table 11. Traffic and Commuting Patterns.

County	State Recommended Nonattainment?	2014 Total VMT (Million Miles)	Number of County Residents Who Work	Number Commuting to or Within Counties with Violating Monitor(s)	Percentage Commuting to or Within Counties with Violating Monitor(s)
Uintah	Yes (partial)*	428	16,723	11,710	70.0%
Duchesne	Yes (partial)*	283	8,981	5,789	64.5%
Rio Blanco	No	138	2,985	63	2.1%
	Total:	849	28,689	17,562	61.2

* For state recommended partial counties, the data provided are for the entire county.
Counties with a monitor(s) violating the NAAQS are indicated in bold.

To show traffic and commuting patterns, Figure 19 overlays twelve-kilometer gridded VMT from the 2014 NEI with a map of the transportation arteries.

Figure 19. Twelve Kilometer Gridded VMT (Miles) Overlaid with Transportation Arteries



As shown in Figure 19 and Table 11, commuting patterns and mobile source emissions are not large components of the VOC and NO_x emissions inventory (0.2 percent and 10 percent, respectively) in the basin and are consistent with the rural character of the region.

Factor 3: Meteorology

Evaluation of meteorological data helps to assess the fate and transport of emissions contributing to ozone concentrations and to identify areas potentially contributing to the monitored violations. Results of meteorological data analysis may inform the determination of nonattainment area boundaries.

The Uinta Basin winter meteorology combines with the basin's topography to create elevated ozone concentrations. The bowl-shaped basin is surrounded on each side by much larger mountain ranges with varying heights from over 7,500 to 13,000 feet. In environments such as this one, cooler, denser air becomes trapped in the basin when warmer air overrides the area during high pressure events. Subsidence from high pressure ridges and low surface winds in a stable environment do not allow for the normal atmospheric mixing (that would occur with positive lapse rates) during these events; only cooler temperatures aloft, high winds, or surface warming can break down an inversion and allow pollutants to mix out of the basin.

The ground level inversion in the Uinta Basin is persistent with snow cover. The sun's rays cannot reach the ground covered by snow to warm the surface. At night, cold, down sloping winds from the surrounding mountains can strengthen the inversion. The super-stable atmosphere allows emissions to accumulate, and the sunny conditions during the daytime let photochemical reactions take place. Only emissions with enough heat, plume velocity, or stack height can escape the inversion, depending on the boundary layer height, and enter the unstable atmosphere above the inversion. Many sources in the Uinta Basin emit VOC's with low heat, velocity, and stack heights, and a large portion of VOC emissions come from fugitive emissions and leaks. Taking into account atmospheric dispersion and turbulent flow plume dynamics for the majority of sources in the Uinta Basin, emissions do not have an opportunity to escape the boundary layer under the temperature inversion. Because of the meteorological factors that cause the boundary layer height to oscillate, and nighttime downslope winds, no static altitude of an inversion height throughout the basin always applies, and emissions above a given elevation can descend to lower elevations with nighttime orographic (downslope) flow.

Unique meteorological and topographic features result in the winter conditions that lead to ozone violations in the Uinta Basin. These unique features are strong and persistent temperature inversions forming over snow covered ground, elevated terrain completely surrounding a low basin, and abundant ground level emissions of ozone precursors from widely dispersed oil and gas production emission sources. Data from recent wintertime research campaigns was evaluated to determine how meteorology impacts the geographic extent of high ozone concentrations and the ability of emissions at a given elevation to migrate and produce ozone at other elevations (higher or lower than the emission point).

As noted in the Wasatch Front discussion, the HYSPLIT model is traditionally used to evaluate the impact of meteorology on sources and impacted monitors. However, in the case of the Uinta Basin, the complex metrological events that result in high ozone events are not well resolved by the synoptic-scale meteorological data used to produce HYSPLIT trajectories. Uinta Basin winter ozone forms under strong, shallow temperature inversions. The strong temperature inversions decouple surface winds, which control movement of locally emitted ozone precursors and ozone from the regional meteorology present above the inversion level. These complex, local-scale meteorological events are better characterized by local-scale analyses than by synoptic-scale analyses. Consequently, to best represent the complex and unique meteorology of high ozone events in the Uinta Basin, the EPA relied on air quality studies completed in the

Uinta Basin to determine the effect of meteorology in determining an appropriate nonattainment area boundary, rather than on HYSPLIT trajectories.

Wintertime ozone is formed in cold periods, generally with snow cover and under clear skies. Utah described the impact of winter weather on ozone formation.[22]

> *The wintertime photochemical ozone production in the Basin requires snow on the ground, a shallow boundary layer, stagnation and a persistent temperature inversion capping the shallow ozone production layer. The snow helps to keep the surface cold, reinforcing the production and maintenance of the temperature inversion. Snow also reflects daytime solar radiation that enhances photochemical ozone production. The inversion layer traps the emissions from the wells, pipelines, and compressor stations in a shallow layer where the rapid photochemical ozone production occurs.*

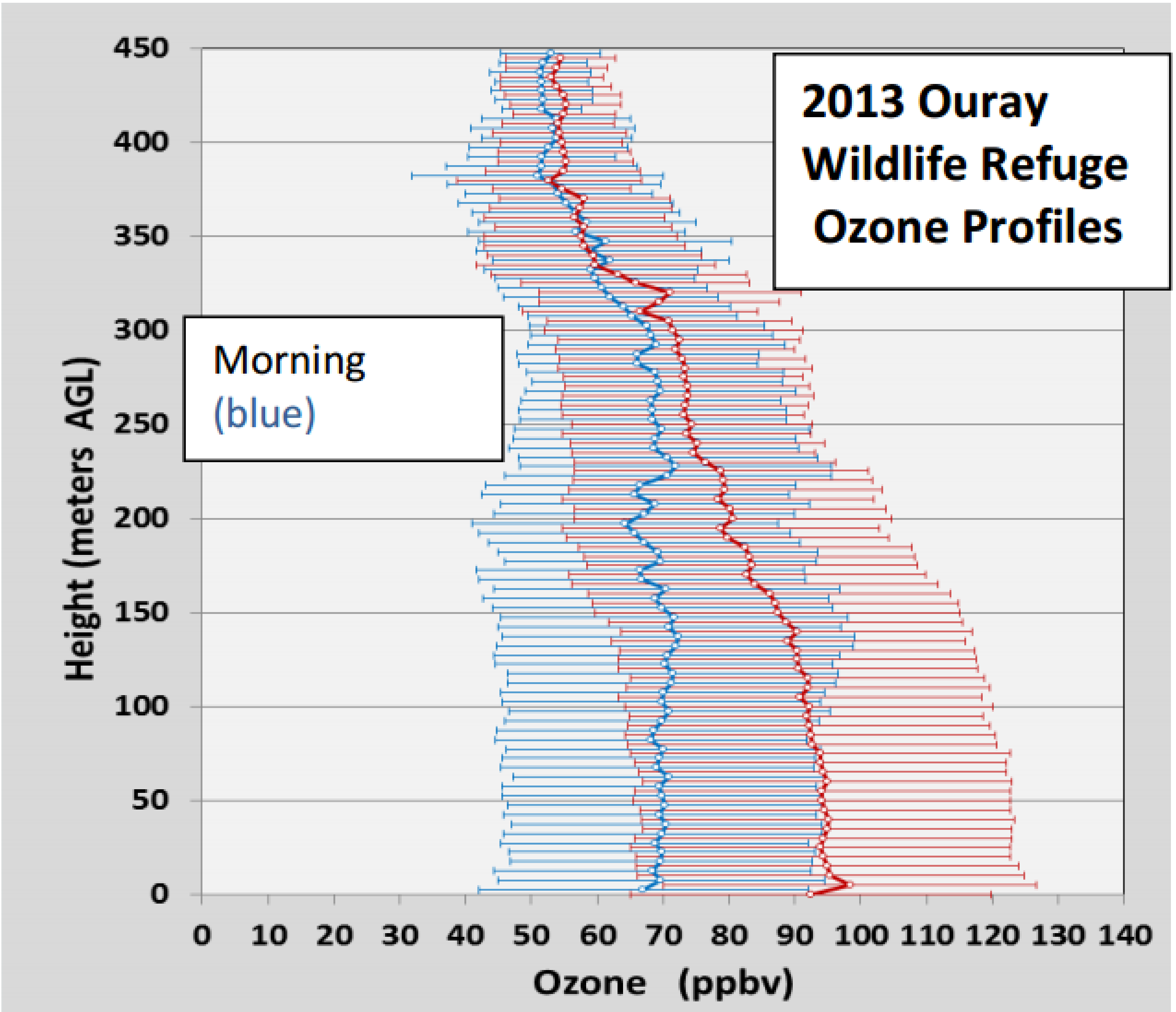
Utah bases its recommendation for an upper elevation limit on results from the 2013 Uinta Basin Winter Ozone Study.

> *This vertical limit to the high ozone and the chemistry that forms high ozone was observed at 1,700 meters (5,577 feet) during one of the strongest winter inversions studied and experienced the highest ozone values recorded (UBOS 2013*).

Ozonesondes were launched primarily from the Ouray National Wildlife Refuge, at 1,430-meter elevation (4,692 feet) and from Fantasy Canyon, at 1,470 meters (4,823 feet). A few sondes were launched from the Horsepool site, at 1,569 meters (5,148 feet). In general, the ozonesondes found surface ozone was elevated through the lower 300 meters (984 feet) of the atmosphere on high ozone days. Averages and extremes of ozone concentration as a function of ozonesonde height at the Ouray National Wildlife Refuge site from the 2013 winter study are shown in Figure 20.

[22] UT TSD, p. 48-49.

Figure 20. Summary plot of the 2013 average ozone mixing ratio and standard deviations measured at all sites during morning (between sunrise and local noon, in blue) and afternoon (noon to sunset, in red). Note the large range of ozone concentrations in 2013 and the large photochemical production of ozone in the afternoons.[23]

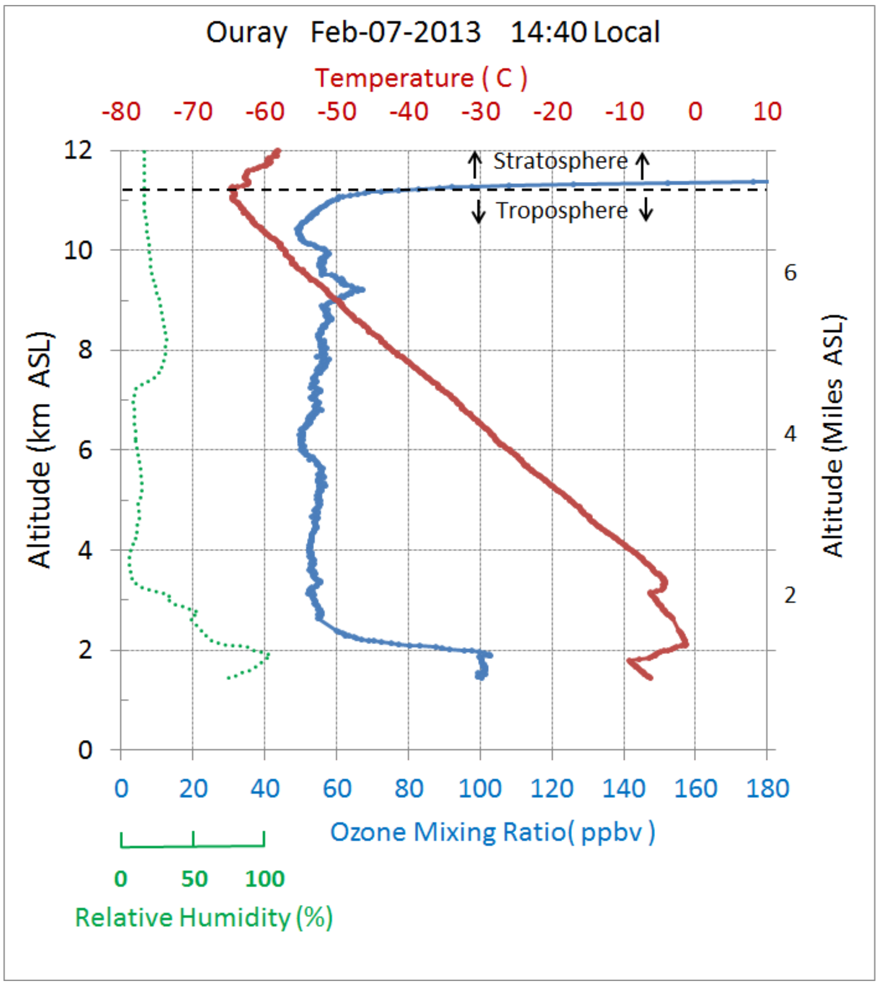


The dominant meteorological feature influencing the frequency and severity of ozone exceedances in the Uinta Basin are persistent wintertime temperature inversions. Figure 21 shows a typical ozonesonde sounding, from 2:40 pm on February 7, 2013 at the Ouray National Wildlife Refuge site (surface elevation of 1,430 m, or 4,692 feet). It shows a surface temperature of about -7 °C (19.4 °F), with temperature decreasing to about -9 °C (15.8 °F) at the top of the temperature inversion. Air temperature then increases above the top of the inversion layer to a high of about -2 °C (28.4 °F) at an altitude of about 2,100 m (6,890

[23] Final Report, 2013 Uinta Basin Winter Ozone Study, March 2014, ENVIRON (ed.), Section 8, Tethered Ozonesonde and Surface Ozone Measurements in the Uinta Basin, Winter 2013, p. 8-9; https://deq.utah.gov/locations/U/uintahbasin/ozone/docs/2014/06Jun/UBOS2013FinalReport/UBOS_2013Sec_8_NOAAsondes.pdf.

feet). Above that peak temperature, temperatures decrease, until the surface temperature of -7 ° is reached again at an altitude of about 3,200 m (10,500 feet) at the base of a second weak temperature inversion. The temperature inversions, with colder air below warmer air, limit the vertical transport of pollutants, trapping pollutants below the inversion, and preventing transported pollutants above the inversion from mixing downward to the surface. The ozonesonde also shows elevated ozone at 100 ppb extending from the surface to the top of the surface temperature inversion at about 1,900 m (6,234 feet), and then shows well mixed tropospheric background ozone at 50 to 55 ppb from an altitude of 2,500 m (8,200 feet) to the tropopause at about 10,500 m (34,450 feet).

Figure 21. Free Flying Ozonesonde Data, Tropospheric Portion, Ouray, 2:40 pm MST, February 7, 2013[24]



The Whiterocks monitor, which is in violation of the ozone standard using 2014-2016 data, is a good indicator for transportation and meteorological factors that affect ozone readings at ground levels above

[24] NOAA Earth Systems Research Laboratory, Global Monitoring Division, Ozonesonde Archive, Field Projects, Uintah 2013, Ouray_Feb07_2013_FreeFlyingBalloon_Troposphere.png, ftp://ftp.cmdl.noaa.gov/ozwv/Ozonesonde/Field%20Projects/Uintah/UINTAH%202013/4_OzoneSonde_FreeFlight_Balloons/

6,000 feet. Because of the site location at the north of the basin, closer to the Uinta mountain range, a diurnal orographic wind pattern of upsloping winds during the daytime, and downslope winds at night are prevalent at this site. Establishing a partial county designation based on a 6,000 feet level is not supported by the data from the 6,216-ft Whiterocks monitor.

In Rio Blanco County, Colorado, along the White River valley, winds under winter temperature inversions are often light and variable. This means that winds speeds are extremely low (often under 1 mph) and sometimes do not show a consistent wind direction from hour to hour. On temperature inversion days when a consistent wind direction is seen, the wind pattern is a downvalley flow (from Colorado towards Utah) during nighttime hours, with a reversal to upvalley winds (from Utah toward Colorado) during daylight and evening hours. The EPA evaluated days in 2013-2016 where the Redwash monitor (the nearest Utah monitor to Rio Blanco County) exceeded the NAAQS. On those exceedance days with directional winds at the Rangely monitor in Rio Blanco County, winds were down-valley toward Utah generally from 1:00 am to about 8:00 am, and then up-valley, from Utah toward Colorado from about 10:00 am until midnight. Average down-valley winds at night were 1.6 mph, while average up-valley winds during the day and evening were 0.8 mph. Net transport for this diurnal pattern (8 hours at 1.6 mph followed by 14 hours in the opposite direction at 0.8 mph) is 1.6 miles of east to west transport per day. The nearest monitor in Utah to Rio Blanco County is the Redwash monitor. Redwash is 16 miles west of Rio Blanco County, and 20 miles west of the oil and gas emission sources in Rio Blanco County. Redwash, however, lacks complete data showing a 2014-2016 NAAQS violation. The nearest violating monitor to Rio Blanco County is the Ouray monitor, 34 miles west of Rio Blanco County, and 40 miles west of the Rio Blanco County emission sources.

Factor 4: Geography/topography

Consideration of geography or topography can provide additional information relevant to defining nonattainment area boundaries. Analyses should examine the physical features of the land that might define the airshed. Mountains or other physical features may influence the fate and transport of emissions as well as the formation and distribution of ozone concentrations. The absence of any such geographic or topographic features may also be a relevant consideration in selecting boundaries for a given area.

The EPA used geography/topography analysis to evaluate the physical features of the land that might affect the airshed and, therefore, the distribution of ozone over the area. Figure 22 shows the region of northern Utah which includes the Uinta Basin (primarily in Uintah and Duchesne Counties) and the small portion of the basin in western Rio Blanco County, Colorado. Figure 23, from the Utah designation recommendation[25] more clearly shows the topography of the basin and the physical features surrounding it. The Uinta Basin is entirely enclosed by higher level terrain on all sides which prevents transport of emissions into the basin from surrounding counties. The only low elevation breaks in the surrounding higher terrain are the incoming Green and White River Valleys (entering the basin at elevations of 4,800 and 5,600 feet, respectively) and the outlet to the south along the Green River (at 4,625 feet). Under wintertime temperature inversion conditions, cold air pools at the lower elevations in the basin, and pollutants are trapped in the pooled air under the temperature inversion. As long as snow cover is present, inversions can persist for periods longer than a week, until energetic weather systems break the temperature inversion and sweep out trapped pollutants. While trapping locally emitted pollutants under an inversion layer within the basin, the inversion

[25] UT TSD, p. 50.

layer also prevents transported pollutants from outside the basin from entering the basin and contributing to ozone formation, as warmer air aloft carrying upwind emissions tends to float across the colder air trapped below. As long as a temperature inversion is present, resulting in the coldest air lying at or near the surface, and with warmer air above the inversion, transported pollutants arriving aloft at higher temperatures than the surface are prevented from descending through the inversion layer and impacting the local photochemistry.

Figure 22. Topographic Illustration of the Physical Features

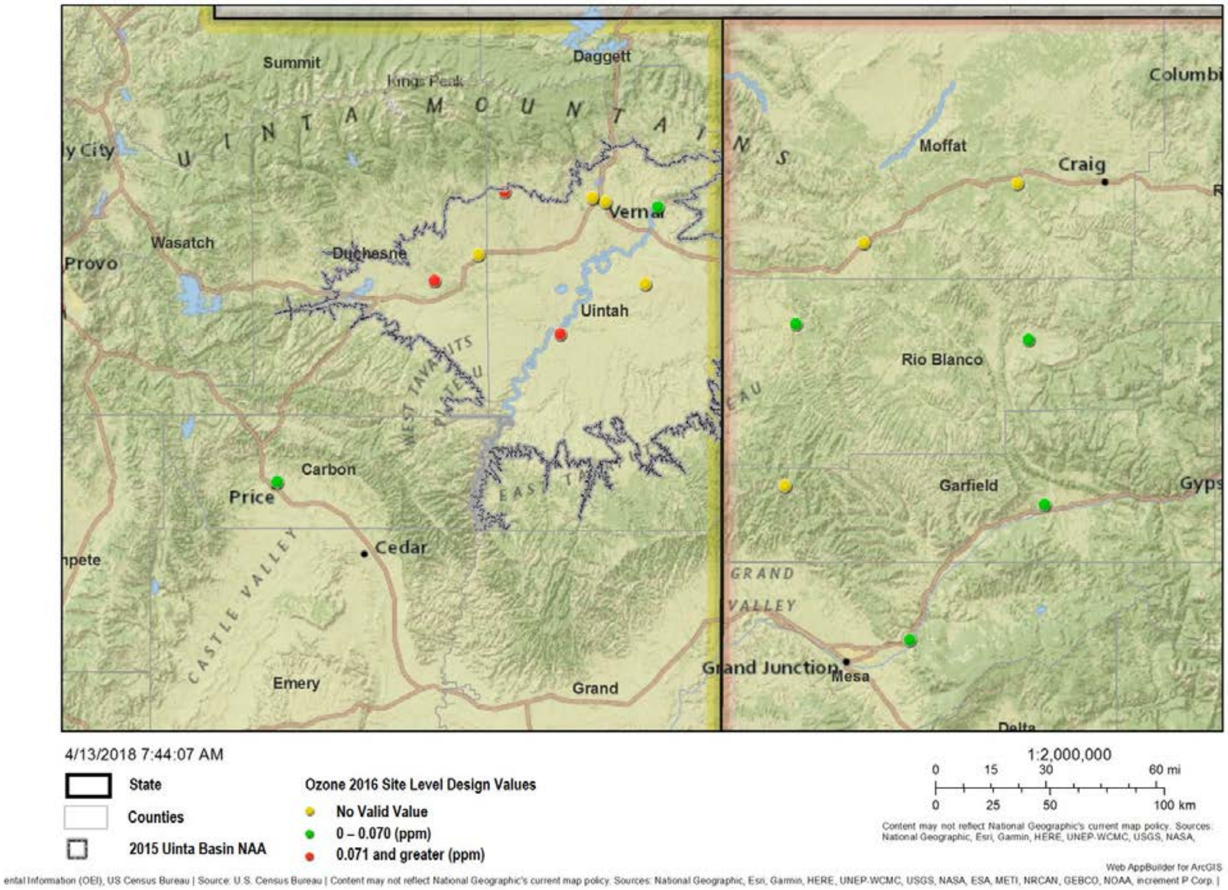
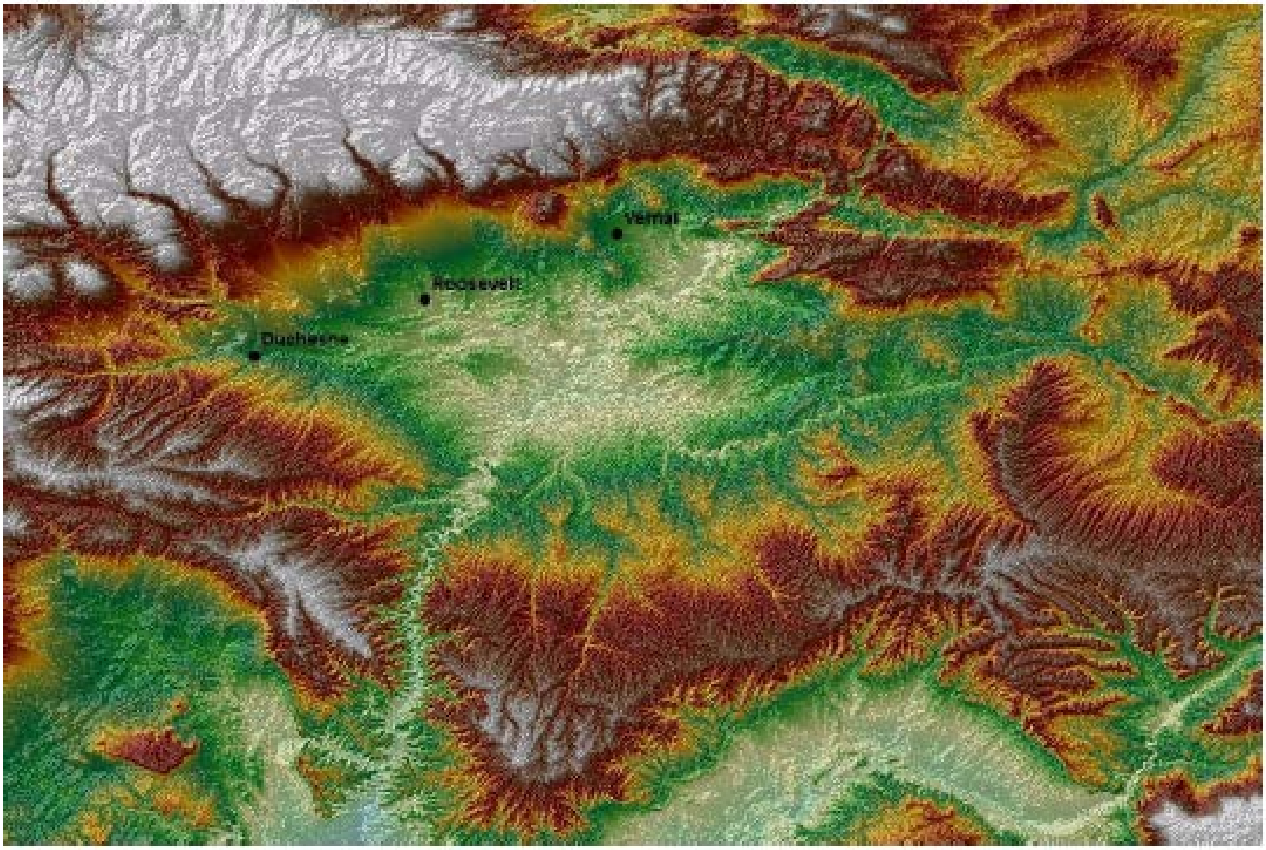


Figure 23. Topography of the Uinta Basin of Utah.



Factor 5: Jurisdictional boundaries

Once the geographic extent of the violating area and the nearby area contributing to violations is determined, the EPA considered existing jurisdictional boundaries for the purposes of providing a clearly defined legal boundary to carry out the air quality planning and enforcement functions for nonattainment areas. In defining the boundaries of the final Uinta Basin nonattainment area, the EPA considered existing jurisdictional boundaries, which can provide easily identifiable and recognized boundaries for purposes of implementing the NAAQS. Examples of jurisdictional boundaries include, but are not limited to: states, counties, air districts, areas of Indian country, metropolitan planning organizations, and existing nonattainment areas. If an existing jurisdictional boundary is used to help define the nonattainment area, it must encompass all of the area that has been identified as meeting the nonattainment definition. Where existing jurisdictional boundaries are not adequate or appropriate to describe the nonattainment area, the EPA considered other clearly defined and permanent landmarks or geographic coordinates for purposes of identifying the boundaries of the final designated areas.

The EPA evaluated the existing county jurisdictional boundaries in determining an appropriate nonattainment boundary for the Uinta Basin. For Uintah County, oil and gas development is prevalent throughout the county with the exception of the mountainous northern portion, and those sources contribute to violating monitors. For Duchesne County, significant oil and gas development has occurred in the eastern and southern portion of the county. However, much of the county to the west of the town of Duchesne does not have any oil and gas development or other sources of ozone precursors emissions that could contribute to violating monitors in the Uinta Basin. As noted earlier, for both Uintah and Duchesne Counties, the northern portions of the counties are undeveloped and include large areas of U. S. Forest Service land. For Rio Blanco County, emission sources lie within the Uinta Basin portion of the county, but are remote from violating monitors.

The Uinta Basin also includes portions of Indian country. As defined at 18 U.S.C. 1151, "Indian country" refers to: "(a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same." The EPA recognizes the sovereignty of tribal governments, and has attempted to take the input of the tribes into account in establishing appropriate nonattainment area boundaries.

As noted earlier, the Ute Indian Tribe provided the EPA with a recommendation of attainment for the entire tribal area within the Uinta Basin – assuming the EPA concurs on an exceptional events demonstration for two days in June 2015. If the EPA disagrees with the exceptional event package, the Ute Tribe requests that an unspecified area around the Ouray monitor be designated nonattainment. Regardless of whether there was an exceptional event on the two days in June 2015, the 2014-2016 monitoring data still shows violations at three tribal monitors within the basin. The Clean Air Act requires that any area containing a violating monitor must be designated nonattainment. The majority (80 percent) of oil and gas sources in the Uinta Basin are located on tribal land. As discussed earlier, when inversions occur and air is uniformly mixed below the inversion, sources throughout the basin contribute to violations at both state and tribal monitors.

Conclusion for Uinta Basin

The EPA is designating portions of Duchesne and Uintah Counties, including both state and tribal lands located in those portions of the county, as nonattainment for the 2015 ozone standard. The EPA is modifying the State's recommendation that the boundary for the nonattainment area be established at an elevation of 6,000 feet. The EPA is also modifying the recommendation provided by the Ute Tribe – specifically, the recommendation to designate an area of nonattainment only surrounding the Ouray monitor. Two other monitors at Whiterocks (Uintah County) and Myton (Duchesne County) are also measuring violations of the NAAQS and the tribe's recommended boundary would not include those violating monitors. VOC emissions from oil and gas sources are the primary contributors to elevated ozone in the Uinta Basin. As discussed in the five-factor analysis, these precursor emissions originate from oil and gas operations on both state and tribal land. Additionally, The EPA finds that designating townships below 6,000 feet, as proposed by Utah, does not sufficiently include all violating monitors and contributing sources. The Whiterocks regulatory monitor is measuring a 2016 design value in violation of the 2015 ozone NAAQS and is located at 6,216 ft. The EPA concludes that areas above 6,000 ft. are violating the NAAQS, and sources above 6,000 ft. are contributing to the formation of ozone in excess of the NAAQS. Based on Clean Air Act requirements, nonattainment boundaries must be defined to adequately capture all violating monitors. In December 2017, the EPA proposed modifying the State's recommendation to include all townships with at least 10 percent of land area below 6,250 ft. to ensure that the Whiterocks monitor is included in the nonattainment boundary. The EPA received several comments on the proposed boundary from the State, Ute Tribe, local governments, and industry suggesting that a more precise boundary is necessary and appropriate; and defining a boundary where all townships with greater than 10 percent of land area below 6,250 ft. would unnecessarily include land that does not have contributing sources and lies above the inversion during ozone events. As discussed in the air quality data, topography, and meteorology sections of this TSD, the EPA has determined that the inversion typically occurs at elevations at, and below 6,250 ft. during high ozone events. Based on analysis of these factors, the EPA has determined that modifying the proposed boundary to be based on elevation, as suggested by many of the commenters, is appropriate. The EPA is finalizing a boundary that includes all areas in Uintah and Duchesne Counties below the 6,250 ft. elevation contour. This boundary includes 88 percent of all oil and natural gas wells and 92 percent[26] of all oil and natural gas emissions, most major sources and populated areas, and all violating monitors. The boundary was drawn (as shown in Figure 14) to trace a contour line at 6,250 ft. around the Uinta Basin, within Uintah and Duchesne Counties. To avoid nonattainment and attainment “islands,” all areas within that external perimeter are included in the nonattainment area – including mesas and buttes which may have an elevation greater than 6,250 ft. but which are surrounded on all sides by land lower than 6,250 ft. Additionally, there are areas that fall outside the 6,250 ft. external perimeter that have elevations less than 6,250 ft.; these areas are excluded from the nonattainment area.

Although a portion of Rio Blanco County is within the Uinta Basin – and below 6,250 ft., the EPA is not including it in the nonattainment area and is designating all of Rio Blanco County as attainment/unclassifiable for the 2015 ozone NAAQS. As provided above, the emissions in Rio Blanco County are small in comparison to the emissions from oil and gas operations in the two Utah Counties and on tribal land, and it is those emissions that are driving the unique wintertime ozone violations in area. In addition, Rio Blanco County emissions sources are located far from violating monitors, and the extremely low transport wind speeds recorded in Rangely, Colorado, show insufficient transport to violating monitors to allow these emissions to contribute to violations.

[26] Emissions information was obtained from the 2014 Uinta Basin Emissions Inventory for all sources located below 6,250 ft.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

**CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS
(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)**

5 CCR 1001-9

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

Outline of Regulation

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IV. Control of Emissions from Breweries in the 8-hour Ozone Control Area

PART F Statements of Basis, Specific Statutory Authority and Purpose

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Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.govinfo.gov. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

PART A Applicability and General Provisions

I. Applicability

I.A.

I.A.1. The provisions of this regulation shall apply as follows:

I.A.1.a. All provisions of this regulation apply to the Denver 1-hour ozone attainment/maintenance area, to any nonattainment area for the 1-hour ozone standard, and to the 8-hour Ozone Control Area.

I.A.1.b. (State Only) All provisions of this regulation apply to any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Section I.A.1.c. Colorado's ozone nonattainment or attainment maintenance area maps and chronologies of attainment status are identified in Appendix A of this regulation.

I.A.1.c. The provisions of Part B, Sections III., IV.B.1. and 2., V.C., and Part D, Sections II., III., IV., and V. apply statewide. The provisions of Part D, Sections II., III., and any other sections marked by (State Only) are not federally enforceable, unless otherwise identified.

I.A.2. REPEALED

I.A.3. REPEALED

I.B. Sources

I.B.1. New Sources

I.B.1.a. New sources, defined as any sources which either (1) submit a complete permit application on or after October 30, 1989, or (2) if no permit is required, commence operation on or after October 30, 1989, must comply with the provisions of this regulation upon commencement of operation.

I.B.1.b. (State Only) New sources are any sources which commenced construction on or after the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989. New sources shall comply with the requirements of this regulation by whichever date comes later:

I.B.1.b.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.1.b.(ii) (State Only) February 1, 2009, if they are located in an 8-Hour Ozone Control Area and outside of the 1-hour ozone nonattainment or attainment maintenance area; or

I.B.1.b.(iii) (State Only) Upon commencement of operation, if located within an ozone nonattainment or attainment maintenance area.

I.B.1.c. This Section I.B.1. does not apply to oil and gas operations subject to Part D, Section I., stationary and portable engines subject to Part E, Section I.A. through C., or natural gas actuated pneumatic controllers subject to Part D, Section III.

I.B.2. Existing Sources

I.B.2.a. Existing sources are (1) those sources for which a complete permit application was submitted prior to October 30, 1989, or (2) those sources, which commenced operation prior to October 30, 1989.

I.B.2.b. (State Only) Existing sources are those sources which commenced construction prior to the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989.

I.B.2.c. Existing sources shall not be required to comply with requirements of this regulation until on and after October 30, 1991. All existing sources shall comply with the requirements set forth in Exhibit A until October 30, 1991.

I.B.2.d. (State Only) Existing sources shall be required to comply with requirements of this regulation by whichever date comes later:

I.B.2.d.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.2.d.(ii) (State Only) February 1, 2009, if they are located in an 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area; or

I.B.2.d.(iii) (State Only) the date on which the area is first designated as being in nonattainment for ozone, if located within that ozone nonattainment or attainment maintenance area.

I.B.2.e. On and after October 30, 1991, all existing sources shall comply with the requirements of this regulation, and Exhibit A shall no longer be applicable.

I.B.2.f. Repealed.

I.B.2.g. Repealed.

I.B.2.h. This Section I.B.2. does not apply to oil and gas operations subject to Part D, Section I., or stationary and portable engines subject to Part E, Section I.A. through C.

I.C. Once a source subject to this regulation exceeds an applicable threshold limit, the requirements of this regulation are irrevocably effective unless the source obtains a federally enforceable permit limiting emissions to levels below the threshold limit by restricting production capacity or hours of operation.

I.D. The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II. General Provisions

II.A. Definitions

II.A.1. "8-Hour Ozone Control Area" means the Counties of Adams, Arapahoe, Boulder (includes part of Rocky Mountain National Park), Douglas, and Jefferson; the Cities and Counties of Denver and Broomfield; and the following portions of the Counties of Larimer and Weld:

II.A.1.a. For Larimer County (includes part of Rocky Mountain National Park), that portion of the county that lies south of a line described as follows: Beginning at a point on Larimer County's eastern boundary and Weld County's western boundary intersected by 40 degrees, 42 minutes, and 47.1 seconds north latitude, proceed west to a point defined by the intersection of 40 degrees, 42 minutes, 47.1 seconds north latitude and 105 degrees, 29 minutes, and 40.0 seconds west longitude, thence proceed south on 105 degrees, 29 minutes, 40.0 seconds west longitude to the intersection with 40 degrees, 33 minutes and 17.4 seconds north latitude, thence proceed west on 40 degrees, 33 minutes, 17.4 seconds north latitude until this line intersects Larimer County's western boundary and Grand County's eastern boundary.

II.A.1.b. For Weld County, that portion of the county that lies south of a line described as follows: Beginning at a point on Weld County's eastern boundary and Logan County's western boundary intersected by 40 degrees, 42 minutes, 47.1 seconds north latitude, proceed west on 40 degrees, 42 minutes, 47.1 seconds north latitude until this line intersects Weld County's western boundary and Larimer County's eastern boundary.

II.A.2. "Denver 1-Hour Ozone Attainment/Maintenance Area" means the Counties of Jefferson and Douglas, the Cities and Counties of Denver and Broomfield, Boulder County (excluding Rocky Mountain National Park), Adams County west of Kiowa Creek, and Arapahoe County west of Kiowa Creek.

II.A.3. "Capture System" means the equipment used to contain, capture, or transport a pollutant to a control device.

II.A.4. "Capture System Efficiency (vapor gathering system efficiency)" means the percent by weight of VOC emitted by an operation subject to this regulation, which is captured by the capture system and sent to the control device; i.e., (mass flow of VOC captured)/(mass flow of VOC emitted by the operation) x 100%.

II.A.5. "Carbon Adsorption System" means a device containing adsorbent material, an inlet and outlet for exhaust gases and a system to regenerate the saturated adsorbent.

II.A.6. "Condenser" means any heat transfer device used to liquefy vapors by removing their latent heats of vaporization. Such devices include, but are not limited to, shell and tube, coil, surface, or contact condensers.

II.A.7. "Control Device" means a carbon adsorber, refrigeration system, condenser, flare, firebox or other device, which will reduce the concentration of VOC in a gas stream by adsorption, combustion, condensation, or other means of removal.

II.A.8. "Control Device Efficiency" means the percent removal by weight of VOC by a control device; i.e., (mass flow of VOC into control device - mass flow of VOC out of control device)/(mass flow of VOC into control device) x 100%.

II.A.9. "Gasoline" means a petroleum distillate having a Reid vapor pressure between 208 and 1040 torr (4-20 psi), which is used as fuel for internal combustion engines.

II.A.10. "Highly Volatile Organic Compound" is defined as a Volatile Organic Compound or mixture of such compounds with a true vapor pressure in excess of 570 torr (11 psia) at 20 C.

II.A.11. “Organic Material” means a chemical compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.

II.A.12. (State Only) “Ozone Nonattainment Area” means any area designated as not in attainment with the ozone National Ambient Air Quality Standard as determined by the Environmental Protection Agency.

II.A.13. “Petroleum Refinery” means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

II.A.14. “Reid Vapor Pressure” means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquefied petroleum gases as determined by the American Society for Testing and Materials, Part 17, 1973, D-323-72 (Reapproved 1977).

II.A.15. “True Vapor Pressure” means the equilibrium partial pressure exerted by petroleum (or other) liquid. This may be determined by the methods described in American Petroleum Institute Bulletin 2517, “Evaporation Loss from Floating Roof Tanks,” 1962.

II.A.16. “Vapor Recovery System” means a system that prevents release to the atmosphere of organic compounds emitted during the operation of any transfer, storage, or processing equipment.

II.A.17. "Volatile Organic Compound (VOC)" means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions, except those listed in Section II.B. as having negligible photochemical reactivity. VOC may be measured by a reference method, an equivalent method, an alternative method, or by procedures specified under 40 CFR Part 60 (September 14, 1989). A reference method, an equivalent method, or an alternative method, however, may also measure nonreactive organic compounds. In such cases, an owner or operator may exclude the compounds listed in Section II.B. when determining compliance with a standard if the amount of such compounds is accurately quantified, and such exclusion is approved by the Division. As a precondition to excluding such compounds as VOC, or at any time thereafter, the Division may require an owner or operator to provide monitoring or testing methods and results demonstrating, to the satisfaction of the Division, the amount of negligible-reactive compounds in the source's emissions.

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation. However, the hydrocarbon threshold in Part D, Section I.L. and natural gas emissions standards in Part D, Sections III.C.1. and III.C.2. are used as indicators for the volatile organic compound emission reduction measures in Part D, Sections I.L., III.C.1., and III.C.2., and are enforceable provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Part D.

II.C. General Emission Limitation

II.C.1. Existing Sources (State Only: Located in any Ozone Nonattainment Area or Attainment Maintenance Area)

II.C.1.a. All existing sources shall comply with the requirements set forth in this regulation.

II.C.1.a.(i) Existing sources of VOC which are not subject to specific emission limitations set forth in this regulation, and which have the potential to emit 100 tons per year or more of VOC, shall utilize Reasonably Available Control Technology (RACT).

II.C.1.a.(ii) The potential to emit of such sources shall be based on design capacity or maximum production rate, whichever is greater, 8,760 hours'/year operation, and before add-on controls.

II.C.1.a.(iii) Owners or operators of such sources with potential emissions of 100 tons per year or more, but with actual emissions less than 100 tons per year may obtain a federally enforceable permit limiting emissions to actual rates by restricting production capacity or hours of operation, thus avoiding RACT requirements.

The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II.C.1.a.(iv) Such sources with potential emissions of 100 tons per year or more but with actual emissions of less than 50 tons per year, on a rolling 12-month total, may avoid RACT and permit requirements if the following requirements are met:

II.C.1.a.(iv)(A) The owner or operator shall submit revised Air Pollutant Emission Notices (APENs) by April 1 of each year, which demonstrate that the 50 tons per year threshold has not been exceeded.

II.C.1.a.(iv)(B) The owner or operator shall maintain records on site which include monthly VOC use and monthly VOC emissions. The records shall include calculation of total emissions for each rolling 12-month period. The records shall be made available to the Division for inspection upon request.

II.C.1.a.(v) (State Only) Existing sources that are modified – undergo any physical change, or changed in the method of operation of a stationary source which increase VOC or NOx emissions – on or after March 30, 2008, shall utilize RACT control technologies pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. upon recommencing operation.

II.C.1.b. Provided however, that no existing source of VOC emissions employing emission controls on or within the six-month period preceding the effective date of this regulation may reduce its level of control of VOC emissions below that level of control actually achieved, even though such source may otherwise be subject to less stringent control requirements, except that no existing source shall be required to control emissions to an extent greater than that level of control which RACT would achieve.

II.C.1.c. (State Only) Existing sources with potential emissions equal to or greater than 100 tons per year of volatile organic compound emissions shall submit a permit modification application that includes a revised APEN (or APENs) and a RACT analysis, to the Division, as follows:

II.C.1.c.(i) (State Only) By October 30, 1991 if located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area; or

II.C.1.c.(ii) (State Only) By April 30, 2009 or within one year after the date on which the area is first designated as being in nonattainment for ozone, whichever comes later, if they are located in the 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area.

II.C.1.d. (State Only) Existing sources shall utilize RACT pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. by whichever date comes later:

II.C.1.d.(i) (State Only) October 30, 1991, if they are located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area;

II.C.1.d.(ii) (State Only) November 21, 2011, if they are located in the 8-hour Ozone Control Area, and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area;

II.C.1.d.(iii) (State Only) Three years after the date on which the area is first designated as being in nonattainment for ozone; or

II.C.1.d.(iv) (State Only) Two years after Division determination of case-by-case RACT pursuant to this Section II.C.1. The Division shall be deemed to have approved the RACT analysis for purposes of this Section II.C.1.d.(iv) if it does not object after eighteen months from having received a complete permit application.

II.C.2. New Sources

All new sources shall utilize controls representing RACT, pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D., upon commencement of operation.

II.D. Alternative Control Plans and Test Methods

II.D.1. Sources subject to specific requirements of this regulation shall submit for approval as a revision to the State Implementation Plan:

II.D.1.a. Any alternative emission control plan or compliance method other than control options specifically allowed in the applicable regulation. Such alternative control plans shall provide control equal to or greater than the emission control or reduction required by the regulation, unless the source contends that the control level required by the regulation does not represent RACT for their specific source.

II.D.1.b. Any alternative test method or procedure not specifically allowed in the applicable regulation.

II.D.2. No alternative submitted pursuant to this Section II.D. is effective until the alternative is approved as a revision to the State Implementation Plan.

II.E. REPEALED

II.F. Provisions for Specific Processes

II.F.1. The Gates Rubber Company Provision – REPEALED

Appendix A Colorado Ozone Nonattainment or Attainment Maintenance Areas

I. Chronology of Attainment Status

Denver Metropolitan Area Only

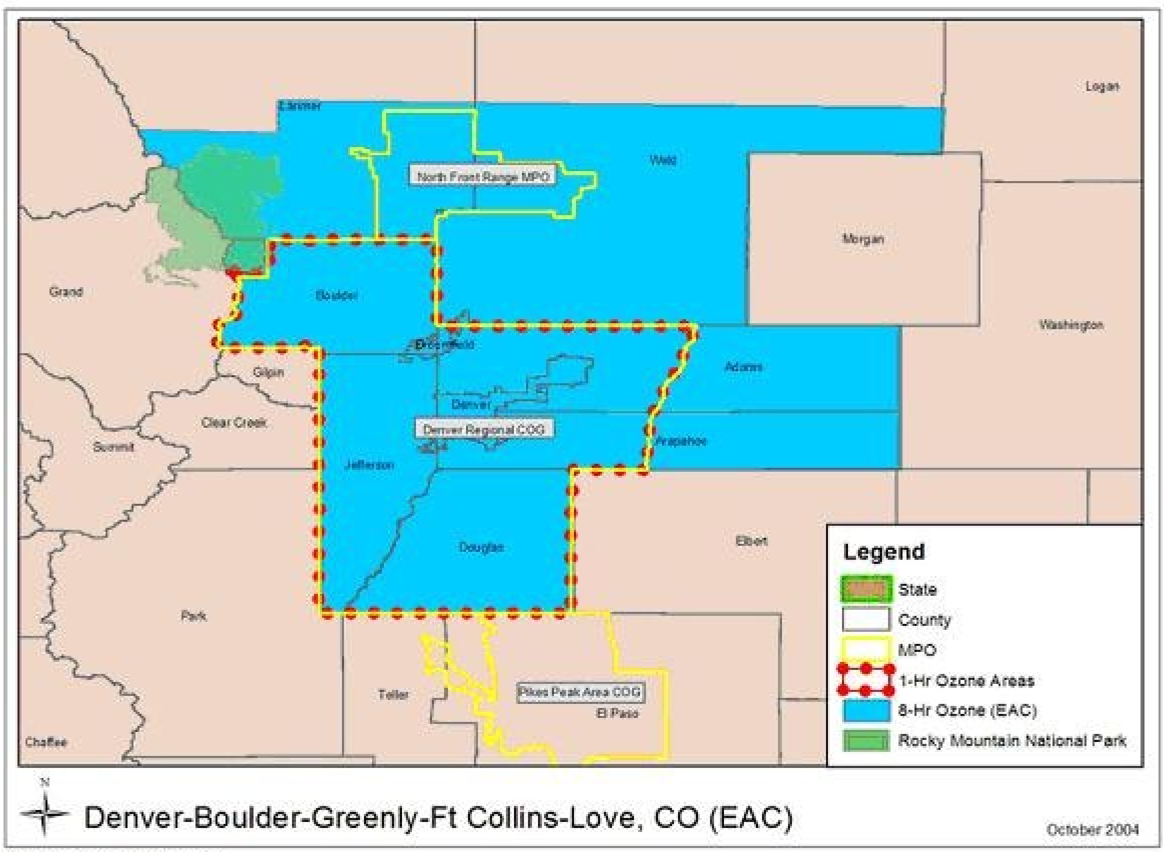
1978	Denver 1-hour Ozone Nonattainment Area designation first becomes effective in 7-county Denver Metropolitan Area
10/11/01	Denver 1-hour Ozone Attainment Maintenance Area designation replaces non-attainment designation and becomes effective in 7-county Denver Metropolitan Area
9/2/05	1-hour Ozone National Ambient Air Quality Standard is Revoked in Colorado except for the Denver 1-hour Ozone Attainment Maintenance Area.

Denver Metropolitan Area and North Front Range

10/11/01	1-hour attainment maintenance area replaces non-attainment designation for the Denver Metro Area/North Front Range Area
4/15/04	EPA designates the Denver Metro Area/North Front Range region as an 8-hour ozone non-attainment area, designation deferred due to the implementation of the Early Action Compact
11/20/07	Denver 8-hour ozone non-attainment designation becomes effective in 9 county Denver Metropolitan Area

II. Maps

Denver Metropolitan Area and North Front Range



Prepared by FHWA - HEPN-40

PART B Storage, Transfer, and Disposal of Volatile Organic Compounds and Petroleum Liquids and Petroleum Processing and Refining

I. General Requirements for Storage and Transfer of Volatile Organic Compounds

I.A. Maintenance and Operation of Storage Tanks and Related Equipment

All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing and monitoring shall be conducted as in Part B, Section VI.C.3.

I.B. Transfer (excluding Petroleum Liquids)

Except as otherwise provided in this regulation, all volatile organic compounds transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

I.C. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of Section I.B.

II. Storage of Highly Volatile Organic Compounds

II.A. Highly volatile organic compounds shall be stored:

II.A.1. In a pressure tank which is at all times capable of maintaining working pressures sufficient to prevent vapor loss to the ambient air; or

II.A.2. With methods and/or equipment approved by the Division in writing pursuant to the request of the person owning or operating the storage facility.

II.B. Vapor loss shall be determined visually, by presence of frost or condensation at the point of leakage, or using a portable hydrocarbon analyzer. When an analyzer is used, vapor loss means a VOC concentration exceeding 10,000 ppm and testing and monitoring procedures shall be conducted as in Part B, Section VI.C.3.

III. Disposal of Volatile Organic Compounds

III.A. No person shall dispose of volatile organic compounds by evaporation or spillage unless RACT is utilized.

III.B. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

IV. Storage and Transfer of Petroleum Liquid

IV.A. General Requirements

IV.A.1. No person shall build, install, or permit the building or installation of any rotating pump or compressor handling any type of petroleum liquid unless said pump or compressor is equipped with mechanical seals or other equipment of equal efficiency. If reciprocating-type pumps and compressors are used, they shall be equipped with packing glands properly installed, in good working order, and properly maintained so that no detectable emissions occur from the drain recovery systems.

IV.A.2. Definitions

For the purpose of this section, the following definitions apply:

IV.A.2.a. Repealed.

IV.A.2.b. "Crude Oil" means a naturally occurring mixture which consists of hydrocarbons, sulfur, nitrogen or oxygen derivatives of hydrocarbons, and which is a liquid at standard conditions.

IV.A.2.c. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

IV.A.2.d. "EFR Tank" means a storage vessel having an external floating roof.

IV.A.2.e. "External Floating Roof" means a storage vessel cover in an open top tank consisting of a double deck or pontoon single deck which rests upon and is supported by the petroleum liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

IV.A.2.f. “Liquid-Mounted Seal" means a primary seal mounted in continuous contact with the contained liquid and which occupies an annular space between the inner tank wall and the perimeter of the floating roof.

IV.A.2.g. "Petroleum Liquid" means crude oil, condensate and any finished or intermediate product manufactured or extracted in a petroleum refinery.

IV.A.2.h. "Shoe Seal" means a primary seal employing a metallic band (called a shoe) which is held against the vertical inner-wall of the tank, concentric with the perimeter of the floating roof.

IV.A.2.i. "Vapor Balance System" means a combination of pipes or hoses that create a closed system between the vapor spaces of an unloading tank and a receiving tank such that vapors displaced from the receiving tank are transferred to the tank being unloaded.

IV.A.2.j. “Vapor Collection System” means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

IV.A.2.k. "Vapor-Mounted Seal" means a primary seal mounted so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the liquid surface, the floating roof, and the tank wall (thus excluding shoe seals).

IV.A.2.l. "Waxy, Heavy Pour Crude Oil" means a crude oil with a pour point of 10°C (50°F) or higher as determined by the American Society for Testing and Materials Standard D97-66, "Test for Pour Point of Petroleum Oils."

IV.B. Storage of Petroleum Liquid

IV.B.1. Exemptions

IV.B.1.a. Tanks or other containers used to store the following liquids are exempt from the provisions of Sections IV.B.2. and IV.B.3.:

IV.B.1.a.(i) Diesel Fuels 1-D, 2-D, and 4-D as defined in ASTM D975-78.

IV.B.1.a.(ii) Fuel Oils #1, #2, #3, #4, and #5, as defined in ASTM D396-78.

IV.B.1.a.(iii) Gas Turbine Fuels 1-GT through 4-GT as defined in ASTM D2880-78.

IV.B.1.b. The following underground storage facilities are exempt from Section IV.B.2.:

IV.B.1.b.(i) Underground tanks if the annual sum total of the volume of liquid removed from the tank plus the sum of the volume of liquid added to it does not exceed twice the operational volume of the tank (i.e., a maximum of one turnover per year is allowed).

IV.B.1.b.(ii) Subsurface caverns or porous rock reservoirs.

IV.B.1.b.(iii) Horizontal underground tanks storing JP-4 Jet Fuel.

IV.B.2. Storage of petroleum liquid in tanks greater than 151,412 liters (40,000 gallons)

IV.B.2.a. Storage of petroleum liquid in fixed-roof tanks.

IV.B.2.a.(i) The owner or operator of a fixed-roof tank used for storage of petroleum liquids which have a true vapor pressure greater than 33.6 torr (0.65 psia) at 20°C (or, alternatively, a Reid vapor pressure greater than 1.30 pounds - (67.2 torr) but not greater than 570 torr (11.0 psia) at 20°C, and which are stored in any tank or other container of more than 151,412 liters (40,000 gallons) shall ensure that the tank at all times meets the following conditions:

IV.B.2.a.(i)(A) The tank has been equipped with a pontoon-type, or double-deck type, floating roof or an internal floating cover which rests on the surface of the liquid contents and which is equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and tank walls; or

IV.B.2.a.(i)(B) The tank has been equipped with a vapor gathering system capable of collecting the petroleum liquid vapors discharged, together with a vapor recovery or disposal system capable of processing such vapors so as to prevent their emission into the atmosphere.

IV.B.2.a.(i)(C) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections III.A.3.a., b., c., and e., and III.A.8.a. and b.

IV.B.2.a.(i)(D) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.B.2.a.(i)(E) The owner or operator shall maintain records for at least two years of the type, average monthly storage temperature, and true vapor pressure of all petroleum liquids stored in tanks not equipped with an internal floating roof or cover or other control pursuant to Regulation Number 7, Sections IV.B.2.a.(i)(A) or IV.B.2.a.(i)(B) or Part A, Section II.D.

IV.B.2.a.(ii) No owner or operator of a fixed-roof tank equipped with an internal floating roof or cover shall permit the use of such tank unless:

IV.B.2.a.(ii)(A) The tank is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; and

IV.B.2.a.(ii)(B) All openings, except stub drains, are equipped with covers, lids, or seals such that:

IV.B.2.a.(ii)(B)(1) The cover, lid, or seal is in the closed position at all times except when in actual use;

IV.B.2.a.(ii)(B)(2) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports; and

IV.B.2.a.(ii)(B)(3) Rim vents, if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

IV.B.2.a.(iii) The operator of a fixed-roof tank equipped with an internal floating roof shall:

IV.B.2.a.(iii)(A) Perform a routine inspection through the tank roof hatches at least once every six months;

IV.B.2.a.(iii)(A)(1) During the routine inspection, the operator shall measure for detectable vapor loss inside the hatch. Detectable vapor loss means a VOC concentration exceeding 10,000 ppm, using a portable hydrocarbon analyzer.

IV.B.2.a.(iii)(B) Perform a complete inspection of the cover and seal whenever the tank is out of service, whenever the routine inspection required in Section IV.B.2.a.(iii)(A) reveals detectable vapor loss, and at least once every ten years, and shall notify the Division in writing before such an inspection.

IV.B.2.a.(iii)(C) Ensure during inspections that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; that the cover is floating uniformly on or above the liquid surface; that there are no visible defects in the surface of the cover or liquid accumulated on the cover; and that the seal is uniformly in place around the circumference of the cover between the cover and the tank wall. If these items are not met, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this section cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Division in writing. Such a request must document that alternative storage capacity is unavailable and specify a schedule of actions the owner or operator will take that will assure that the items will be repaired or the vessel will be emptied as soon as possible;

IV.B.2.a.(iii)(D) Maintain records for at least two years of the results of all inspections.

IV.B.2.b. Above ground storage tanks used for the storage of petroleum liquid shall have all external surfaces coated with a material which has a reflectivity for solar radiation of 0.7 or more. Methods A or B of ASTM E424 shall be used to determine reflectivity. Alternatively, any untinted white paint may be used which is specified by the manufacturer for such use.

This provision shall not apply to written symbols or logograms applied to the external surface of the container for purposes of identification provided such symbols do not cover more than 20% of the exposed top and side surface area of the container or more than 18.6 square meters (200 square feet), whichever is less.

IV.B.2.c. Seals on External Floating Roof Tanks

IV.B.2.c.(i) General Provisions

IV.B.2.c.(i)(A) Applicability

This section applies to all petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 150,000 liters (40,000 gallons) that are located in ozone nonattainment areas.

IV.B.2.c.(i)(B) Exemptions

IV.B.2.c.(i)(B)(1) Total Exemption

The following categories of EFR tanks are exempt from the requirement of Section IV.B.2.c., except for the applicable recordkeeping requirements of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(1)(a) EFR tanks which store any material whose true vapor pressure as stored never exceeds 67 torr (1.3 psia).

IV.B.2.c.(i)(B)(1)(b) Tanks less than 1,600,000 liters (10,000 barrels) which are used to store crude oil and condensate prior to custody transfer.

IV.B.2.c.(i)(B)(2) Limited Exemptions

The following are exempt from both secondary seal and secondary seal inspection requirements but shall meet the equipment/procedure provisions in Section IV.B.2.c.(ii)(A)(1), the semi-annual inspection provisions of Section IV.B.2.c.(ii)(B), and the record keeping provisions of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(2)(a) Those tanks storing petroleum liquid between 67 and 207 torr (1.3 to 4.0 psia) maximum true vapor pressure (as stored) which are of welded construction and which have one of the following primary seals:

IV.B.2.c.(i)(B)(2)(a)(I) metallic shoe seal

IV.B.2.c.(i)(B)(2)(a)(II) liquid mounted, resilient seal

IV.B.2.c.(i)(B)(2)(a)(III) liquid mounted, liquid filled seal

IV.B.2.c.(i)(B)(2)(b) Any tank storing waxy, heavy-pour crude oil.

IV.B.2.c.(ii) General Requirements

IV.B.2.c.(ii)(A) An operator of an EFR tank storing petroleum liquids with true vapor pressure (as stored) above 67 torr (1.3 psia) shall equip the tank as follows and observe the following procedures:

IV.B.2.c.(ii)(A)(1) Equipment

IV.B.2.c.(ii)(A)(1)(a) Drains: roof drains which are designed to empty directly into the stored product shall be provided with slotted-membrane fabric covers or equivalent covers which cover at least 90 percent of the area of the opening.

IV.B.2.c.(ii)(A)(1)(b) Openings: except for automatic bleeder vents, rim space vents, and leg sleeves, all openings shall be equipped with:

IV.B.2.c.(ii)(A)(1)(b)(I) Projections into the tank which remain below the liquid surface at all times; and

IV.B.2.c.(ii)(A)(1)(b)(II) Covers, seals, or lids.

IV.B.2.c.(ii)(A)(2) Procedures

IV.B.2.c.(ii)(A)(2)(a) Covers, seals and lids shall be kept closed except when the openings are in actual use.

IV.B.2.c.(ii)(A)(2)(b) Automatic bleeder vents shall be kept closed at all times except when the roof is floated off or landed on roof leg supports.

IV.B.2.c.(ii)(A)(2)(c) Rim vents shall be set to open at the manufacturer's recommended setting or, alternatively, only when the roof is being floated off the leg supports.

IV.B.2.c.(ii)(B) Inspections

The operator of an EFR tank subject to this Section IV.B.2.c. shall:

IV.B.2.c.(ii)(B)(1) Perform routine inspections at least once every six months in order to ensure compliance with Section IV.B.2.c.(ii)(B)(2). The inspections shall include a visual inspection of the secondary seal gap if equipped with a secondary seal.

IV.B.2.c.(ii)(B)(2) Ensure that all seal closure devices meet the following requirements:

IV.B.2.c.(ii)(B)(2)(a) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; and

IV.B.2.c.(ii)(B)(2)(b) The seal(s) are intact and uniformly in place around the circumference of the floating roof and the tank wall.

IV.B.2.c.(ii)(C) Records

IV.B.2.c.(ii)(C)(1) Operators shall:

IV.B.2.c.(ii)(C)(1)(a) Maintain records of the average monthly storage temperature, the Reid vapor pressure of the liquid and the type of liquid stored for all EFR tanks lacking secondary seals and receiving petroleum liquids with a true vapor pressure of 1.0 psi (7.0kPa) or greater; and

IV.B.2.c.(ii)(C)(1)(b) Maintain records of the results of the inspections required herein.

IV.B.2.c.(ii)(C)(2) Copies of all records specified by this Section IV.B.2.c.(ii)(C) shall be retained by the operator for a minimum of two years after the date on which the record was made.

IV.B.2.c.(iii) Secondary Seal Requirements

IV.B.2.c.(iii)(A) General

No owner or operator of an EFR tank (storing petroleum liquids) not specifically exempted in Section IV.B.2.c.(i)(B) shall store that petroleum liquid unless such vessel is equipped with a continuous secondary seal extending from the rim of the floating roof to the tank wall (i.e., a rim-mounted secondary seal).

IV.B.2.c.(iii)(B) Vapor-Mounted Seals

For EFR tanks required to have a secondary seal and which have a vapor-mounted primary seal:

IV.B.2.c.(iii)(B)(1) An annual inspection shall be made of the total gap area between the secondary seal and the wall of the tank in accordance with the method in IV.B.2.c.(iii)(B)(3).

IV.B.2.c.(iii)(B)(2) This total gap area shall not exceed 21.2 cm2/meter diameter (1.0 in2/ft. diameter).

IV.B.2.c.(iii)(B)(3) Method to determine gap area:

IV.B.2.c.(iii)(B)(3)(a) Physically measure the length and width of all gaps around the entire circumference of the secondary seal in each place where a 0.32 cm (1/8 in.) uniform diameter probe passes freely (without forcing or binding against the seal) between the seal and the tank wall; and,

IV.B.2.c.(iii)(B)(3)(b) Sum the area of the individual gaps.

IV.B.3. Storage of petroleum liquid in tanks of or less than 151,412 liters (40,000 gallons) capacity.

IV.B.3.a. Tanks or containers used to store liquids with true vapor pressure at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) at 20°C are exempt from the provisions of this Section IV.B.3.

IV.B.3.b. The owner or operator of storage tanks at a gasoline dispensing facility (service station) or other facility not addressed in Sections IV.C.2. or IV.C.3., which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and all vapors displaced from the storage tank are transferred to the delivery vessel being unloaded using a properly maintained, functioning, and leak-tight vapor collection system, as in accordance with applicable provisions of Appendix B and Section VII., if the tank:

IV.B.3.b.(i) Has a rated manufacturer's capacity of 2,082 liters (550 gallons) or more and was installed after November 7, 1973, (except for storage tanks below 550-gallon capacity used exclusively for agricultural use; however, these must have a submerged fill pipe), or

IV.B.3.b.(ii) Has a rated manufacturer's capacity of 7,571 liters (2,000 gallons) or more and was installed before November 7, 1973.

IV.B.3.c. Tanks equipped with a submerged fill pipe shall meet the specifications of Appendix B.

IV.B.3.d. The owner or operator of storage tanks at a gasoline dispensing facility must install and operate one or more of the following

IV.B.3.d.(i) A vapor collection system designed and operated in accordance with a vapor-tight line from the storage tank to delivery vessel.

IV.B.3.d.(ii) A refrigerator-condensation system or equivalent designed to recover at least 90 percent by weight of the organic compounds in the displaced vapor.

IV.B.3.e. The owner or operator shall ensure that operating procedures are used so that gasoline cannot be transferred into the tank unless the vapor collection system is installed and operated to ensure the system is leak-tight during gasoline transfer.

IV.B.3.f. The vapor collection system shall meet the specifications of Appendix B and applicable requirements of Section VII.

IV.B.3.g. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

IV.B.3.h. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C. Transfer of Petroleum Liquid

IV.C.1. Exemptions

Transfer operations involving petroleum liquid with true vapor pressures at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) shall be exempt from the provisions of this Section IV.C.

IV.C.2. Loading Facilities Classified as Terminals

IV.C.2.a. A terminal is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of more than 76,000 liters of gasoline (20,000 gallons), which is loaded directly into transport vehicles. A rolling, 30-day average of throughput shall be used to determine the applicability of this Section IV.C.2.

IV.C.2.b. The owner or operator of a terminal subject to this section shall equip the terminal with proper loading equipment and shall follow the loading procedures listed:

IV.C.2.b.(i) Install dry-break loading couplings to prevent petroleum liquid loss during uncoupling from vehicles.

IV.C.2.b.(ii) Install a vapor collection and disposal system which gathers vapor transferred from vehicles being loaded. The system shall include devices to prevent the release of vapor from vapor recovery hoses not in use.

IV.C.2.b.(iii) Use operating procedures to ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

IV.C.2.b.(iv) Provide for the prevention of overfilling of transport vehicles with loading pump shut-offs, set stop meters, or comparable equipment.

IV.C.2.b.(v) Operate all recovery and disposal equipment at a back pressure less than the pressure relief valve setting of transport vehicles.

IV.C.2.b.(vi) Prevent the release of petroleum liquid on the ground from transport vehicles. Provision shall be made to remove any undelivered petroleum liquid with closed drainage devices.

IV.C.2.b.(vii) Maintain and operate final recovery and disposal equipment or control devices so as to emit no more than 80 milligrams of volatile organic compounds per liter of gasoline being loaded. Such disposal devices shall be approved by the Division.

IV.C.2.b.(viii) Prevent loading of petroleum liquid into transport vehicles which do not have valid leak-tight test certification as required in Section IV.D.

IV.C.2.b.(ix) Follow all control procedures to prevent leaks as specified in Section VII.

IV.C.2.c. Control devices shall meet the applicable requirements, including recordkeeping of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

IV.C.2.d. The applicable methods of 40 CFR 60. 503 (September 14, 1989), or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C.2.e. The method set forth in Appendix A of "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals" October 1977, EPA-450/2-77-026 shall be used to test emission points other than control devices.

IV.C.3. Loading Facilities Classified as Bulk Plants

IV.C.3.a. A bulk plant is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of 76,000 liters of gasoline (20,000 gallons) or less, which is loaded directly into transport trucks. (As used herein, "bulk plant" does not include service stations nor separate operations within petroleum liquid distribution facilities which pump only into fuel tanks fueling motor vehicles. Both such operations are regulated by Section IV.B.3.). A rolling 30-day average of throughput shall be used to determine the applicability of this regulation.

IV.C.3.b. The owner or operator of a bulk storage plant subject to this section shall install a vapor balance system to return vapors to the incoming transport trucks during the filling of tanks controlled under Section IV.B.3. The vapor balance system must be designed and operated in accord with the provisions of Appendix C.)

IV.C.3.c. The owner or operator of a bulk plant which serves storage tanks which are required to collect and recover vapor as prescribed in Section IV.B.3. shall:

IV.C.3.c.(i) Install and operate vapor collection and return equipment on any transport vehicles used to deliver to controlled tanks, and

IV.C.3.c.(ii) Install and operate vapor collection and return equipment at loading facilities to collect vapors during loading of tank compartments of outbound transport trucks and return these vapors to the bulk plant storage tanks, using a vapor balance system.

IV.C.3.c.(iii) Assure that transport trucks and loading facilities conform to the applicable provisions of Sections IV.C.2. and IV.C.4.

IV.C.3.d. The owner or operator of a bulk plant which serves only storage tanks exempted from the provisions of Section IV.B.3.b. by reason of their small size or location in an attainment area shall load outbound transport trucks using equipment that provides for top loading of the petroleum liquid into the vehicle tank compartments through an extended fill tube which reaches within 15.24 cm (6 in.) of the bottom of the tank compartment.

IV.C.3.e. The owner or operator of a bulk plant subject to this section shall ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

IV.C.3.f. The owner or operator of a bulk plant subject to this section shall follow all procedures to prevent leaks as specified in Section VII.

IV.C.4. Transport Vehicles

IV.C.4.a. Rail cars shall be loaded only at facilities which allow for the following:

IV.C.4.a.(i) A submerged fill pipe which reaches within 15.24 cm (6 in.) of the bottom of the tank.

IV.C.4.a.(ii) Vapor collection and/or disposal equipment designated and operated to recover vapors displaced during the loading of the rail car.

IV.C.4.a.(iii) A vapor-tight seal around the tank car hatch and the loading equipment.

IV.C.4.b. The owner or operator of petroleum transport trucks which serve locations required to be equipped with vapor recovery equipment shall load only at facilities capable of disposing of collected vapors. The owner or operator shall assure that such vehicles possess the proper equipment and that work practices are followed so that:

IV.C.4.b.(i) Dry-break loading and unloading nozzles are used and are compatible with those required at loading facilities.

IV.C.4.b.(ii) Vapor recovery hoses are connected at all times during unloading or loading of petroleum distillate.

IV.C.4.b.(iii) Transport trailers and vehicle tanks are operated and maintained to prevent detectable hydrocarbon vapor loss during loading, transport and delivery.

IV.C.4.b.(iv) Compartment dome lids are closed and locked during transfers of petroleum liquid. Such lids may be opened for the purpose of certifying the accuracy of a delivery only prior to and after such delivery.

IV.C.4.b.(v) Hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loading or unloading.

IV.D. Control of Volatile Organic Compound Leaks from Gasoline Transport Trucks

IV.D.1. General Provisions

IV.D.1.a. Applicability

This section is applicable to all gasoline transport trucks equipped for gasoline vapor collection which receive or dispense gasoline at terminals, bulk plants, or gasoline dispensing facilities located in the nonattainment areas.

IV.D.1.b. Definitions

For the purpose of this section, the following definitions apply:

IV.D.1.b.(i) "Gasoline Transport Truck" means a tank truck or tank trailer equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants, or gasoline terminals.

IV.D.1.b.(ii) "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into a vessel being unloaded or into a vapor holding tank.

IV.D.2. Provisions for Specific Processes

IV.D.2.a. No terminal operator, when monitoring the gasoline loading operation and no owner or operator of a gasoline transport truck shall allow a gasoline transport truck subject to this Section IV.D. to be filled with a VOC with Reid Vapor Pressure of 4.0 or greater unless the gasoline tank truck:

IV.D.2.a.(i) Is tested annually according to the test procedure in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). Testing must be completed prior to the onset of the summer ozone season (test October through April). In addition, a visual inspection, as detailed in Section IV.D.3.b. must be performed at least once every six months.

IV.D.2.a.(i)(A) The test must be conducted using a time period (t) for the pressure and vacuum tests of 5 minutes.

IV.D.2.a.(i)(B) The initial pressure (P_i) for the pressure test must be 460 mm H_2O (18 in. H_2O), gauge.

IV.D.2.a.(i)(C) The initial vacuum (V_i) for the vacuum test must be 150 mm H_2O (6 in. H_2O), gauge.

IV.D.2.a.(i)(D) The maximum allowable pressure and vacuum changes must not exceed the values in Table 1.

IV.D.2.a.(i)(E) After completing the tests under Sections IV.D.2.a.(i)(A) through (D), the tank's internal vapor valve must be pressure tested.

IV.D.2.a.(i)(E)(1) Use the procedures in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000) to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge.

IV.D.2.a.(i)(E)(2) Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

IV.D.2.a.(i)(E)(3) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line.

IV.D.2.a.(i)(E)(4) After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

Table 1 - Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change in 5 minutes, mm H2O (in. H2O)	Allowable pressure change in 5 minutes at any time, mm H2O (in. H2O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

IV.D.2.a.(ii) Passes a retest within twenty (20) days if it does not meet the criteria of Section IV.D.2.a.(i).

IV.D.2.b. Monitoring

IV.D.2.b.(i) The Division may, at any time, monitor a gasoline tank truck vapor collection system to confirm continued compliance with Section IV.D.2.a.

IV.D.2.b.(ii) Within fifteen (15) days after an exceedance is detected a tank shall pass a pressure/vacuum test per EPA Method 27 (40 CFR Part 60, Appendix A-8 (October 17, 2000)).

IV.D.3. Testing and Monitoring

IV.D.3.a. The owner or operator of a gasoline transport truck shall at their own expense, demonstrate compliance with Section IV.D.2, by methods of EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). All tests shall be made by, or under the direction of, a person qualified by training and/or experience in the field of air pollution testing or gasoline transport truck maintenance.

IV.D.3.b. The owner or operator of a gasoline transport truck must conduct a visual inspection of the gasoline transport truck at least once every six months. The entire tank, including domes, dome vents, cargo tank, piping, hose connections, hoses and delivery elbows, must be inspected for wear, damage, or misadjustment that could be a potential leak source. Inspect all rubber fittings except those in piping which are not accessible. Any part found to be defective must be adjusted, repaired, or replaced as necessary.

IV.D.4. Recordkeeping and Reporting

IV.D.4.a. The owner or operator of a gasoline transport truck subject to this Section IV.D. shall maintain records of all certification testing and repairs. The records shall identify the gasoline transport truck, the date of the test or repairs and, if applicable, the type of repair and the date of retest. The written record shall include entries of any pre-test repairs, adjustments, or modifications. These shall also include the part name, number, and vendor name of any part removed and of any part installed. The records shall be maintained in legible, readily available form for at least two (2) years after the date the testing or repair was completed and shall be made available to the Division for inspection upon request.

IV.D.4.b. The records of certification tests required by Section IV.D.2.a. must, as a minimum, contain all of the following entries:

IV.D.4.b.(i) The gasoline transport truck owner’s name and address;

IV.D.4.b.(ii) The gasoline transport truck/tank identification number;

IV.D.4.b.(iii) The nature of repair work and when performed in relation to vapor tightness testing.

IV.D.4.b.(iv) The following data for each test:

IV.D.4.b.(iv)(A) Test pressure.

IV.D.4.b.(iv)(B) Pressure or vacuum change, mm of water.

IV.D.4.b.(iv)(C) Time period of test.

IV.D.4.b.(iv)(D) Number of leaks found with instrument.

IV.D.4.b.(iv)(E) Leak definition.

IV.D.4.b.(v) The size of each of the compartments within the tank and whether such compartment was manifolded or was tested separately during pressure and vacuum tests.

IV.D.4.b.(vi) At the top of each report page shall be the company name and the date and location of the test results recorded on that page; and

IV.D.4.b.(vii) Name and title of the person conducting the test.

IV.D.4.b.(viii) For the vapor valve test required in Section IV.D.2.a.(ii)(A), the initial test pressure and time of reading.

IV.D.4.c. The records of the visual inspections required by Section IV.D.3.b.

IV.D.4.d. The owner or operator of a gasoline transport truck subject to this regulation must annually certify to the Division that the gasoline transport truck has been tested by the applicable method(s) referenced in Section IV.D.3. The certification must include:

IV.D.4.d.(i) The name and address of the company and the name and telephone number of responsible company representative over whose signature the certification is submitted; and,

IV.D.4.d.(ii) A copy of the information recorded to comply with Section IV.D.4.b.

IV.D.4.e. The records of certification tests must be kept with the tank or at the transport company office at all times and must be shown to Division personnel upon their request. Copies of all records and reports required by the provisions of this Section IV.D. must be made available to the Division upon oral or written request.

V. Crude Oil

V.A. General Exemptions

V.A.1. Storage tanks of 151,412 liters (40,000 gallons) or less used to store crude oil is exempt from the provisions of this section.

V.A.2. Storage tanks with capacities of less than 1,590 cubic meters (10,000 barrels) used to store crude oil and condensate prior to lease custody transfer are exempt from the provisions of this Regulation Number 7 other than Part D, Sections I. and II.

V.B. Equipment

Pumps and compressors handling crude oil shall be subject to the provisions of Section IV.A.

V.C. Storage

Except as provided in Section V.A.2., crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Sections IV.B.1.b. and IV.B.2.

VI. Petroleum Processing and Refining

VI.A. Wastewater (Oil/Water) Separators

VI.A.1. Definitions

VI.A.1.a. "Forebays" mean the primary sections of a wastewater separator.

VI.A.1.b. "Wastewater (oil/water) separator" means any device or piece of equipment which utilizes the difference in density between oil and water to remove oil and associated chemicals from water, or any device, such as a flocculation tank, clarifier, etc., which removes petroleum derived compounds from wastewater.

VI.A.2. The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall:

VI.A.2.a. Equip the forebays and separator sections of the wastewater separators with one or more of the following emission control devices, ensuring that such device is properly installed, in good working order and properly maintained:

VI.A.2.a.(i) A solid cover with all openings sealed and the liquid contents totally enclosed.

VI.A.2.a.(ii) A pontoon-type or double-deck type floating roof, or internal floating cover. The floating roof or cover must rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and the wall(s) of the compartment.

VI.A.2.a.(iii) A vapor recovery system consisting of a vapor gathering device capable of collecting the volatile organic compound vapors discharged and a vapor disposal device capable of processing such volatile organic vapors so as to prevent their emission into the atmosphere.

VI.A.2.a.(iii)(A) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.A.2.a.(iii)(B) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

VI.A.2.b. Equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized.

VI.B. Emissions from Petroleum Refineries

VI.B.1. Definitions

VI.B.1.a. "Firebox" means the chamber or compartment of a boiler or furnace in which materials are burned but does not mean the combustion chamber of an incinerator.

VI.B.1.b. "Turnaround" means the procedure of shutting a refinery unit down after a run to do necessary maintenance and repair work and then putting the unit back on stream.

VI.B.2. Process unit turnarounds

The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for:

VI.B.2.a. Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency;

VI.B.2.b. No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and

VI.B.2.c. Recordkeeping of the following items. Records shall be kept for at least two years and shall be made available to the Division for review upon request.

VI.B.2.c.(i) Every date that each process unit is shut down,

VI.B.2.c.(ii) The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere, and

VI.B.2.c.(iii) The approximate total quantity of volatile organic compounds emitted to the atmosphere.

VI.B.3. Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

VI.B.4. Vacuum-Producing Systems

VI.B.4.a. The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensible volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by:

VI.B.4.a.(i) Venting the noncondensible vapors to a flare or other combustion device, or,

VI.B.4.a.(ii) Compressing the vapors and adding them to the refinery fuel gas.

VI.B.5. All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access.

VI.B.6. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.B.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

VI.C. Petroleum Refinery Equipment Leaks

VI.C.1. Definitions

For the purpose of this section, the following definitions apply:

VI.C.1.a. "Accessible Component" means a component which can be reached, if necessary, by safe and proper use of portable ladders such as are acceptable to OSHA, as well as by built-in ladders and walkways. "Accessible" also includes components which can be reached by the safe use of an extension on the monitoring probe.

VI.C.1.b. "Component" means any piece of equipment, which has the potential to leak volatile organic compounds when tested in the manner described in Section VI.C.3. These sources include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open ended pipes. Excluded from these sources are valves which are not externally regulated.

VI.C.1.c. "Gaseous Service" means equipment which processes, transfers or contains a volatile organic compound or mixture of volatile organic compounds in the gaseous phase.

VI.C.1.d. "In Heavy VOC Liquid Service" means that the piece of equipment is not in gaseous service or in light VOC liquid service.

VI.C.1.e. "In Light Liquid VOC Service" Equipment is in light liquid service if the following conditions apply:

VI.C.1.e.(i) the true vapor pressure of one or more of the components is greater than 0.3 kPa at 20°C. True vapor pressures may be obtained from standard reference texts or may be determined by ASTM D-2879.

VI.C.1.e.(ii) the total concentration of the pure components have a true vapor pressure greater than 0.3 kPa at 20°C, is equal to or greater than 20 percent by weight; and

VI.C.1.e.(iii) the fluid is a liquid at operating conditions.

VI.C.1.f. "Refinery Unit" means a set of components which are a part of a basic process operation, such as, distillation, hydrotreating, cracking, or reforming of hydrocarbons.

VI.C.1.g. "Water Draw" means a routinely used valve or system employing a valve which allows non-VOC material (usually water) to be separated from VOC.

VI.C.2. Provisions for Specific Processes

VI.C.2.a. The owner or operator of a petroleum refinery complex subject to this regulation shall:

VI.C.2.a.(i) Develop a monitoring program consistent with the provisions in Section VI.C.3.

VI.C.2.a.(ii) Conduct a monitoring program consistent with the provisions in Section VI.C.4.a.

VI.C.2.a.(iii) Record all leaking components which have a VOC concentration exceeding 10,000 ppm when tested according to Section VI.C.3., and place an identifying tag on each component consistent with the provisions in Section VI.C.4.a.(iii).

VI.C.2.a.(iv) Repair and retest leaking components, as defined in Section VI.C.2.a.(iii), as soon as possible, but no later than fifteen (15) days after the leak is found, excepting those specified in Sections VI.C.2.a.(v) and VI.C.2.a.(vi).

VI.C.2.a.(v) Identify all leaking components as defined in Section VI.C.2.a.(iii), which cannot be repaired until the unit is shut down for turnaround, and repair and retest as in Section VI.C.2.a.(iv) when the unit is back on stream.

VI.C.2.a.(vi) When a component leak cannot be fixed within fifteen (15) working days solely because parts are not available, the following shall be noted in an "awaiting parts log:"

VI.C.2.a.(vi)(A) component identification and tag number

VI.C.2.a.(vi)(B) date part was ordered

VI.C.2.a.(vi)(C) date part was received

VI.C.2.a.(vi)(D) date repair was made

VI.C.2.b. Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use.

VI.C.2.c. The Division, at its discretion, may require early unit turnaround based on the number and severity of tagged leaks awaiting turnaround provided:

VI.C.2.c.(i) The requirement does not exceed reasonable available control technology due to cost per ton of emissions reduction achieved by the early turnaround or other reasonable analysis.

VI.C.2.c.(ii) The Division provides the owner or operator of a petroleum refinery with written notification at least 180 days before requiring an early turnaround. The owner or operator will have 30 days from the date of the Division's notification to contest the requirement by submitting a demonstration that the requirement is beyond reasonable available control technology. If no demonstration is made, it will be assumed the requirement is reasonable. If a demonstration is submitted by the owner or operator, the Division will either approve the demonstration or disapprove the demonstration with a justification regarding the disapproval within 30 days of the date the demonstration is submitted to the Division.

VI.C.2.c.(iii) The requirement is not contested by the owner or operator. Should the requirement be contested, the requirement for early unit turnaround will be delayed until 180 days after the demonstration discussed in Section VI.C.2.c.(ii) is disapproved by the Division.

VI.C.2.d. Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly.

VI.C.3. Testing and Monitoring Procedures

Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60 (September 14, 1989). The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound.

VI.C.4. Monitoring, Recordkeeping, Reporting

VI.C.4.a. Monitoring

VI.C.4.a.(i) The owner or operator of a petroleum refinery subject to this regulation shall conduct a monitoring program consistent with the following provisions:

VI.C.4.a.(i)(A) Monitor yearly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(A)(1) Pump seals; and

VI.C.4.a.(i)(A)(2) Piping valves in light liquid VOC service; and

VI.C.4.a.(i)(A)(3) Process drains; and

VI.C.4.a.(i)(A)(4) Heat-exchanger body flanges; and

VI.C.4.a.(i)(A)(5) Other accessible flanges in VOC service.

VI.C.4.a.(i)(A)(6) Components in heavy liquid VOC service are exempt from requirements of this Section VI.C.4.a.(i)(A).

VI.C.4.a.(i)(B) Monitor quarterly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(B)(1) Compressor seals; and

VI.C.4.a.(i)(B)(2) Piping valves in gaseous service; and

VI.C.4.a.(i)(B)(3) Pressure relief valves in gaseous service.

VI.C.4.a.(i)(C) Monitor at least weekly by visual methods all pump seals.

VI.C.4.a.(i)(D) Monitor within 24 hours with a VOC detector and make record of any component from which VOC liquids are observed leaking.

VI.C.4.a.(i)(E) Components in heavy liquid VOC service shall be monitored by the method referenced in Section VI.C.3. within five days if evidence of a potential leak is found by visual, audible, olfactory, or any other detectable method.

VI.C.4.a.(ii) Inaccessible valves and flanges shall be monitored annually or, as a minimum, at unit shutdown using the procedures of VI.C.2.a.(v). Pressure relief devices which are connected to an operating flare header or vapor recovery device, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Section VI.C.4.a.(i).

VI.C.4.a.(iii) The owner or operator of a petroleum refinery, upon the detection of a leaking component as defined in Section VI.C.2.a.(iii), shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired. In addition, the owner or operator shall log the leak (including those leaks immediately repaired), per the requirements of Sections VI.C.4.b.(i) through (iii).

VI.C.4.b. Recordkeeping

VI.C.4.b.(i) The owner or operator of a petroleum refinery shall maintain a leaking components monitoring log which shall contain at a minimum, the following data:

VI.C.4.b.(i)(A) The name of the process unit where the component is located.

VI.C.4.b.(i)(B) The type of component (e.g., valve, seal).

VI.C.4.b.(i)(C) The tag number of the component.

VI.C.4.b.(i)(D) The date on which a leaking component is discovered.

VI.C.4.b.(i)(E) The date on which a leaking component is repaired.

VI.C.4.b.(i)(F) The date and instrument reading found during the recheck procedure subsequent to repairing a leaking component.

VI.C.4.b.(i)(G) A record of the calibration of the monitoring instrument.

VI.C.4.b.(i)(H) Those leaks that cannot be repaired until turnaround.

VI.C.4.b.(i)(I) The total number of components checked and the total number of components found leaking.

VI.C.4.b.(i)(J) The total number of components subject to Section VI.C.2.a.(v) which upon retest were still leaking as defined in Section VI.C.3.

VI.C.4.b.(ii) Copies of the monitoring log shall be retained by the owner or operator for a minimum of two (2) years after the date on which the record was made or report prepared.

VI.C.4.b.(iii) Copies of the monitoring log shall be made available to the Division upon oral or written request.

VI.C.4.c. Reporting

The owner or operator of a petroleum refinery, upon the completion of each yearly and/or quarterly monitoring procedure, shall:

VI.C.4.c.(i) Submit a report to the Division by the 15th day of February, May, August, and November that lists all leaking components that were located during the previous three (3) calendar months (quarter), but not repaired within fifteen (15) working days, all leaking components awaiting unit turnaround, the total number of components inspected, and the total number of components found leaking.

VI.C.4.c.(ii) Submit a signed statement with the report attesting to the fact that, with the exception to those leaking components listed in Section VI.C.4.b.(i)(H), all monitoring and repairs were performed as stipulated in the monitoring program.

VII. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities

VII.A. General Provisions

VII.A.1. Applicability

This section is applicable to all gasoline terminals, gasoline bulk plants, and gasoline dispensing facilities (e.g., service stations) which are located in ozone nonattainment areas and which must have a vapor collection system pursuant to Section IV. and other applicable rules.

VII.A.2. Exemptions

This section is not applicable to those operations involving transfer of gasoline from gasoline dispensing facilities to motor vehicle fuel tanks nor to other dispensing operations at such facilities.

VII.A.3. Definitions

For the purpose of this section, the following definitions apply:

VII.A.3.a. "Gasoline Dispensing Facility" means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks, (e.g., service stations, fleet pumps, etc.)

VII.A.3.b. "Gasoline Transport Truck" means tank trucks or trailers equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants or gasoline terminals.

VII.A.3.c. "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

VII.B. Specific Provisions

VII.B.1. The operator of a vapor collection system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents:

VII.B.1.a. Gauge pressure from exceeding 33.6 torr (18 inches of H2O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H2O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility.

VII.B.1.b. A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," December 1978, EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

VII.B.1.c. Avoidable liquid or vapor leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

VII.B.1.d. Division representatives may monitor for excessive back pressure as defined by Section VII.B.1.a. and vapor leakage as is defined by Section VII.B.1.b. or by detection methods incorporating sight, sound, and smell.

VII.B.2. Repairs and Modifications

VII.B.2.a. The operator shall within fifteen (15) days, repair and retest a vapor collection system that exceeds the pressure limits (Section VII.B.1.a.), excepting that;

VII.B.2.b. Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion.

Appendix B Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks

I. Drop Tube Specifications. Submerged fill is specifically required. The drop tube must extend to within 15.24 cm (6 in.) of the tank bottom.

II. Vapor Hose Return. Vapor return line and any manifold must be minimum 7.6 cm (3 in.) ID. All tanks must be provided with individual overfill protection. (Liquid must not be allowed in the vent line or vapor recovery line.) Disconnect on liquid line should assure that all liquid in the hose is drained into the storage tank. The requirements for overfill protection as specified may be waived for existing storage tanks when it is demonstrated to the satisfaction of the appropriate local Fire Marshal, and where applicable, the State Oil Inspection Office that the installation of overfill protection devices on existing tanks is physically not possible.

III. Size of Vapor Line Connections. For separate vapor lines, nominal three inch (7.6 cm) or larger connections must be utilized at the storage tank and truck. However, short lengths of 2-inch (5.1 cm) vertical pipe no greater than 91.4 cm (3 ft.) long are permissible if the fuel delivery rate is less than 400 gallons per minute.

Where concentric (coaxial) connections are utilized, a 45 cm2 (7 sq. in.) area for vapor return shall be provided. Four-inch concentric designs are acceptable only when using a venturi-shaped outer tube or where normal drop rate of 1,700 liters per minute (450 gpm) is reduced by at least 25%. Six-inch (15.24 cm) risers should be installed in new stations with concentric connections.

IV. Type of Liquid Fill Connection. Vapor tight caps are required for the liquid fill connection for all systems. A positive closure utilizing a gasket is necessary to prevent vapors from being emitted at ground level. Cam-lock closures meet this requirement. Dry break closures are preferred.

V. Tank Truck Inspection. Tank trucks are specifically required to be vapor-tight and to have valid leak-tight certification. The visual inspection procedure must be conducted at least once every six months to ensure properly operating manifolding and relief valves, using the test procedure of Section IV.D.3.b.

VI. Dry Break on Underground Tank Vapor Riser. Dry-break closures are required to assure transfer of displaced vapors to the truck and to prevent ground-level, gasoline-vapor emissions caused by failure to connect the vapor return line to the underground tanks (closure on riser to mate with opening on hose). These devices keep the tank sealed until the hose is connected to the underground tank. Concentric couplers without dry-breaks are required to have a dry-break on the vapor line connection to the coupler itself, rather than on the rise pipe from the storage tank. The liquid fill riser should be provided with a gap having a positive closure (threaded or latched).

VII. Equipment Ensuring Vapor-Hose Connection during Gasoline Deliveries. An equipment system aboard the tank truck shall insure (barring deliberate tampering) that a vapor return hose is connected from the truck's vapor return line to the tank receiving gasoline.

VIII. Vent Line Restriction Devices. Vent line restriction devices are required. If the liquid fill line were attached to the underground tank and the vapor return line were disconnected, then dry break closures would seal the vapor return path to the truck, forcing all vapors out the vent line. In such instances, a restriction device on this vent line greatly reduces fill rate, warning the operator that the vapor line is not connected.

Pressure/vacuum (PV) vent valves installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water.

IX. Fire and Safety Regulations. All new or modified installations must comply in their entirety with all code requirements including NFPA, Pamphlet 30 (fiberglass is preferred for new manifold lines). For any questions concerning compliance, please contact State Oil Inspection or your local Fire Marshal.

X. State Oil Inspection. Requirements of the State Oil Inspection office make accurate measurements of the liquid in the underground tank necessary. Vapor-tight gauging devices will be required in all systems designed such that a pressure other than atmospheric will be held or maintained in the storage tank. The volume of liquid in the tanks maintained at atmospheric pressure may be determined with a stick through the submerged drop tube or through a separate submerged gauging tube extending to within 15.24 cm (6 in.) of the tank bottom.

Appendix C Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants

I. Storage Tank Requirements:

A. Drop Tube Specification: Underground tanks must contain a drop tube that extends to within six inches (15.24 cm) of the tank bottom. All top loaded above-ground tanks must contain a similar drop tube. Above-ground tanks using bottom loading, where the inlet is flush with the tank bottom, must meet the submerged fill requirement.

B. Size of Vapor Lines from Storage Tanks to Loading Rack: See nomograph (Attachment 1). NOTE: Affected sources are free to choose a pipe diameter different from the one suggested by the nomograph if sufficient justification and documentation is presented.

C. Pressure Relief Valves: All pressure relief valves and valve connections must be checked periodically for leaks, and be repaired as required. The relief valve pressures should be set in accordance with Sections 2-2.5.1 and 2-2.7.1 inclusive of the current National Fire Protection Agency Pamphlet Number 30.

D. Liquid Level Check Port: Access for checking liquid level by other than a vapor-tight gauging system shall be vapor-tight when not being used. Tank level shall be checked prior to filling to avoid overfills.

E. Miscellaneous Tank Openings: All other tank openings, e.g., tank inspection hatches, must be vapor tight when not being used, and must be closed at all times during transfer of fuel.

F. Storage Tank Overfill Protection: Except for concentric (coaxial) delivery systems, underground tanks must have ball check valves (stainless steel ball). Tanks with concentric delivery systems must have Division-approved overfill protection, (e.g., cutoff pressure-switch in vent line).

II. Loading Rack Requirements:

A. Loading Specification: A vapor-tight bottom-loading or top-loading system using submerged fill with a positive seal, e.g., the Wiggins (tm) system, is required. NOTE: Bulk plants delivering solely to exempt accounts are required to have submerged fill, but loading need not be vapor-tight.

B. Dry-Break on Storage Tank Vapor Return Line: A dry-break is required to prevent ground-level gasoline vapor emissions during periods when gasoline transfer is not being made. This device keeps the tank sealed until the vapor return hose is connected.

III. Tank Truck* Requirements:

A. Vapor Return Modification: Tank trucks must be modified to recover vapors during loading and unloading operations. NOTE: Tank trucks making deliveries solely to exempt accounts do not require this modification. However, 97% submerged fill is required when top loading.

B. Loading Specifications: Bottom loading or top loading using submerged fill with a positive seal is required for tank trucks modified for vapor recovery. NOTE: When loading a tank truck with this modification without the vapor return hose connected (this is allowed at bulk plants servicing exempt accounts returning without collected vapors in the tank), the requirements of National Fire Protection Agency Pamphlet Number 385, "Loading and Unloading Venting Protection in Tank Vehicles, Section 2219, Paragraph c", must be met.

C. Vapor Return Hose Size: A minimum three-inch (7.6 cm) ID vapor return hose is required.

D. Tank Truck Inspection: Tank trucks are required to be vapor-tight and have valid leak-tight certification. Periodic visual inspection is necessary to insure properly operating manifolding and relief valves.

* The term "tank truck" is meant to include all trucks with tanks used for the transport of gasoline, such as tank wagons, account trucks and transport trucks.

PART C Surface Coating, Solvents, Asphalt, Graphic Arts and Printing, and Pharmaceuticals

I. Surface Coating Operations

I.A. General Provisions

I.A.1. Definitions, unless otherwise specified in Sections I.B. through I.O.

I.A.1.a. "Coating" means a protective, functional or decorative film applied in a thin layer to a surface. This term often applies to paints such as lacquers or enamels, but is also used to refer to films applied to paper, plastics, or foils.

I.A.1.b. "Coating Applicator" means an apparatus used to apply a surface coating.

I.A.1.c. "Coating Line" means an operation which includes both (1) a coating applicator and (2) device(s) and/or area(s) to accomplish one or more of the following processes: flash-off, drying, curing, heat-setting and/or polymerization.

I.A.1.d. "Coating Solids" means that portion of a surface coating, which remains after volatile components have escaped.

I.A.1.e. "Final Repair Application" means that application of surface coating specifically intended to repair damage and imperfections in existing surface coats.

I.A.1.f. "Finished Coating Solids" means those coating-solids that remain on a coated substance after completion of all production processes.

I.A.1.g. "Flash-off Area" means the space between the application area and the oven.

I.A.1.h. "Prime Coat" (also termed "primer") means the first film of coating applied in a multiple-coat operation.

I.A.1.i. "Single Coat" means a single film of coating applied directly to the metal substrate, omitting the primer application.

I.A.1.j. "Surface Coating" means a liquid, liquefiable, or mastic composition which is converted to a solid (or semi-solid) protective, decorative, or adherent film or deposit after application as a thin layer or by impregnation. In a machine which has both coating and printing units, all units shall be considered as performing a printing operation. Such a machine is subject to the standards governing graphic arts, and thus is not covered by coating standards.

I.A.1.k. "Surface Coating Oven" means a chamber within which heat is used to bake, cure, polymerize, and/or dry a surface coating.

I.A.1.l. "Topcoat" means the final film of coating applied in a multiple-coat operation.

I.A.2. Abbreviations

I.A.2.a. Kg/lc shall be the abbreviation for: kilograms of solvent VOC per liter of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.2.b. Lb/gc shall be the abbreviation for: (avoirdupois) pounds of solvent VOC per gallon of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.3. Test Methods and Procedures

I.A.3.a. The owner or operator of any VOC source required to comply with this section shall, at their own expense, demonstrate compliance using EPA reference method 24 of 40 CFR Part 60 (September 14, 1989) for surface coatings, and reference method 25 and reference methods 1 through 4 (September 14, 1989) for add-on controls.

I.A.3.b. The test protocol should be in accordance with the requirements of the Air Pollution Control Division Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No test shall be conducted without prior approval from the Division.

I.A.3.c. The Division may use independent tests to verify test data submitted by the source operator or owner. The test methods shall be those listed in Section I.A.3.a. and the Division test results shall take precedence.

I.A.3.d. The Division may accept, instead of the testing required in this section, a certification by the manufacturer of the composition of the coatings if supported by actual batch formulation records. The owner or operator of the VOC source required to comply with this section shall obtain certification from the coating manufacturer(s) that the test method(s) used for determination of VOC content meet the requirements specified in Section I.A.3.a. The owner or operator shall have this certification readily available to Division personnel, in order to allow the results to be used in the daily compliance calculations specified in Section I.A.10.

I.A.3.e. The performance of add-on control device equipment shall be established with the required test methods of I.A.3.a. at equipment startup, and after major modification to the control equipment. Baseline operating parameters shall be established during the satisfactory (i.e. in-compliance) operation of the control equipment, including operation during all anticipated ranges of process throughput. During subsequent process operation, the owner or operator shall maintain the operating conditions of the add-on controls as close to these baseline conditions as possible. If serious operational problems with an add-on control system are evidenced from the daily monitoring required by Section I.A.8.b. (such problems may be indicated by changes from baseline conditions), repeat performance tests may be required by the Division, as necessary.

I.A.4. Sampling

To determine compliance with applicable surface coating standards, samples shall be taken from the coating as freshly delivered to the reservoir of the coating applicator.

I.A.5. Alternative compliance methods for processes and operations

For each process specified in Sections I.B. through I.N. the emission limits designated for that process shall be achieved by:

I.A.5.a. Use of coatings with proportions of VOC less than or equal to the maximums specified by the applicable section of this regulation; or

I.A.5.b. Use of the specified equipment and procedures prescribed by the applicable section of this regulation; or

I.A.5.c. Use of an alternative means of control which satisfies the requirements of Section I.A.5.e., I.A.5.f., and Part A, Section II.D.; or

I.A.5.d. Use of crossline averaging. The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met. In addition, the following requirements apply:

I.A.5.d.(i) The actual reduction shall be equivalent to the actual reduction that would be achieved on a line-by-line basis.

I.A.5.d.(ii) Credit shall not be received for downtime, however, credit is allowed for enforceable production limits.

I.A.5.d.(iii) Crossline averaging shall be used only across lines in the same control technique guidance group.

I.A.5.d.(iv) The emission trading policy shall be met on a daily weighted average.

I.A.5.d.(v) Sources subject to best available control technology (BACT) and lowest achievable emission rate (LAER) requirements shall not use cross line averaging.

I.A.5.d.(vi) VOC emissions shall be expressed as lbs/gallons solids to determine reduction over baseline (lb VOC/lb solids for graphic arts).

I.A.5.d.(vii) Organisol and plastisol coatings shall not be used to bubble emissions from vinyl surface or automobile topcoating operations.

I.A.5.d.(viii) Before crossline averaging may be used, the control methodology shall be approved as a revision to the State Implementation Plan.

I.A.5.e. The design, operation and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Unless the capture system meets the requirements for a total enclosure as specified in the New Source Performance Standard for the Magnetic Tape Manufacturing Industry, 53FR38892, October 3, 1988, or unless Division approved material balance techniques are used to adequately determine overall VOC capture and destruction/recovery efficiency, the efficiency of the capture system shall be determined by test methods approved as a revision to the State Implementation Plan. Testing for capture efficiency shall be performed on a case-by-case basis as required by the Division. The requirements of Sections I.A.3.e. and I.A.8.b. shall apply to the capture and control device system. When capture and control device efficiency must be independently determined, the overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

I.A.5.f. Sources which use add-on controls, crossline averaging, or an approved alternative control strategy instead of low solvent technology to meet the applicable emission limit shall meet the equivalent VOC emission limit, on the basis of solids applied (lb VOC/gal solids applied, or lb VOC/lb solids applied, for graphic arts sources). Appendix E sets forth the procedure for converting emission limits and lists equivalent limits for various coating operations.

I.A.5.g. Owners or operators of sources which use a carbon adsorption system shall provide for the proper disposal or reuse of all VOC recovered.

I.A.6. Exemptions

I.A.6.a. The requirements of this Section I. do not apply to sources used exclusively for chemical or physical analysis or determination of product quality and commercial acceptance, provided;

I.A.6.a.(i) the operation of the source is not an integral part of the production process; and

I.A.6.a.(ii) the emissions from the source do not exceed 363 kilograms (800 lbs.) in any calendar month; and

I.A.6.a.(iii) the exemption is approved in writing by the Division.

I.A.6.b. The requirements of Sections I.C., D., E., F., G., H., I., L. and M. are not applicable to sources whose actual emissions, including fugitive emissions, before add-on controls, are less than 6.8 kilograms (15 lbs.) per day and less than 1.4 kilograms (3 lbs.) per hour. Emissions from all sources within the same control technique guidance group shall be totaled to determine actual emissions.

I.A.7. Fugitive emission control

I.A.7.a. Control techniques and work practices shall be implemented at all times to reduce VOC emissions from fugitive sources. Control techniques and work practices include, but are not limited to:

I.A.7.a.(i) tight-fitting covers for open tanks;

I.A.7.a.(ii) covered containers for solvent wiping cloths;

I.A.7.a.(iii) proper disposal of dirty cleanup solvent.

I.A.7.b. Emissions of organic material released during clean-up operations, disposal, and other fugitive emissions shall be included when determining total emissions, unless the source owner or operator documents that the VOCs are collected and disposed of in a manner that prevents evaporation to the atmosphere.

I.A.8. Recordkeeping, Reporting, and Monitoring

I.A.8.a. If add-on control equipment is used, continuous monitors of the following parameters shall be installed, calibrated, and operated at all times that the associated control equipment is operating:

I.A.8.a.(i) exhaust gas temperature of all incinerators;

I.A.8.a.(ii) temperature rise across a catalytic incineration bed;

I.A.8.a.(iii) breakthrough of VOC on a carbon adsorption unit;

I.A.8.a.(iv) any other monitoring and/or recording device, maintenance and/or control-media-replacement schedule(s) specified on a case-by-case basis by the Division.

I.A.8.b. If add-on control equipment is used, in addition to the requirements of Section I.A.8.a., the following information and any other necessary information, as determined applicable for each source by the Division, shall be monitored and recorded daily in order to assure continuous compliance. The substitution of continuous recordings for daily recording may be allowed by the Division.

I.A.8.b.(i) For the capture system: fan power use, duct flow, duct pressure.

I.A.8.b.(ii) For carbon adsorbers: bed temperature, bed vacuum pressure, pressure at the vacuum pump, accumulated time of operation, concentration of VOC in the outlet gas, solvent recovery.

I.A.8.b.(iii) For refrigeration systems: compressor discharge and suction pressures, condenser fluid temperature, solvent recovery.

I.A.8.b.(iv) For incinerator systems: exhaust gas temperature, temperature rise across a catalytic incinerator bed, flame temperature, accumulated time of incinerator.

I.A.8.c. Recordkeeping procedures shall follow the guidance in "Recordkeeping Guidance Document for Surface Coating Operations and the Graphic Arts Industry," July 1989, EPA 340/1-88-003.

I.A.9. Required and Prohibited Acts

I.A.9.a. No owner or operator of a source of VOCs subject to this section shall operate, cause, allow or permit the operation of the source, unless:

I.A.9.a.(i) For each category of surface coating as specified in Sections I.B. through I.M., the owner or operator of a surface coating line or facility subject to that section does not cause, allow or permit the discharge into the atmosphere of any VOCs in excess of the specified emission limit, calculated as delivered to the coating applicator or as applied to the substrate, whichever is greater.

I.A.9.a.(ii) The owner or operator of a surface coating operation maintains and operates surface coating operations in a manner consistent with good air pollution control practices for minimizing emissions, such as, but not limited to, coating application methods capable of achieving a transfer efficiency achieved by HVLP spraying.

I.A.10. Compliance Calculation Procedures

I.A.10.a. Compliance with this section shall be determined on a daily basis. Sources may request a revision to the State Implementation Plan for longer times for compliance determination.

I.A.10.b. Compliance calculation procedures shall follow the guidance in "Procedure for Certifying Quantity of Volatile Organic Compounds Emitted by Paint, Ink, and Other Coatings," December 1984, EPA-450/3-84/019. In addition, for add-on controls or other compliance alternatives, calculation procedures shall follow the guidance of Section I.A.5.f.

I.A.11. The requirements of Sections I.A.1. through I.A.10. apply to each category of surface coating as specified in Sections I.B. through I.M. The requirements of Sections I.A.7. through I.A.10. apply to the category in Section I.N. The requirements of Sections I.A.1. through I.A.9 apply to the category in Section I.O.

I.A.12. The Division shall approve utilization of alternative compliance methods to the following sources pursuant to this Section I.

I.A.12.a. Lexmark International, Inc. shall be allowed to utilize the alternative compliance method of crossline averaging for processes and operations within the Manufactured Metal Parts and Metal products (Subgroup L) and within the Plastic Film Coating Operations (Subgroup J). The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met, and utilization of the alternative compliance method shall be subject to the following generic conditions, which shall be written and specifically described as enforceable permit terms and conditions in its permits:

I.A.12.a.(i) The alternative compliance method shall result in an actual reduction that is equivalent to the actual reduction that would otherwise be achieved on a line-by-line basis pursuant to this Regulation Number 7.

I.A.12.a.(ii) Credit shall not be received for downtime; however, credit is allowed for emission reductions from enforceable production limits.

I.A.12.a.(iii) Cross line averaging shall be used only across lines of the same control technique guidance group. Lexmark shall use cross line averaging between Metal Parts and Metal Products lines or between Plastic Film Coating lines. Lexmark shall not use cross line averaging where the emissions from Plastic film coating lines are averaged with Metal Parts and Metal Products lines.

I.A.12.a.(iv) The emission trading policy set forth in Regulation Number 3, Part A, Section V., shall be met on a daily weighted average.

I.A.12.a.(v) Sources subject to Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) shall not use cross line averaging.

I.A.12.a.(vi) To determine reduction over baseline, VOC emissions shall be expressed according to Section I.A.5.f., as lbs/gallons solids.

I.A.12.a.(vii) Monthly records shall be kept at the source to verify ongoing compliance with these conditions. The recordkeeping format shall be approved by the Division.

I.A.12.a.(viii) An annual report demonstrating ongoing compliance with this regulation and all permit terms shall be filed with the Division. The report format shall be approved by the Division and specifically described in the permit.

I.A.12.a.(ix) The Division shall issue a permit with federally enforceable terms and conditions to Lexmark limiting Lexmark's alternative compliance method emissions to those allowable under Section I.L. and Section I.J.

I.A.12.a.(x) Commercial and Product quality control laboratory equipment are exempt from APEN filing and construction permit requirements under Regulation Number 3, Part A, Section II.D.1.(i), and Regulation Number 3, Part B, Section II.D.1.a.; and from construction permit requirements under Regulation Number 3, Part B, Section II.D.1.(i). Qualifying sources shall be exempt from Regulation Number 7, Section I. A.6.

I.A.12.a.(xi) Nothing in the alternative compliance method is intended to relax any emissions limitation of this Regulation Number 7.

I.B. Automobile and Light-Duty Truck Assembly Plants

I.B.1. Definitions

I.B.1.a. "Application Area" means the area where the surface coating is applied by spraying, dipping or flow coating.

I.B.1.b. "Automobile" means a passenger motor-vehicle or a derivative of same, capable of seating twelve (12) or fewer passengers, and having at least two driven wheels.

I.B.1.c. "Automobile Assembly Facility" means a facility where parts (including assembled or partially assembled components) of automobiles are received, and finished automobiles are produced, partially or wholly by an assembly line.

I.B.1.d. "Light-Duty Truck" means any motor vehicle rated at 8,500 pounds (3,855 kilograms) gross vehicle weight or less, and having at least two driven wheels, which is designed primarily for purposes of transportation of property or is a derivative of such vehicles. It includes, but is not limited to, pickup trucks, vans, and window vans rated at 8,500 pounds' gross vehicular weight or less.

I.B.1.e. "Light-Duty Truck Assembly Facility" means a facility where parts (including assembled or partially assembled components) of light-duty trucks are received, and finished light-duty trucks are produced, partially or wholly by an assembly line.

I.B.2. Applicability

This section applies to all assembly and subassembly lines in an automobile or light-duty truck assembly facility, including those for frames, small parts, wheels, and main body parts. This section applies only to the manufacture of new vehicles.

I.B.3. Emission Limitations

	Kg/lc	Lb/gc
Prime application, flashoff area, and oven	0.23	1.9
Topcoat application area, flashoff area, and oven	0.34	2.8
Final repair application, flashoff area and oven	0.58	4.8

I.B.4. Coatings other than primer, surfacer (guidecoat), topcoat and final repair shall be considered under the miscellaneous metal parts Section I.L.

I.B.5. For topcoat application, if a complying coating is not used to meet the emission limit of Section I.B.3, then:

I.B.5.a. the alternate method shall meet an emission limit of 15.1 lb VOC/gal. solids deposited on the coated part; and

I.B.5.b. compliance shall be determined on a daily weighted average basis.

I.B.6. Topcoat operation shall include all spray booths, flash-off areas and ovens in which topcoat is applied, dried and cured, except for final offline repair.

I.C. Can Coating Operations

I.C.1. Definitions

I.C.1.a. "Can Coatings" means any coatings containing organic materials and applied -- or intended for application -- by spray, roller, or other means onto the inside and/or outside surfaces of formed cans and components of cans.

I.C.1.b. "End Sealing Compound" means a substance which is coated onto can ends and which functions as a seal when the end is assembled onto the can.

I.C.1.c. "Exterior Base Coat" means a coating applied to the exterior of a can to provide protection to the metal and/or to provide background for any lithographic or printing operation.

I.C.1.d. "Interior Base Coat" means the initial coating applied to the interior surface of a can by roller coater or spray.

I.C.1.e. "Interior Body Spray" means a coating sprayed onto the interior surface of the can body to provide a protective film between the can and its contents.

I.C.1.f. "Overvarnish" means a coating applied directly over ink to reduce the coefficient of friction, provide gloss, protect against abrasion, enhance product quality, and protect against corrosion.

I.C.1.g. "Three-Piece Can Side Seam Spray" means a coating sprayed onto the interior and/or exterior of a can body seam on a three-piece can to protect the exposed metal.

I.C.1.h. "Two-Piece Can Exterior End Coat" means a coating applied to the exterior of the bottom end of a two-piece can.

I.C.2. Applicability

This section applies to coating applicator(s), and oven(s) of sheet can or end coating lines involved in sheet basecoat (exterior and interior) and over varnish, two-and three-piece can interior body spray, two-piece can exterior end (spray or roll coat), three-piece can side-seam spray, and end sealing compound operations.

I.C.3. Emission Limitations

Can Coating	**Kg/lc**	**Lb/gc**
Sheet base coat (exterior and interior) and overvarnish two-piece can exterior (base coat and overvarnish)	0.34	2.8
Two and three-piece can interior body spray, two-piece can exterior end (spray or roll coat)	0.51	4.2
Three-piece can side-seam spray	0.66	5.5
End sealing compound	0.44	3.7
Any additional coats	0.51	4.2

I.D. Coil Coating Operations

I.D.1. Definitions

I.D.1.a. “Coil Coating” means any surface coating applied by spray, roller, or other means onto one or both surfaces of flat metal sheets or strips that come in rolls or coils.

I.D.1.b. “Quench Area” means a chamber where the hot metal exiting the oven is cooled by either a spray of water or a blast of air followed by water cooling.

I.D.2. Applicability

This section applies to the coating applicator(s), oven(s), and quench area(s) of coil coating operations involved in primer, intermediate, top-coat or single-coat operations.

I.D.3. Emission Limitations:

Coil Coating	Kg/lc	Lb/gc
Any coat (primer, intermediate coat, topcoat, single coat)	0.31	2.6

I.E. Fabric Coating Operations

I.E.1. Definitions

I.E.1.a. “Fabric Coating" means the process of coating or impregnating the full, usable surface of a fabric web or sheet to impart properties that are not initially present such as strength, stability, water or acid repellency, or appearance. "Fabric Coating" excludes those processes normally included under fabric finishing (e.g. dyeing, treating for stain and wrinkle resistance, etc.).

I.E.2. Applicability

This section applies to fabric coating lines which includes, but is not limited to, coaters and drying ovens.

I.E.3. Emission Limitations

	Kg/lc	Lb/gc
Fabric Coating Line	0.35	2.9

I.F. Large Appliance Coating Operations

I.F.1. Definition

I.F.1.a. "Large Appliances” includes doors, cases, lids, panels, interior support parts, and any other large (greater than one square decimeter (15.5 square inches)) coated surfaces of residential and commercial washers, dryers, ovens, ranges, refrigerators, freezers, water heaters, dishwashers, trash compactors, air conditioners, and all other products under SIC Code 363 according to the "Standard Industrial Classification Manual", Executive Office of the President, Office of Management and Budget, designated by convention of the industry as large appliances.

I.F.2. Applicability

This section applies to all large appliance coating lines.

I.F.3. Emission Limitations

	Kg/lc	Lb/gc
Large Appliance Coating Line; prime, single or topcoat application area, flashoff area, and oven	0.34	2.8

I.G. Magnet Wire Coating Operations

I.G.1. Definition

I.G.1.a. "Magnet Wire Coating" means those operations which apply a coating of electrically insulating varnish or enamel (or similar substance) to wire which is known as "magnet wire." Magnet wire is usually copper or aluminum, and is used for electric motors, generators, transformers, magnets, and related products.

I.G.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of magnet wire coating operations.

I.G.3. Emission Limitations

	Kg/lc	Lb/gc
Magnetic wire coating operation	0.20	1.7

I.H. Metal Furniture Coating Operations

I.H.1. Definitions

I.H.1.a. "Metal Furniture" means furnishings commonly considered furniture, for domestic, business, and/or institutional use, which have one or more essential, major components made of metal. "Metal furniture" includes, but is not limited to, tables, chairs, wastebaskets, beds, desks, lockers, shelving, cabinets, room dividers, clothing racks, chests of drawers, and sofas.

I.H.1.b. "Metal Furniture Coating" means applying a "surface coating" to "metal furniture" as defined. It excludes coating of non-metal components.

I.H.2. Applicability

This section applies to all metal furniture coating lines.

I.H.3. Emission Limitations

	Kg/lc	Lb/gc
Metal Furniture Coating Line: All coats (including prime, single, and topcoat)	0.36	3.0

I.I. Paper Coating Operations

I.I.1. Definition

"Paper Coating" means impregnating or applying a uniform layer of "surface coating" to paper. It includes, but is not limited to, the production of: coated, glazed, decorated, and varnished paper; carbon and pressure-sensitive copy papers; paper adhesive-labels and tapes; blue-print; photographic and copier paper. It also includes coating of metal foil such as gift wrap and packaging. Paper coating does not include impregnation using a batch dipping process.

I.I.2. Applicability

This section applies to paper coating lines, which includes, but is not limited to, coaters and drying ovens.

I.I.3. Emission Limitations

	Kg/lc	Lb/gc
Paper Coating Line	0.35	2.9

I.J. Plastic-Film Coating Operations

I.J.1. Definition

I.J.1.a. "Plastic-Film Coating" means applying a uniform layer of "surface coating" to a flexible web or sheet of thin plastic substance, excluding all rubbers and vinyl's* (polyvinyl chloride) except for the following two categories of vinyl products: (1) vinyl tapes and (2) vinyl's coated with an adhesive or pressure-sensitive coating. It includes, but is not limited to: plastic typewriter ribbons, photographic film, adhesive tapes, and magnetic recording tapes. (*see Section I.K.)

I.J.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of plastic-film coating lines.

I.J.3. Emission Limitations

	Kg/lc	Lb/gc
Plastic-Film Coating Line	0.35	2.9

I.K. Vinyl Coating Operations

I.K.1. Definition

"Vinyl Coating" means applying a uniform layer, decorative or protective topcoat to a vinyl (polyvinyl chloride) coated fabric or vinyl sheet. It includes printing of same. Excluded are*: (1) the coating of same with adhesive or pressure-sensitive coatings and (2) vinyl tapes. (*see Section I.J.)

I.K.2. Application

This section applies to vinyl coating lines which includes, but is not limited to, coaters and drying ovens.

I.K.3. Emission Limitations

	Kg/lc	Lb/gc
Vinyl Coating Line	0.45	3.8

I.L. Manufactured Metal Parts and Metal Products

I.L.1. General Provisions

I.L.1.a. Applicability

This section applies to the application area(s), flashoff area(s), oven(s), and drying areas including (but not limited to) air and forced air drier(s) used in the surface coating of the metal parts and products listed below. This section applies to prime coat, top coat, and single coat operations. This section is applicable to surface coating of manufactured metal parts and metal products which include:

I.L.1.a.(i) Large farm machinery (harvesting, fertilizing, and planting machines, tractors, combines, etc.);

I.L.1.a.(ii) Small-farm, lawn and garden machinery (lawn and garden tractors, lawn mowers, rototillers, etc.);

I.L.1.a.(iii) Small appliances (fans, mixers, blenders, crock pots, dehumidifiers, vacuum cleaners, etc.);

I.L.1.a.(iv) Commercial machinery (office equipment, computers and auxiliary equipment, typewriters, calculators, vending machines, etc.);

I.L.1.a.(v) Industrial machinery (pumps, compressors, conveyor components, fans, blowers, transformers, etc.);

I.L.1.a.(vi) Fabricated metal products (metal covered doors, frames, etc.);

I.L.1.a.(vii) Furniture hardware made of metal for use with non-metal furniture; and

I.L.1.a.(viii) Any other industrial category which coats metal parts or products under the standard industrial classification code of major group 33 (primary metal industries), major group 34 (fabricated metal products), major group 35 (non-electric machinery), major group 36 (electrical machinery), major group 37 (transportation equipment), major group 38 (miscellaneous instruments), and major group 39 (miscellaneous manufacturing industries), according to the "Standard Industrial Classification Manual" Executive Office of the President, Office of Management and Budget.

I.L.1.b. Exemptions

I.L.1.b.(i) This Section I.L. is not applicable to the surface coating of the following metal parts and products inasmuch as these are previously covered in Sections I.B., C., D., F., G., and H., respectively:

I.L.1.b.(i)(A) Automobiles and light-duty trucks

I.L.1.b.(i)(B) Metal cans

I.L.1.b.(i)(C) Flat metal sheets and strips in the form of rolls or coils

I.L.1.b.(i)(D) Large appliances

I.L.1.b.(i)(E) Magnet wire for use in electrical machinery

I.L.1.b.(i)(F) Metal furniture

I.L.1.b.(ii) This Section I.L. is not applicable to the following special purpose coatings:

I.L.1.b.(ii)(A) Division-approved exemptions for high performance coatings on a case-by-case basis.

I.L.1.b.(ii)(B) Full exterior repainting of automobiles and light-duty trucks if fewer than 18 vehicles are painted per day.

I.L.1.c. Definitions

For the purpose of this section, the following definitions apply:

I.L.1.c.(i) "Air Dried Coating" means coatings which are dried by the use of air or forced warm air at temperatures up to 90°C (194°F);

I.L.1.c.(ii) "Clear Coat" means a coating, which lacks color and opacity or a coating which is transparent;

I.L.1.c.(iii) "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, flashoff areas, air dryers and ovens;

I.L.1.c.(iv) "Extreme Environmental Conditions" means exposure to any of the following: temperatures consistently above 95°C, detergents, abrasive and scouring agents, solvents, and corrosive environments;

I.L.1.c.(v) "Extreme Performance Coatings" means coatings designed for extreme environmental conditions.

I.L.2. Provisions for Specific Processes

I.L.2.a. No owner or operator of a facility or operation engaging in the surface coating of manufactured metal parts or metal products may operate a coating application system subject to this regulation that emits VOC in excess of:

I.L.2.a.(i) Clear coatings: 0.52 kg/lc (4.3 lb/gc)

I.L.2.a.(ii) Extreme Performance Coatings: 0.42 kg/lc (3.5 lb/gc)

I.L.2.a.(iii) Air-Dried Coatings: 0.42 kg/lc (3.5 lb/gc)

I.L.2.a.(iv) Other coatings and systems: 0.36 kg/lc (3.0 lb/gc) delivered to a coating applicator for all other coatings and coating application systems.

I.L.2.b. If more than one emission limitation in Section I.L.2.a. applies to a specific coating, then the least stringent emission limitation shall be applied.

I.L.2.c. Pioneer Metal Finishing, Inc., a surface coating operation, is authorized pursuant to Regulation Number 3, Part A, Section V. and Regulation Number 7, Part A, Section II.D.1.a. to use up to twenty (20) tons of certified emission reduction credits of volatile organic compounds (VOC) as an alternative compliance method to satisfy the surface coating emission limitations of Regulation Number 7 in accordance with and upon demonstration of the conditions set forth below:

I.L.2.c.(i) Certified emission reduction credits for VOCs (methanol) to be used in this transaction were formerly owned by the Coors Brewing Company, registered and issued in Emissions Reduction Credit Permit 91AR120R on July 25, 1994;

I.L.2.c.(ii) Those emission reduction credits were originally obtained by Coors from Verticel, a company that produced honeycomb packaging material and was located within five miles of the PMF facility;

I.L.2.c.(iii) The use of these VOC emission reduction credits identified above shall be used to satisfy VOC limitations of certain specified surface coatings in excess of Control Technique Guidance as specified in Regulation Number 7, Section I.L.2.a. and Section I.A.6.b., and applicable to the Pioneer Metal finishing operations;

I.L.2.c.(iv) Such emission reduction credits identified above will be used by PMF to achieve compliance with Regulation Number 7 to compensate for ozone precursor emission of VOCs from non-compliant coatings which meet the emission trading requirements of Regulation Number 3, Part A, Section V. In order to satisfy the photochemical reactivity equivalency requirement of VOC trades, the methanol VOC ERCs will be reduced on a ratio of 1.1:1 for VOCs of toluene, ethylbenzene, xylene and ketones emitted from non-compliant coatings. All other VOCs involved in this transaction are considered to be of the same degree of photochemical reactivity;

I.L.2.c.(v) The requirement in Regulation Number 3, Part A, Section V.F.2. shall not apply to this transaction;

I.L.2.c.(vi) This transaction is only valid within the Denver/Boulder nonattainment area as described at 40 CFR 81, Subchapter C - Air Programs, Subpart C, Section 107 - Attainment Status Designations, Section 81.306 (February 16, 1995);

I.L.2.c.(vii) This transaction shall be calculated upon a pound for pound basis and averaged over a maximum 24-hour period.

I.L.2.c.(viii) This transaction shall be effective upon approval by the U.S. Environmental Protection Agency as a revision to the Colorado State Implementation Plan and after issuance of a State Construction Permit incorporating, but not limited to, the conditions and requirements of the Section;

I.L.2.c.(ix) This transaction may not be used to satisfy any current or future requirements of NSPS, BACT, LAER, or MACT requirements of HAPs which may apply to PMF, except that this transaction may be used to satisfy control technique guidance or RACT requirements contained in Regulation Number 7 which are applicable to PMF;

I.L.2.c.(x) This transaction shall not interfere with any applicable requirement concerning attainment and reasonable further progress in the Colorado State Implementation Plan or any other applicable requirements of the Clean Air Act;

I.L.2.c.(xi) This transaction shall be registered and enforced through a State Construction Permit issued to Pioneer Metal Finishing, Inc. containing, but not limited to the conditions and limitations set forth in this Section;

I.L.2.c.(xii) Such state Construction Permit issued to Pioneer Metal Finishing, Inc. shall specify, among other, things the necessary monitory, recordkeeping and reporting requirements to insure that the emission reduction credits are applied in accordance with the conditions and requirements of this Section;

I.L.2.c.(xiii) The state Construction Permit shall allow a daily maximum limitation of 160 lbs. of VOC emissions from non-compliant surface coatings and an annual limitation of 40,000 lbs. of non-compliant VOC emissions. The annual limitation shall be calculated on a 12-month rolling total calculated on the first day of each month using the previous 12 months.

I.L.2.c.(xiv) The state Construction Permit shall limit the VOC-HAP emissions to less than ten (10) per year of any one HAP or twenty-five (25) tons per year of any combination of HAP emissions; and

I.L.2.c.(xv) PMF will maintain records of daily and monthly totals of non-compliant surface coatings used in its operation and report such usages on an annual basis to the Division or as otherwise requested.

I.M. Flat Wood Paneling Coating.

I.M.1. Definitions

I.M.1.a. "Class II Hardboard Paneling Finish" means finishes which meet the specifications of Voluntary Product Standard PS-59-73 as approved by the American National Standards Institute.

I.M.1.b. "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, conveyers, flashoff areas, air dryers and ovens.

I.M.1.c. "Hardboard" is a panel manufactured primarily from inter-felted ligno-cellulosic fibers which are consolidated under heat and pressure in a hot press.

I.M.1.d. "Hardboard Plywood" is plywood whose surface layer is a veneer of hardwood.

I.M.1.e. "Natural Finish Hardwood Plywood Panels" means panels whose original grain pattern is enhanced by essentially transparent finishes frequently supplemented by fillers and toners.

I.M.1.f. "Printed Interior Panels" means panels whose grain or natural surface is obscured by fillers and basecoats upon which a simulated grain or decorative pattern is printed.

I.M.1.g. "Thin Particleboard" is a manufactured board 1/4 inch or less in thickness made of individual wood particles which have been coated with a binder and formed into flat sheets by pressure.

I.M.1.h. "Tileboard" means paneling that has a colored waterproof surface coating.

I.M.2. Applicability

This section applies to all flat wood manufacturing and surface finishing facilities that manufacture printed interior panels made of hardwood plywood and thin particle board; natural finish hardwood plywood panels, or hardboard paneling with Class II finishes. This section does not apply to the manufacture of exterior siding, tileboard, or particleboard used as a furniture component.

I.M.3. Emission Limitations

I.M.3.a. 2.9 kg per 100 square meters of coated finished product (6.0 lb/1,000 sq. ft.) from printed interior panels, regardless of the number of coats applied;

I.M.3.b. 5.8 kg per 100 square meters of coated finished product (12.0 lb/1,000 sq. ft.) from natural finish hardwood plywood panels, regardless of the number of coats applied; and

I.M.3.c. 4.8 kg per 100 square meters of coated finished product (10.0 lb/1,000 sq. ft.) from Class II finishes on hardboard panels, regardless of the number of coats applied.

I.N. Manufacture of Pneumatic Rubber Tires

I.N.1. Definitions

I.N.1.a. "Bead Dipping" means the dipping of an assembled tire bead into a solvent-based cement.

I.N.1.b. "Green Tires" means assembled tires before holding and curing have occurred.

I.N.1.c. "Green Tire Spraying" means the spraying of green tires, both inside and outside, with release compounds which help remove air from the tire during molding and prevent the tire from sticking to the mold after curing.

I.N.1.d. "Pneumatic Rubber Tire Manufacture" means the production of pneumatic rubber, passenger type tires on a mass production basis.

I.N.1.e. "Passenger Type Tire" means agricultural, airplane, industrial, mobile home, light and medium duty truck, and passenger vehicle tires with a bead diameter up to 20.0 inches and cross section dimension up to 12.8 inches.

I.N.1.f. "Tread End Cementing" means the application of a solvent-based cement to the tire tread ends.

I.N.1.g. "Undertread Cementing" means the application of a solvent-based cement to the underside of a tire tread.

I.N.1.h. "Water Based Sprays" means release compounds, sprayed on the inside and outside of green tires, in which solids, water, and emulsifiers have been substituted for organic solvents.

I.N.2. Applicability

This section applies to VOC emissions from the following operations in all pneumatic rubber tire facilities: undertread cementing, tread end cementing, bead dipping, and green tire spraying.

The provisions of this section do not apply to the production of specialty tires for antique or other vehicles when produced on an irregular basis or with short production runs. This exemption applies only to tires produced on equipment separate from normal production lines for passenger type tires.

I.N.3. Provisions for Specific Processes

I.N.3.a. The owner or operator of an undertread cementing, tread end cementing, or bead dipping operation subject to this regulation shall:

I.N.3.a.(i) Install and operate a capture system, designed to achieve maximum reasonable capture, up to 85 percent by weight of VOC emitted, from all undertread cementing, tread end cementing and bead dipping operations. Maximum reasonable capture shall be consistent with the following documents:

I.N.3.a.(i)(A) Industrial Ventilation, A Manual of Recommended Practices, 17th Edition, American Federation of Industrial Hygienists, 1982.

I.N.3.a.(i)(B) Recommended Industrial Ventilation Guidelines, U.S. Department of Health, Education and Welfare, National Institute of Occupational Safety and Health, January 1976.

I.N.3.a.(ii) Install and operate a control device that meets the requirements of one of the following:

I.N.3.a.(ii)(A) A carbon adsorption system designed and operated in a manner such that there is at least a 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.3.a.(ii)(B) An incineration system that oxidizes at least 90.0 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) which enter the incinerator to carbon dioxide and water.

I.N.4. The owner or operator of a green tire spraying operation subject to this regulation must implement one of the following means of reducing volatile organic compound emissions:

I.N.4.a. Substitute water-based sprays for the normal solvent-based mold release compound; or,

I.N.4.a.(i) Install a capture system designed and operated in a manner that will capture and transfer at least 90.0 percent of the VOC emitted by the green tire spraying operation to a control device; and, I.N.4.a.(ii) In addition to Section I.N.4.a.(i), install and operate a control device that meets the requirements of one of the following:

I.N.4.a.(ii)(A) a carbon adsorption system designed and operated in a manner such that there is at least 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.4.a.(ii)(B) an incineration system that oxidizes at least 90 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) to carbon dioxide and water.

I.N.5. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

I.N.6. Control devices shall meet the applicable requirements, including recordkeeping, of Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

I.N.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

I.O. Wood Products Coating

I.O.1. Definitions

I.O.1.a. “As Applied” means the VOC and solids content of the finishing material that is actually used for coating the substrate. It includes the contribution of materials used for in-house dilution of the finishing material.

I.O.1.b. “Cleaning Operation” means operations in which organic solvent is used to remove coating materials from equipment used in wood furniture manufacturing operations.

I.O.1.c. “Conventional Air Spray” means a spray coating method in which the coating is atomized by mixing it with compressed air at an air pressure greater than 10 pounds per square inch (gauge) at the point of atomization. Airless and air assisted spray technologies are not conventional air spray because the coating is not atomized by mixing it with compressed air. Electrostatic spray technology is also not considered conventional air spray because an electrostatic charge is employed to attract the coating to the workplace.

I.O.1.d. “Equipment Leak” means emissions of VOCs from pumps, valves, flanges, or other equipment used to transfer or apply finishing materials or organic solvents.

I.O.1.e. “Finishing Material” means a coating used in the wood furniture industry including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats.

I.O.1.f. “Finishing Operation” means those activities in which a finishing material, including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats, is applied to a substrate and is subsequently air-dried, cured in an oven, or cured by radiation.

I.O.1.g. "Organic Solvent" means a liquid containing VOCs that is used for dissolving or dispersing constituents in a coating, adjusting the viscosity of a coating, cleaning, or washoff. When used in a coating, the organic solvent evaporates during drying and does not become part of the dried film.

I.O.1.h. "Sealer" means a finishing material used to seal the pores of a wood substrate before additional coats of finishing material are applied. Washcoats, which are used in some finishing systems to optimize aesthetics, are not sealers.

I.O.1.i. "Strippable Booth Coating" means a coating that is applied to a booth wall to provide a protective film to receive overspray during finishing operations that is subsequently peeled off and disposed, and reduces or eliminates the need to use organic solvents to clean booth walls.

I.O.1.j. "Topcoat" means the last film-building finishing material applied in a finishing system. Non-permanent final finishes are not topcoats.

I.O.1.k. "Washcoat" means a transparent special purpose coating that has a solids content by weight of 12 percent or less. Washcoats are applied over initial stains to protect and control color and to stiffen the wood fibers in order to aid sanding.

I.O.1.l. "Washoff Operation" means those operations in which organic solvent is used to remove coating from a substrate.

I.O.1.m. "Wood Furniture" means any product made of wood, a wood product such as rattan or wicker, or an engineer wood product such as particleboard.

I.O.1.n. "Wood Furniture Component" means any part that is used in the manufacture of wood furniture including, but not limited to, drawer sides, cabinet doors, seat cushions, and laminated tops.

I.O.1.o. "Wood Furniture Manufacturing Operation" means the finishing, cleaning, and washoff operations associated with the production of wood furniture or wood furniture components.

I.O.2. Applicability

This section applies to wood furniture manufacturing operations with uncontrolled actual VOC emissions greater than or equal to 25 tons per calendar year.

Beginning July 1, 2021, this section applies to other wood products coating operations with uncontrolled actual VOC emissions greater than or equal to 50 tons per year (as of January 27, 2020, located in the 8-Hour Ozone Control Area).

I.O.3. Emission Limitations

I.O.3.a. The owner or operator of a wood furniture manufacturing or other wood products coating operation must limit VOC emissions from finishing operations by:

I.O.3.a.(i) Using topcoats with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids); or

I.O.3.a.(ii) Using a finishing system of:

I.O.3.a.(ii)(A) Sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids), as applied; and

I.O.3.a.(ii)(B) Topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied; or

I.O.3.a.(iii) For sources using acid-cured alkyd amino vinyl sealers or acid-cured alkyd amino conversion varnish topcoats:

I.O.3.a.(iii)(A) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and an acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied; or

I.O.3.a.(iii)(B) Use acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied, and sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids); or

I.O.3.a.(iii)(C) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied.

I.O.3.b. The owner or operator of a wood furniture manufacturing or other wood products coating operation must use strippable booth coatings with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids), as applied.

I.O.3.c. The owner or operator of a wood furniture manufacturing or other wood products coating operation must use compounds containing equal to or less than 8.0 percent by weight of VOC for cleaning spray booth components other than conveyors, continuous coaters and their enclosures, and/or metal filters, unless the spray booth is being refurbished. If the spray booth is refurbished (i.e., spray booth coating or other material used to cover the booth is being replaced), the owner or operator must use equal to or less than 1.0 gallon of organic solvent to prepare the booth prior to applying the booth coating.

I.O.4. Work Practices

I.O.4.a. In addition to complying with Sections I.A.7. and I.A.9., the owner or operator of a wood furniture manufacturing or other wood products coating operation must:

I.O.4.a.(i) Develop an operator training program that includes, at a minimum, appropriate application techniques, appropriate cleaning and washoff procedures, appropriate equipment setup and adjustment to minimize finishing material usage and overspray, and appropriate management of cleanup wastes;

I.O.4.a.(ii) Conduct monthly visual inspections of all equipment used to transfer or apply finishing materials or organic solvents for equipment leaks and repair equipment leaks within 15 working days, or within 3 months if the leaking equipment must be replaced by a new purchase;

I.O.4.a.(iii) Collect cleaning and washoff solvents into closed containers;

I.O.4.a.(iv) Use conventional air spray guns only to:

I.O.4.a.(iv)(A) Apply finishing materials with a VOC content equal to or less than 1.0 lb VOC/lb solids (1.0 kg VOC/kg solids), as applied;

I.O.4.a.(iv)(B) Touch-up and repair after completion of the finishing operation, after stain and before other finishing material, or to apply stain on a part for which it is technically or economically infeasible to use any other spray application technology.

I.O.5. Recordkeeping

I.O.5.a. The owner or operator of a wood furniture manufacturing or other wood products coating operation must keep the following records for five (5) years and make them available for inspection by the Division upon request:

I.O.5.a.(i) Records of calendar year VOC emission estimates demonstrating whether the wood furniture manufacturing operation means or exceeds the applicability threshold in Section I.O.2.;

I.O.5.a.(ii) Records of the operator training program;

I.O.5.a.(iii) Records of the date and results of the monthly equipment inspections and any repairs that were made;

I.O.5.a.(iv) Records such as, but not limited to, data sheets documenting how the as applied values were determined and safety data sheets or other analytical data from the manufacturer showing the VOC content of each sealer, topcoat, strippable booth coating, or cleaning booth compound subject to the emission limits in Section I.O.3.; and

I.O.5.a.(v) Monthly records of the quantity and type of organic cleaning and washoff solvent used.

II. Solvent Use

II.A. General Provisions

II.A.1. Applicability

The provisions of this section apply to cold cleaners, non-conveyorized vapor degreasers, conveyorized degreasers, industrial cleaning solvent operations, and other operations that use solvents. Open top vapor degreasers are a subset of non-conveyorized vapor degreasers. The owner or operator of a unit subject to this section shall ensure that no such unit is used unless the requirements of this section are satisfied. Section II.E. requirements are effective on January 1, 2017. Section II.F. requirements are effective on May 1, 2021.

II.A.2. Definitions

II.A.2.a. "Cold-Cleaner" means a container of non-aqueous liquid solvent held below its boiling point, which is designed, used, or intended for cleaning solid objects in a batch-loaded process. A "cold-cleaner" may have provisions for heating the solvent. It does not include vapor degreasers or continuously loaded conveyorized degreasers.

II.A.2.b. "Composite Partial Vapor Pressure" means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the "i"th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the "i"th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

II.A.2.c. "Conveyorized Degreaser" means an apparatus that performs degreasing or other cleaning functions through the use of non-aqueous liquid solvent and/or solvent vapors within a container, and which has a conveyor mechanism allowing continuous loading of items conveyed into and out of the solvent.

II.A.2.d. "Freeboard" in a vapor degreaser means the vertical distance from the top of the vapor zone (as established by normal operations within the specifications of the degreaser manufacturer) to the top of the degreaser. For cold-cleaners "freeboard" means the vertical distance from the surface of the solvent liquid to the top of the degreaser. If all sides are not even, the vertical distance to the top of the lowest side shall be used to make the determination of freeboard.

II.A.2.e. "Freeboard Ratio" means the ratio of the freeboard to the width of the solvent surface.

II.A.2.f. "Industrial Cleaning Solvent" means a VOC-containing liquid used to perform industrial cleaning solvent operations.

II.A.2.g. “Industrial Cleaning Solvent Operation” means the use of an industrial cleaning solvent for cleaning industrial operations such as spray gun cleaning, spray booth cleaning, large manufactured parts cleaning, equipment cleaning, floor cleaning, line cleaning, parts cleaning, tank cleaning, and small manufactured parts cleaning. Residential and janitorial cleaning are not considered industrial cleaning solvent operations.

II.A.2.h. "Non-Conveyorized Vapor Degreaser” means an apparatus, which uses non-aqueous solvent vapors within some type of container to degrease or otherwise clean solid objects in a batch-loaded process. It excludes continuously loaded conveyorized degreasers.

II.A.2.i. “Residential and Janitorial Cleaning” means the cleaning of a building or building components including, but not limited to, floors, ceilings, wall, windows, doors, stairs, bathrooms, furnishings, and exterior surfaces of office equipment, excluding the cleaning of work areas where manufacturing or repair activity is performed.

II.A.2.j. "Solvent Metal Cleaning" means the process of cleaning soils from metal surfaces by cold cleaning, conveyorized degreasing, or non-conveyorized vapor degreasing.

II.A.3. Transfer of waste solvent and used solvent

In any disposal or transfer of waste or used solvent, at least 80 percent by weight of the solvent/waste liquid shall be retained (i.e., no more than 20 percent of the liquid solvent/solute mixture shall evaporate or otherwise be lost during transfers).

II.A.4. Storage of waste solvent and used solvent

Waste or used solvent shall be stored in closed containers unless otherwise required by law.

II.A.5. Any control device shall meet the applicable requirements of Sections I.A.3.a., b., c., e., and I.A.8.a. and b.

II.B. Control of Solvent Cold-Cleaners

II.B.1. Control Equipment

II.B.1.a. Covers

II.B.1.a.(i) All cold-cleaners shall have a properly fitting cover.

II.B.1.a.(ii) Covers shall be designed to be easily operable with one hand under any of the following conditions:

II.B.1.a.(ii)(A) Solvent true vapor pressure is greater than 15 torr (0.3 psia) at 38°C (100°F).

II.B.1.a.(ii)(B) The solvent is agitated by an agitating mechanism.

II.B.1.a.(ii)(C) The solvent is heated.

II.B.1.b. Drainage Facility

II.B.1.b.(i) All cold-cleaners shall have a drainage facility that captures the drained liquid solvent from the cleaned parts.

II.B.1.b.(ii) For cold-cleaners using solvent which has a vapor pressure greater than 32 torr (0.62 psia) measured at 38°C (100°F) either:

II.B.1.b.(ii)(A) There shall be an internal drainage facility within the confines of the cold-cleaner, so that parts are enclosed under the (closed) cover to drain after cleaning, or if such a facility will not fit within;

II.B.1.b.(ii)(B) An enclosed, external drainage facility that captures the drained solvent liquid from the cleaned parts.

II.B.1.c. A permanent, clearly visible sign shall be mounted on or next to the cold-cleaner. The sign shall list the operating requirements.

II.B.1.d. Solvent spray apparatus shall not have a splashing, fine atomizing, or shower type action but rather should produce a solid, cohesive stream. Solvent spray shall be used at a pressure that does not cause excessive splashing.

For solvents with a true vapor pressure above 32 torr (0.62 psia) at 38°C (100°F), or, for solvents heated above 50°C (120°F), one of the following techniques shall be used:

II.B.1.d.(i) A freeboard ratio greater than or equal to 0.7.

II.B.1.d.(ii) A water or a non-volatile liquid cover. The cover liquid shall not be soluble in the solvent and shall not be denser than the solvent and the depth of the cover liquid shall be sufficient to prevent the escape of solvent vapors.

II.B.2. Operating requirements

II.B.2.a. The cold-cleaner cover shall be closed whenever parts are not being handled within the cleaner confines.

II.B.2.b. Cleaned parts shall be drained for at least 15 seconds and/or until dripping ceases. Any pools of solvent shall be tipped out on the clean part back into the tank.

II.C. Control of Non-Conveyorized Vapor Degreasers

II.C.1. Control Equipment

II.C.1.a. The non-conveyorized vapor degreaser shall have a cover which shall be designed and operated so that it can be easily opened and closed through the use of mechanical assists such as spring loading, counterweights, etc.; opening and closing the cover shall not disturb the vapor zone.

II.C.1.b. Safety Switches

The following two types of switches shall be installed on vapor degreasers:

II.C.1.b.(i) Condenser flow switch and thermostat - (shuts off sump heat if the condenser coolant is either not circulating or is too warm); and

II.C.1.b.(ii) Spray safety switch - (shuts off spray pump if the vapor level drops more than four (4) inches).

II.C.1.c. Control Device

II.C.1.c.(i) For non-conveyorized vapor degreasers with an open area (with the cover open) of one square meter (10.8 ft_2) or less, either the freeboard ratio shall be greater than or equal to 0.75, or one of the control devices in II.C.1.c.(ii) shall be used.

II.C.1.c.(ii) For non-conveyorized vapor degreasers with an open area (with the cover open) greater than one (1) square meter, (10.8 ft_2), at least one of the following control systems shall be used:

II.C.1.c.(ii)(A) Both a powered cover and a freeboard ratio greater than or equal to 0.75.

II.C.1.c.(ii)(B) A refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix C.

II.C.1.c.(ii)(C) An enclosed design: A system where the cover(s) or door(s) opens only when a dry part is entering or exiting the degreaser.

II.C.1.c.(ii)(D) A carbon adsorption system with ventilation greater than or equal to 15 cubic meters each minute per square meter (50 cfm/ft_2) of air/vapor area (when the cover(s) is [are] open), exhausting less than 25 parts per million (by volume) of solvent averaged over one complete adsorption cycle.

II.C.1.d. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.C.2. Operating Requirements

II.C.2.a. Keep cover closed at all times except when processing work loads into or out of the degreaser.

II.C.2.b. The following operations shall be performed to minimize solvent carry-out:

II.C.2.b.(i) Rack parts to allow full drainage.

II.C.2.b.(ii) Move parts as slowly as is practicable in and out of the degreaser. A maximum of one foot every five seconds by hand or a maximum of 5.5 cm/sec. (10.8ft/min) for a mechanically operated system.

II.C.2.b.(iii) Allow the workload to clean in the vapor zone at least 30 seconds or until condensation ceases.

II.C.2.b.(iv) Tip out any pools of solvent that remain on the cleaned parts before removal from the vapor zone.

II.C.2.b.(v) Allow parts to dry within the degreaser at least 15 seconds and/or until visually dry.

II.C.2.c. Solvents shall not be used to clean porous or absorbent materials; for example, cloth, leather, wood, rope, etc.

II.C.2.d. Workloads shall not occupy more than half of the degreaser's open top area.

II.C.2.e. Spraying shall not be done above the vapor level.

II.C.2.f. Solvent leaks shall be repaired immediately, or the degreaser shall be shut down.

II.C.2.g. Exhaust ventilation shall not exceed twenty (20) cubic meters per minute per square meter (65.6 cfm per sq. ft.) of degreaser open area, unless greater exhaust rates are necessary to meet Occupational and Safety Health Act requirements. Ventilation fans shall not be used near the degreaser opening, unless necessary to meet Occupational and Safety Health Act requirements.

II.C.2.h. The water separator shall function so that no visible water is present in the solvent exiting the separator.

II.D. Control of Conveyorized Degreasers

II.D.1. Control Equipment

II.D.1.a. Control Device

For all conveyorized degreasers with a solvent surface area greater than two (2) square meters (21.5 square feet), the degreasing shall be controlled by at least one of the following:

II.D.1.a.(i) Carbon adsorption system, with ventilation greater or equal to 15 cubic meters per minute per square meter (49.2 cfm/ft_2) of air/vapor interface for vapor degreasers (of air/liquid interface for non-vapor types) when down-time covers are open, and exhausting less than 25 parts per million of solvent (by volume) averaged over a complete adsorption cycle.

II.D.1.a.(ii) For vapor degreasers only: a refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix D.

II.D.1.b. Prevention of Carry-out

A drying tunnel, tumbling basket(s), or other demonstrably effective method(s) shall be employed to prevent cleaned parts from carrying out solvent liquid or vapor.

II.D.1.c. Safety Switches

II.D.1.c.(i) The following two (2) switch-circuits (or equivalent) shall be installed.

II.D.1.c.(i)(A) A spray safety switch shall shut off the spray pump and/or the conveyor if the vapor level drops more than four (4) inches.

II.D.1.c.(i)(B) A vapor level control thermostat shall shut off sump heat when the vapor level rises too high.

II.D.1.c.(ii) All conveyorized degreasers shall have a condenser thermostat and flow-detector switch (or equivalent) which shuts off sump heat if coolant is too warm or is not circulating.

II.D.1.d. Minimized Openings: Degreaser entrance and exit openings shall silhouette workloads so that the average clearance between parts (or parts-and the edge of the degreaser opening) is either:

II.D.1.d.(i) less than 10 centimeters (4 inches) or;

II.D.1.d.(ii) less than 10 percent of the width of the opening

II.D.1.e. Covers shall be provided to close off all the entrance(s) and exit(s) when the conveyor is not in use.

II.D.1.f. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.D.2. Operating Requirements

II.D.2.a. Exhaust ventilation shall not exceed 20 m^3/minute per square meter of degreaser opening (65.6 cf/m per square foot), unless necessary to meet OSHA requirements. Work place fans shall not be located near, nor directed at degreaser openings, unless necessary to meet OSHA requirements. Exhaust flow shall be measured by EPA reference methods 1 and 2 of 40 CFR Part 60 (September 14, 1989).

II.D.2.b. Carry-out emissions shall be minimized by:

II.D.2.b.(i) Racking parts in such a manner to achieve best drainage.

II.D.2.b.(ii) Maintaining the vertical component of conveyor speed at less than 3.3 meters per minute (10.8 feet per minute).

II.D.2.c. Repair solvent leaks immediately, or shut down the degreaser.

II.D.2.d. The water separator shall function with an efficiency sufficient to prevent water from being visible in the solvent exiting the separator.

II.D.2.e. Down-time cover(s) shall be placed over entrances and exits of conveyorized degreasers immediately after the conveyor and exhaust are shut down. Covers shall be retained in position until immediately before start-up.

II.E. Control of Industrial Cleaning Solvent Operations

II.E.1. Control Requirements

The owner or operator of an industrial cleaning solvent operation with total combined uncontrolled actual VOC emissions equal to or greater than three (3) tons per calendar year (excluding VOC emissions from solvents used for cleaning operations that are exempt under Section II.E.4.) must:

II.E.1.a. Limit the VOC content of cleaning solvents to less than or equal to 0.42 lb of VOC/gal (50 grams VOC/liter); or

II.E.1.b. Limit the composite partial vapor pressure of the cleaning solvent to 8 millimeters of mercury (mmHg) at 20 degrees Celsius (68 degrees Fahrenheit); or

II.E.1.c. Reduce VOC emissions with an emission control system having a control efficiency of 90% or greater.

II.E.2. Work Practice Requirements

The owner or operator of an industrial cleaning solvent operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.E.2.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.E.2.b. Properly dispose of used solvent and shop towels; and

II.E.2.c. Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintaining cleaning equipment to be leak free.

II.E.3. Monitoring, Recordkeeping and Reporting Requirements

II.E.3.a. The owner or operator of an industrial cleaning solvent operation must keep the following records for two (2) years and make them available for inspection by the Division upon request:

II.E.3.a.(i) If applicable, records demonstrating that a listed exemption to this Section II.E. applies.

II.E.3.a.(ii) If applicable, monthly records such as safety data sheets or other analytical data from the industrial cleaning solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent cleaning operations to demonstrate compliance with the control requirements in Sections II.E.1.a. and II.E.1.b.

II.E.3.a.(iii) If applicable, monthly records sufficient to demonstrate compliance with the control requirement in Section II.E.1.c.

II.E.3.a.(iv) Records of calendar year VOC emission estimates demonstrating whether the industrial cleaning solvent operation meets or exceeds the applicability threshold in Section II.E.1.

II.E.3.b. Compliance with the control requirements in Section II.E.1. must be demonstrated using one of the following methods as applicable:

II.E.3.b.(i) Safety data sheets or other analytical data from the industrial cleaning solvent manufacturer to demonstrate compliance with Sections II.E.1.a. and II.E.1.b.;

II.E.3.b.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with Section II.E.1.c.; or

II.E.3.b.(iii) A performance test conducted during representative operations using one of the following methods, as applicable:

II.E.3.b.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content;

II.E.3.b.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.E.4. Exemptions

II.E.4.a. Industrial cleaning solvent operations are not subject to Section II.E. if they are subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT.

II.E.4.b. The VOC control requirements in Section II.E.1. do not apply to:

II.E.4.b.(i) Cleaning of electrical and electronic components;

II.E.4.b.(ii) Cleaning of precision optics;

II.E.4.b.(iii) Cleaning of numismatic dies;

II.E.4.b.(iv) Stripping of cured inks, coatings, and adhesives;

II.E.4.b.(v) Cleaning of resin, coating, ink, and adhesive manufacturing, mixing, molding, and application equipment;

II.E.4.b.(vi) Cleaning of research and development laboratories;

II.E.4.b.(vii) Cleaning of medical device or pharmaceutical manufacturing equipment;

II.E.4.b.(viii) Performance testing to determine coating, adhesive, ink or ink performance;

II.E.4.b.(ix) Cleaning of equipment and materials used in testing for quality control or quality assurance purposes;

II.E.4.b.(x) Cleaning of digital printing operations; and

II.E.4.b.(xi) Cleaning of screen printing operations.

II.E.4.c. In lieu of compliance with Section II.E.1. and II.E.2., the owner or operator of an area source aerospace facility, as defined in 40 CFR Part 63, Section 63.742

(November 17, 2016), may implement the solvent cleaning provisions of the National Emission Standards for Hazardous Air Pollutants for Aerospace Manufacturing and Rework facilities contained in 40 CFR Part 63, Section 63.744 (November 17, 2016) along with the applicable definitions contained in 40 CFR Part 63, Section 63.742 (November 17, 2016), except that:

II.E.4.c.(i) VOC-containing solvents which meet the definition of “non-HAP materials” in 40 CFR Part 63, Section 63.742 (November 17, 2016) are not excluded from the housekeeping measures contained in 40 CFR Part 63, Section 63.744(a) (November 17, 2016); and

II.E.4.c.(ii) The baseline reduction compliance option contained in 40 CFR Part 63, Section 63.744(b)(3) (November 17, 2016) is not available for purposes of compliance with this VOC control rule.

II.F. General Solvent Use

II.F.1. Applicability

II.F.1.a. Within the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to two (2) tons per year that existed at major sources of VOC (greater than or equal to 50 tpy VOC) as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.1.b. (State Only) Outside the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to five (5) tons per year that existed at sources of VOC greater than or equal to 50 tpy VOC as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.2. Exemptions

The requirements of this Section II.F. do not apply to:

II.F.2.a. Operations that are subject to a solvent work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that constitutes RACT, or;

II.F.2.b. Solvent use where the solvent does not contain VOCs.

II.F.3. Work practice requirements

The owner or operator of operations that use solvents must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.F.3.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.F.3.b. Properly dispose of used solvent and solvent contaminated waste (e.g. shop towels and carbon filtration or other control device media), and;

II.F.3.c. Implement good air pollution control practices that minimize emissions, including but not limited to:

II.F.3.c.(i) Using low or no-VOC solvents, if possible;

II.F.3.c.(ii) Using only volumes of solvent necessary for operations;

II.F.3.c.(iii) Using submerged fill pipes in storage tanks and containers;

II.F.3.c.(iv) Using closed loop systems to minimize solvent loss during transfer and use of solvents;

II.F.3.c.(v) Maintaining solvent storage, transfer, and use operations equipment in such a way that it minimizes evaporation loss and remains leak free, and;

II.F.3.c.(vi) Owners or operators of sources that use a carbon adsorption system must provide for the proper disposal or reuse of all VOC recovered.

II.F.4. Control of general solvent use

The owner or operator of operations that use solvents with uncontrolled actual VOC emissions greater than or equal to twenty-five (25) tons per year on a calendar year basis, and that are located in the 8-Hour Ozone Control Area, must reduce solvent use VOC emissions by 90%.

II.F.5. Monitoring requirements

II.F.5.a. The owner or operator of operations that use solvents that utilize a closed-loop system for emission control must inspect the control system using audio, visual, olfactory (AVO) on a monthly basis for perceptible emissions. First attempt to repair must be made upon detection if feasible, but no later than three (3) calendar days from detection.

II.F.5.b The owner or operator of operations that use solvents that utilize a control device must operate and maintain the control device consistent with the manufacturer's specifications.

II.F.5.c. The owner or operator of operations that use solvents that are subject to the 90% control requirement in Section II.F.4. must:

II.F.5.c.(i) Complete a performance test once every three (3) years during representative operations to verify compliance with Section II.F.4. using one of the following methods, as applicable:

II.F.5.c.(i)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content.

II.F.5.c.(i)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.F.5.c.(ii) Conduct all performance tests in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

II.F.5.c.(iii) Comply with control device and monitoring system manufacturers' specifications for operation and maintenance for equipment used to demonstrate compliance with Section II.F.4.

II.F.6. Recordkeeping

II.F.6.a. Records of calendar year VOC emission estimates demonstrating whether the solvent operation meets or exceeds the applicability threshold in Section II.F.1.

II.F.6.b. If applicable, records demonstrating that an exemption to Section II.F.2. applies.

II.F.6.c. Monthly solvent losses based on beginning and ending inventories, solvent received, inventory adjustments, solvent destroyed in a control device, solvent recovered, and any volume of solvent normally retained in recovery equipment. Solvent losses must be totaled on a rolling 12-month basis.

II.F.6.d. Monthly records such as safety data sheets or other analytical data from the solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent operations.

II.F.6.e. Records of negative pressure ranges, and other records necessary to demonstrate compliance with Section II.F.3.

II.F.6.f. Manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section II.F.4.

II.F.6.g. If applicable, monthly records of operation and maintenance of control device and monitoring system according to manufacturer's specifications to demonstrate compliance with Sections II.F.4. and II.F.5.

II.F.6.h. If applicable, Records of performance tests conducted to demonstrate compliance with Section II.F.5.

II.F.6.i. If applicable, monthly records of AVO inspections including:

II.F.6.i.(i) The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.F.6.i.(ii) A list of the leaks requiring repair,

II.F.6.i.(iii) The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

II.F.6.i.(iv) The date the leak was repaired and type of repair method applied.

II.F.6.j. Records must be maintained for two (2) years and made available for inspection by the Division upon request.

III. Use of Cutback Asphalt

III.A. Definitions

III.A.1. “Asphalt or Asphalt Cement” The dark-brown to black cementitious material (solid, semi-solid, or liquid in consistency) of which the main constituents are bitumen’s which occur naturally or as a residue of petroleum refining.

III.A.2. “Asphalt Concrete” A waterproof and durable paving material composed of dried aggregate, which is evenly coated with hot asphalt cement.

III.A.3. “Cutback Asphalt or Cutback Asphalt Cement” Any asphalt which has been liquefied by blending with a VOC, such as a petroleum solvent diluents or, in the case of some slow cure asphalts (Road Oils), which has been produced directly from the distillation of petroleum.

III.A.4. “Emulsified Asphalt” Asphalt emulsions produced by combining asphalt and water with emulsifying agent. Emulsified Asphalt or any other coating or sealant, including but not limited to those produced from petroleum or coal, which contain more than five (5) percent of oil distillate as determined by ASTM Method D-244 is included in this definition.

III.A.5. “Penetrating Prime Coat” An application of low-viscosity liquid asphalt to an absorbent surface in order to prepare it for overlaying with a layer or layers of asphalt cement or asphalt emulsion and mineral aggregate paving materials.

III.B. Limitations

III.B.1. Applicability

The provisions of this Section III. apply to the use and storage of cutback asphalt for the paving and maintenance of all public roadways (including alleys), private roadways, parking lots, and driveways only within ozone nonattainment areas.

III.B.2. Storage

Stockpiles of aggregate mixed with cutback asphalt are permitted October 1 through February 28 (29). Such storage is not permitted March 1 through September 30 except where it can be demonstrated to the Division that such storage is necessary.

III.B.3. Use

Cutback asphalt may be used for any paving purpose October 1 through February 28 (29). No person shall use cutback asphalt or any coating included in the definition of cutback asphalt in Section III.A.3. March 1 through September 30 except as provided:

III.B.3.a. If used solely as a penetrating prime coat, or

III.B.3.b. If the user can demonstrate to the Division that under the conditions of its intended use, there will be no emissions of volatile organic compounds to the ambient air.

III.C. Recordkeeping

During the months of March through September, the person responsible for the use or storage of any cutback asphalt as permitted in Sections III.B.3.a., III.B.3.b., and Section III.B.2. shall keep records of same, including type and amount of solvent(s) used.

IV. Graphic Arts and Printing

IV.A. Packaging Rotogravure, Publication Rotogravure, and Flexographic Printing

IV.A.1. Definitions

For the purpose of this section, the following definitions apply:

IV.A.1.a. "Flexographic Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique in which the pattern to be applied is raised above the printing roll and the image carrier is made of rubber or other elastomeric materials.

IV.A.1.b. "Packaging Rotogravure Printing" means rotogravure printing upon paper, paperboard, metal foil, plastic film, and other substrates, which are, in subsequent operations, formed into packaging products and labels for articles to be sold.

IV.A.1.c. "Publication Rotogravure Printing" means rotogravure printing upon paper, which is subsequently formed into books, magazines, catalogues, brochures, directories, newspaper supplements, and other types of printed materials.

IV.A.1.d. "Roll Printing" means the application of words, designs, and pictures to a substrate usually by means of a series of hard rubber or steel rolls each with only partial coverage.

IV.A.1.e. "Rotogravure Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique, which involves an intaglio or recessed image areas in the form of cells.

IV.A.2. Applicability

IV.A.2.a. This section applies to all packaging rotogravure, publication rotogravure, and flexographic printing facilities whose potential emissions of volatile organic compounds before control (determined at design capacity and 8760 hrs/year, or at maximum production, and accounting for any capacity or production limitations in a federally-enforceable permit) are equal to or more than 90,000 Kg per year (100 tons/year). Potential emissions are to be estimated by extrapolating historical records of actual consumption of solvent and ink. (e.g., the historical use of 20 gallons of ink for 4,000 annual hours would be extrapolated to 43.8 gallons for 8760 hours.) The before-control volatile organic compound emissions calculations shall be the summation of all volatile organic compounds in the inks and solvents (including cleaning liquids) used.

IV.A.3. Provisions for Specific Processes

IV.A.3.a. No owner or operator of a facility subject to this section and employing VOC-containing ink shall operate, cause, allow, or permit the operation of the facility unless:

IV.A.3.a.(i) The volatile fraction of ink, as it is applied to the substrate, contains 25.0 percent or less (by volume) of VOC and 75.0 percent or more (by volume) of water; or

IV.A.3.a.(ii) The ink (minus water) as it is applied to the substrate, contains 60.0 percent or more (by volume) non-volatile material; or

IV.A.3.a.(iii) The owner or operator installs and operates a control device and capture system in accordance with Sections IV.A.3.b. and IV.A.3.c.; or

IV.A.3.a.(iv) A combination of solvent-borne inks and low solvent inks that achieve a 70% (volume) overall reduction of solvent usage (compared to an all solvent borne ink usage) is used; or

IV.A.3.a.(v) Flexographic and packaging rotogravure printing facilities limit emissions to 0.5 pounds of VOC per pound of solids in the ink. The limit includes all solvent added to the ink: solvent in the purchased ink, solvent added to cut the ink to achieve desired press viscosity, and solvent added to ink on the press to maintain viscosity during the press run. (Publication rotogravure facilities shall not use this option); or

IV.A.3.a.(vi) Crossline averaging is used. The requirements of Section I.A.5.d. apply.

IV.A.3.b. A capture system shall be used in conjunction with the emission control system in Section IV.A.3.a. The design and operation of a capture system shall be consistent with good engineering practice, and in conjunction with control equipment shall be required to provide for an overall reduction in volatile organic compound emissions of at least:

IV.A.3.b.(i) 75.0 percent where a publication rotogravure process is employed;

IV.A.3.b.(ii) 65.0 percent where a packaging rotogravure process is employed; or

IV.A.3.b.(iii) 60.0 percent where a flexographic printing process is employed.

IV.A.3.c. The design, operation, and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Testing of any capture system may be required by the Division on a case-by-case basis, in cases where a total enclosure is not used or when material balance results are questionable. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

IV.A.3.d. The overall reduction in VOC emissions specified in Section IV.A.3.b. shall be calculated by material balance methods approved by the Division, or by determination of capture and control device efficiencies. The overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

IV.A.4. Testing and Monitoring

The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Part C, Sections I.A.3., I.A.7, I.A.9., and I.A.10. In Part C, Section I.A.3., EPA reference method 24A shall be the test method used for publication rotogravure inks, while EPA Reference method 24 data is acceptable for all other inks. Test methods as set forth in Appendix A, Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR), in effect July 1, 1993.

IV.A.5. The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Section I.A.8. "A Guideline for Graphic Arts Calculations" shall be used for compliance determination.

IV.B. Lithographic and Letterpress Printing

IV.B.1. General Provisions

IV.B.1.a. Definitions

IV.B.1.a.(i) “Alcohol” means any of the hydroxyl-containing organic compounds with a molecular weight equal to or less than 74.12, which includes methanol, ethanol, propanol, and butanol.

IV.B.1.a.(ii) “Alcohol substitute” means nonalcohol additives that contain VOCs and are used in the fountain solution to reduce the surface tension of water or prevent ink piling.

IV.B.1.a.(iii) “Cleaning material” means a VOC-containing material used to remove ink and debris from the printing press area, operating surfaces of the printing press and, printing press parts. Blanket wash is a type of cleaning material.

IV.B.1.a.(iv) “Composite partial vapor pressure” means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the “i”th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the “i”th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the “i”th VOC compound at 20°C(68°F), in mm Hg

IV.B.1.a.(v) “Fountain solution” means a mixture of water, nonvolatile printing chemicals, and a liquid additive that reduces the surface tension of the water so that it spreads easily across the printing plate surface. The fountain solution wets the non-image areas so that the ink is maintained within the image areas.

IV.B.1.a.(vi “Heatset” means any lithographic or letterpress printing operation where printing inks are set by the evaporation of the ink oils in a heatset dryer.

IV.B.1.a.(vii) “Heatset dryer” means a hot air dryer used in heatset lithography to heat the printed substrate and to promote the evaporation of ink oils.

IV.B.1.a.(viii) “Lithographic printing” means a planographic printing process where the image and non-image areas are chemically differentiated (the image area is oil receptive and the non-image area is water receptive). This printing process differs from other conventional printing methods, where the image is a raised or recessed surface.

IV.B.1.a.(ix) “Letterpress printing” means a printing process in which the image area is raised relative to the non-image area and the paste ink is transferred to the substrate directly from the image surface.

IV.B.1.a.(x) “Non-heatset” means any printing operation where the printing inks are set without the use of heat. For the purpose of Section IV.B., ultraviolet-cured and electron beam-cured inks are considered non-heatset.

IV.B.1.a.(xi) “Offset lithographic printing” means a printing process that transfers the ink film from the lithographic plate to an intermediary surface (blanket), which in turn transfers the ink film to the substrate.

IV.B.1.a.(xii) “Press” means a printing production assembly composed of one or more print units used to produce a printed substrate including any associated coating, spray powder application, heatset web dryer, ultraviolet or electron beam curing units, or infrared heating units.

IV.B.1.a.(xiii) “Sheet-fed printing” means a printing process where individual sheets of paper or substrate are fed into the printing press.

IV.B.1.a.(xiv) “Web printing” means a printing process where continuous rolls of substrate material are fed to the press and rewound or cut to size after printing.

IV.B.1.b. Applicability

IV.B.1.b.(i) The provisions of this Section IV.B. apply to fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses. These materials are not subject to the requirements of Sections I. and II.

IV.B.1.b.(ii) The work practice requirements in Section IV.B.1.c. apply to all lithographic and letterpress printing operations.

IV.B.1.b.(iii) The VOC content limit for inks in Section IV.B.1.d. applies to lithographic and letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(iv) The cleaning material requirements in Section IV.B.2. apply to letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(v) The cleaning material and fountain solution requirements in Sections IV.B.2. and IV.B.3. apply to offset lithographic printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(vi) The control requirements in Section IV.B.4. apply to each heatset web offset lithographic and heatset web letterpress printing press with the potential to emit from the dryer, prior to controls, at least 25 tons per calendar year of VOC (petroleum ink oil) from heatset inks.

IV.B.1.c. Work Practice Requirements

Lithographic and letterpress printing operations must implement the following work practices at all times to reduce VOC emissions from fugitive sources:

IV.B.1.c.(i) Cover open containers and keep cleaning materials in closed containers when not in use;

IV.B.1.c.(ii) Properly dispose of used cleaning materials, fountain solutions, and used shop towels; and

IV.B.1.c.(iii) Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintain cleaning equipment to repair cleaning materials leaks.

IV.B.1.d. VOC Content Limit for Inks

IV.B.1.d.(i) Lithographic and letterpress printing operations, excluding heatset web offset and heatset web letterpress printing operations, must use low-VOC inks, which average less than 30% (by weight) VOC on a monthly basis.

IV.B.1.d.(ii) Heatset web offset lithographic and heatset web letterpress printing operations must use low-VOC inks, which average less than 40% (by weight) VOC on a monthly basis.

IV.B.2. Offset lithographic printing and letterpress printing operations must comply with the following cleaning materials requirements;

IV.B.2.a. All cleaning materials must contain less than 70% (by weight) VOC or have a VOC composite vapor pressure less than 10 mmHg at 20°C.

IV.B.2.b. Exemptions

The following materials and operations are exempt from the cleaning material requirements in Section IV.B.2.a.:

IV.B.2.b.(i) Cleaners used on electronic components of a press.

IV.B.2.b.(ii) Pre-press cleaning operations.

IV.B.2.b.(iii) Post-press cleaning operations.

IV.B.2.b.(iv) Floor cleaning supplies (other than those used to clean dried ink).

IV.B.2.b.(v) Cleaning performed in parts washers or cold cleaners that are subject to Section II.

IV.B.2.c. Use of non-compliant cleaning materials

Cleaning materials not meeting the limits in Section IV.B.2.a. are limited to less than or equal to 110 gallons per calendar year.

IV.B.3. Offset lithographic printing operations must comply with the following fountain solution requirements:

IV.B.3.a. Heatset web offset lithographic printing operations must:

IV.B.3.a.(i) Use a fountain solution containing 1.6% alcohol (by weight) or less as applied;

IV.B.3.a.(ii) Use a fountain solution containing 3% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

IV.B.3.a.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b. Sheet-fed printing operations must

IV.B.3.b.(i) Use a fountain solution containing 5% alcohol (by weight) or less as applied;

IV.B.3.b.(ii) Use a fountain solution containing 8.5% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

IV.B.3.b.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b.(iv) The following are exempt from the fountain solution requirements in Section IV.B.3.b.:

IV.B.3.b.(iv)(A) Fountain solution use associated with a sheet-fed printing press with maximum sheet size 11x17 inches or smaller.

IV.B.3.b.(iv)(B) Fountain solution use associated with a sheet-fed printing press having a total fountain solution reservoir less than one (1) gallon.

IV.B.3.c. Non-heatset web printing must use a fountain solution containing 5% alcohol substitute (by weight) or less and no alcohol.

IV.B.4. Heatset web offset lithographic and heatset web letterpress printing operations must comply with the following control requirements:

IV.B.4.a. Heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 90% or greater.

IV.B.4.b. If the control device was first installed on or after January 1, 2017, heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 95% or greater.

IV.B.4.c. Where inlet VOC concentration is low and a 90 or 95% control efficiency is not achievable due to low inlet concentrations or measurable due to equipment configuration, heatset web offset lithographic and heatset web letterpress printing operations may reduce the control device outlet concentration to 20 ppmv (as hexane on a dry basis).

IV.B.4.d. The following are exempt from the control requirements in Section IV.B.4.:

IV.B.4.d.(i) Heatset presses used for book printing.

IV.B.4.d.(ii) Heatset presses with maximum web width of 22 inches or less.

IV.B.4.d.(iii) Waterborne or radiation (ultra-violet or electron beam) cured materials that are not heatset.

IV.B.5. Monitoring, Recordkeeping and Reporting

IV.B.5.a. The owner or operator of a heatset web offset lithographic or heatset web letterpress printing operation required to demonstrate compliance with Section IV.B.4. must install, calibrate, maintain, and operate a temperature monitoring device, according to the manufacturer's specifications.

IV.B.5.b. The owner or operator of a lithographic and letterpress printing operations subject to Sections IV.B.1.d. and IV.B.2. through IV.B.4. must keep the following records for two (2) years and make them available for inspection by the Division upon request:

IV.B.5.b.(i) If applicable, records demonstrating that a listed exemption to this Section IV.B. applies.

IV.B.5.b.(ii) If applicable, monthly records of the type, alcohol content or alcohol substitute content, and total volume of fountain solution used in printing operations.

IV.B.5.b.(iii) If applicable, monthly records of the type, VOC content or composite vapor pressure, and total volume of the cleaning materials used in printing operations.

IV.B.5.b.(iv) If applicable, monthly records of the type, VOC content, and total volume of inks (including varnishes) and coatings used in printing operations.

IV.B.5.b.(v) If applicable, monthly records demonstrating compliance with the control requirements in Section IV.B.4.

IV.B.5.b.(vi) Records of calendar year VOC emission estimates demonstrating whether the printing operation meets or exceed the applicability thresholds in Section IV.B.1.b.

IV.B.5.c. Compliance with control requirements must be demonstrated using the following methods as applicable:

IV.B.5.c.(i) Safety data sheets or other analytical data from the ink, cleaning material, or fountain solution manufacturer to demonstrate compliance with VOC content limit for inks in Section IV.B.1.d., the cleaning material requirements in Section IV.B.2., and the fountain solution requirements in Section IV.B.3.;

IV.B.5.c.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with the control equipment requirements in Section IV.B.4.; or

IV.B.5.c.(iii) A performance test conducted during representative conditions using one of the following methods as applicable:

IV.B.5.c.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content for inks, fountain solutions and cleaning materials; or

IV.B.5.c.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency or outlet concentration of the emission control equipment.

V. Pharmaceutical Synthesis

V.A. General Provisions

V.A.1. Applicability

This section applies to all sources of volatile organic compounds associated with pharmaceutical manufacturing activities, including, but not limited to, reactors, distillation units, dryers, storage of VOCs, extraction equipment, filters, crystallizers, and centrifuges.

V.A.2. Exemptions

Extraction of organic substances from animal or vegetable material; fermentation and culturing; formulation and packaging of pharmaceutical or medicinal products.

V.A.3. Definitions

For the purpose of this section, the following definitions apply:

V.A.3.a. "Control System" means any number of control devices, including condensers, which are designed and operated to reduce the quantity of VOC emitted to the atmosphere.

V.A.3.b. "Pharmaceutical" means a medicine or drug which appears in the United States Pharmacopoeia National Formulary, or which is so designated by the National Drug Code of the United States FDA Bureau of Drugs.

V.A.3.c. "Production Equipment Exhaust System" means a device for collecting and directing out of the work area VOC fugitive emissions from reactor openings, centrifuge openings, and other vessel openings for the purpose of protecting workers from excessive VOC exposure.

V.A.3.d. "Reactor" means a vat or vessel, which may be jacketed to permit temperature control, designed to contain chemical reactions.

V.A.3.e. "Separation Operation" means a process that separates a mixture of compounds and solvents into two or more components. Specific mechanisms include, but are not limited to, extraction, centrifugation, filtration, distillation, and crystallization.

V.A.3.f. "Synthesized Pharmaceutical Manufacturing" means manufacture of pharmaceutical products by chemical synthesis. It includes the manufacture of chemical intermediates (of sufficient purity) which are typically used by the pharmaceutical industry as precursors to finished mixtures of chemicals. (Thus, it excludes those chemical processes which are not directed at creating finished pharmaceutical or chemical intermediates to finished pharmaceuticals.)

V.B. Provisions for Specific Processes

V.B.1. The owner or operator of a facility subject to this section shall control the volatile organic compound emissions from each vent which has the potential to emit 6.80 kg/day (l5 lb./day) or more of VOC from reactors, distillation operations, crystallizers, centrifuge and vacuum dryers. Surface condensers or equivalent controls shall be used, provided that, if surface condensers are used, the condenser outlet gas temperature shall not exceed the following values:

VOCs True Vapor Pressure* at 20° in torr (and psia) from (minimum) up to ** (maximum)	Maximum temperature of Gas Stream immediately exiting the condenser
0-26(0-0.5)	35°C (95°F)
26-52(0.5-1.0)	25°C(77°F)
52-78(1.0-1.5)	10°C(50°F)
78-150(1.5-2.9)	0°C(32°F)
150-300(2.9-5.8)	-15°C(5°F)
Greater than 300(Greater than 5.8)	-25°C(-13°F)

*The calculation methods for gases containing more than one condensable component are complex. As a simplification, the temperature necessary for control by condensation can be roughly approximated by the weighted average of the temperatures necessary for condensation of each VOC considered separately but at concentrations equal to the total organic concentration.

**But not including the maximum value of the range.

V.B.2. Division approval shall be required for control equipment used to control VOCs of 570 torr (11 psia) and above.

V.B.3. The owner or operator of a facility subject to this section shall reduce the VOC emissions from each air dryer and production equipment exhaust system:

V.B.3.a. By at least 90 percent if emissions are 150 kg/day (330 lbs/day) or more of VOC, or,

V.B.3.b. To 15.0 kg/day (33 lb/day) or less if emissions are less than 150 kg/day (330 lb/day) of VOC.

V.B.4. The owner or operator of a facility subject to this section shall:

V.B.4.a. Provide a vapor balance system or equivalent control that is at least 90.0 percent effective in reducing emissions from truck or railcar deliveries to storage tanks with capacities greater than 7,570 liters (2,000 gallons) that store VOC with true vapor pressure greater than 210 torr (4.1 psia) at 20°C; and,

V.B.4.b. Install pressure/vacuum conservation vents set at plus or minus 0.2 kPa on all storage tanks that store VOC with true vapor pressures greater than 10.0 kPa (1.5 psi) at 20°C.

V.B.5. The owner or operator of a facility subject to this section shall enclose all centrifuges, rotary vacuum filters, and other filters having an exposed liquid surface, where the liquid contains VOC and exerts a total VOC true vapor pressure of 26 torr (0.5 psia) or more at 20°C.

V.B.6. The owner or operator of a synthesized pharmaceutical facility subject to this section shall install covers on all in-process tanks containing a volatile organic compound at any time. These covers shall remain closed unless sampling, maintenance, short-duration production procedures or inspection procedures require access.

V.B.7. The owner or operator of a facility subject to this section shall repair all leaks from which a liquid, containing VOC, can be observed running or dripping. The repair shall be completed the first time the equipment is off-line for a period of time long enough to complete the repair, except that no leak shall go unrepaired for more than 14 days after initial detection unless the Division issues written approval.

V.B.8. Each surface condenser shall have at least one temperature indicator with its sensor located in the outlet gas stream.

V.C. Testing and Monitoring

V.C.1. Sources subject to the requirements of this section are also subject to the requirements of Sections I.A.3., I.A.7., I.A.8., and I.A.9.

Appendix D Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers

The specifications in this Appendix apply only to vapor degreasers that have both condenser coils and refrigerated freeboard chillers. (The coolant in the condenser coils is normally water.) The amount of refrigeration capacity is expressed in Calories/Hour per meter of perimeter. This perimeter is measured at the air/vapor interface.

For refrigerated chillers operated below 0°C., the following requirements apply:

DEGREASER WIDTH	*CALORIES/HR METER OF PERIMETER	BTU/HR FOOT OF PERIMETER
Less than 1.1 meters (3.5 ft.)	165	200
1.1 - 1.8 meters (3.5 - 6.0 ft.)	250	300
1.8 - 2.4 meters (6.0 - 8.0 ft.)	335	400
2.4 - 3.0 meters (8.0 - 10.0 ft.)	145	500
Greater than 3.0 meters (10 ft.)	500	600

* Kilocalories (1 Kilocalorie = 4184.0 joules)

For refrigerated chillers operating above 0°C., there shall be at least 415 Calories/Hr. - meter of perimeter (500 BTU/Hr-ft.), regardless of size.

Definition: "Air/Vapor Interface" - means the surface defined by the top of the solvent vapor layer within the confines of a vapor degreaser.

Appendix E Emission Limit Conversion Procedure

The following procedure shall be used to convert emission limits expressed as lb VOC/gallon coating less water and exempt solvents to limits expressed as lb VOC/gallon solids. This example uses the emission limit of 3.7 lb VOC/gallon coating.

Assume VOC density of the `Presumptive' RACT coating is 7.36 pounds per gallon because this same value was used to determine the "Presumptive" recommended RACT emission limits from volume solids data.

(3.7) LB VOC / GAL COATING LESS WATER x I GAL VOC x 100 / 7.36 LB VOC = (50) V0L% VOC
100 - (50) V0L% VOC = (50) V0L% SOLIDS
(3.7) LB VOC / GAL COATING LESS H2O x 100 GAL COATING / (50) GAL SOLIDS = (7.4) LB VOC / GAL SOLIDS

See "A Guideline for Surface Coating Calculations" EPA - 340/1-86-0l6 for additional examples.

The following table lists equivalent mass VOC/volume solids emission limits for various coating operations.

Equivalency Data for Surface Coating Processes (VOC Density = 7.36 lb/gal)

Industrial Finishing Categories	Lb VOC per Gallon Coating less water	Lb VOC per Gallon of Solids	Kg VOC per Liter of Solids
Can Industry			
Sheet Basecoat (Exterior and Interior) and over-varnish; two-piece can exterior (base-coat and over-varnish)	2.8	4.5	0.55
Two- and three-piece can interior body spray, two-piece can exterior end spray or roll coat	4.2	9.8	1.19
Three-piece can side-seam spray	5.5	21.7	2.61
End sealing compound	3.7	7.4	0.88
Any additional coats	4.2	9.8	1.19
Coil Coating			
Any coat	2.6	4.0	0.48

Fabric Coating			
Fabric coating line	2.9	4.8	0.58
Vinyl coating line	3.8	7.9	0.93
Paper Coating			
Coating line	2.9	4.8	0.58
Automotive and Light-Duty Truck Assembly Plant			
Primer (electrodeposition) application, flashoff area and oven	1.9	2.6	0.31
Topcoat application, flashoff area and oven	2.8	4.5	0.55
Final repair application, flashoff area and oven	4.8	13.8	1.67
Metal Furniture			
Coating line	3.0	5.1	0.61
Magnet Wire			
Wire coating operation	1.7	2.2	0.26
Large Appliances			
Prime, single, or topcoat application area, flashoff area and oven	2.8	4.5	0.55
Miscellaneous Metal Parts and Products			
Air-dried items	3.5	6.7	0.80
Clear-coated items	4.3	10.3	1.25
Extreme performance coatings	3.5	6.7	0.80
Other coatings and systems	3.0	5.1	0.61
Plastic Film Coating			
Plastic film coating line	2.9	4.8	0.58

PART D Oil and Natural Gas Operations

I. Volatile Organic Compound Emissions from Oil and Gas Operations

I.A. Applicability

I.A.1. Except as provided in Section I.A.2., this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in the 8-hour Ozone Control Area (State Only: or any ozone nonattainment or attainment/maintenance area) and that are located at or upstream of a natural gas plant.

I.A.2. Oil refineries are not subject to Section I.

I.B. Definitions specific to Section I.

I.B.1. “Affected Operations” means oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations, to which Section I. applies.

I.B.2. “Air Pollution Control Equipment”, as used in Section I., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment, pollution prevention devices, and processes that comply with the requirements of Section I.D.4. that are approved by the Division.

I.B.3. “Approved Instrument Monitoring Method” means an infra-red camera, EPA Method 21, or other instrument based monitoring method or program approved in accordance with Section I.L.8. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection, recordkeeping, and reporting program for such operations.

I.B.4. “Atmospheric Storage Tanks or Atmospheric Condensate Storage Tanks” means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.

I.B.5. “Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

I.B.6. “Calendar Week” means a week beginning with Sunday and ending with Saturday.

I.B.7. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

I.B.8. “Condensate Storage Tank” means any tank or series of tanks that store condensate and are either manifolded together or are located at the same well pad.

I.B.9. “Centrifugal Compressor” means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

I.B.10. “Component” means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

I.B.11. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

I.B.12. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

I.B.13. "Downtime" means the period of time when a well is producing and the air pollution control equipment is not in operation.

I.B.14. "Existing" means any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.

I.B.15. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

I.B.16. "Hydrocarbon liquids" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquids does not include produced water.

I.B.17. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

I.B.18. "Modified or Modification" means any physical change or change in operation of a stationary source that results in an increase in actual uncontrolled volatile organic compound emissions from the previous calendar year that occurs on or after February 1, 2009. For atmospheric condensate storage tanks (and beginning March 1, 2020, for all storage tanks), a physical change or change in operation includes but is not limited to drilling wells and recompleting, refracturing or otherwise stimulating existing wells.

I.B.19. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

I.B.20. "Natural Gas-Driven Diaphragm Pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

I.B.21. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

I.B.22. "New" means any atmospheric condensate storage tank that began operation on or after February 1, 2009.

I.B.23. “Produced Water” means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

I.B.24. “Reciprocating Compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

I.B.25. “Stabilized” when used to refer to stored hydrocarbon liquids, means that the hydrocarbon liquids have reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as “working and breathing losses”.

I.B.26. “Storage tank” means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

I.B.27. “Storage vessel” means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

I.B.28. (State Only) “Surveillance System” means monitoring pilot flame presence or temperature in a combustion device either by visual observation or with an electronic device to record times and duration of periods where a pilot flame is not detected at least once per day.

I.B.29. “System-Wide Control Strategy” means the collective emissions and emission reductions from all atmospheric condensate storage tanks under common ownership within the 8-hour Ozone Control Area for which uncontrolled actual volatile organic compound emissions are equal to or greater than two tons per year.

I.B.30. “Well Production Facility” means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

I.C. General Provisions

I.C.1. General Requirements

I.C.1.a. All air pollution control equipment used to demonstrate compliance with this Section I. must be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates required by this Section I. and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

I.C.1.b. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable.

I.C.1.c. All air pollution control equipment used to demonstrate compliance with Sections I.D., I.J., and I.K. must meet a control efficiency of at least 95%. Failure to properly install, operate, and maintain air pollution control equipment is a violation of this regulation.

I.C.1.d. If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly.

I.C.1.e. All combustion devices used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. must be equipped with and operate an auto-igniter as follows:

I.C.1.e.(i) (State Only) For condensate storage tanks that are constructed or modified after May 1, 2009, and before January 1, 2017, and controlled by a combustion device, auto-igniters must be installed and operational, beginning the date of first production after any new tank installation or tank modification.

I.C.1.e.(ii) (State Only) For all existing condensate storage tanks controlled by a combustion device in order to comply with the emissions control requirements of Section I.D.1., auto-igniters must be installed and operational beginning May 1, 2009, for condensate storage tanks with actual uncontrolled emissions of greater than or equal to 50 tons per year, and beginning May 1, 2010, for all other existing condensate storage tanks controlled by a combustion device, or within 180 days from first having installed the combustion device, whichever date comes later.

I.C.1.e.(iii) All combustion devices installed on or after January 1, 2017, must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.e.(iv) All combustion devices installed on or after January 1, 2018, and used to comply with Sections I.J. or I.K. must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.f. (State Only) If a combustion device is used to control emissions of volatile organic compounds, surveillance systems must be employed and operational as follows:

I.C.1.f.(i) (State Only) Beginning May 1, 2010, for all existing condensate storage tanks with uncontrolled actual emissions of 100 tons per year or more based on data from the previous twelve consecutive months.

I.C.1.f.(ii) (State Only) For all new and modified condensate storage tanks controlled by a combustion device for the first 90 days surveillance systems must be employed and operational beginning 180 days from commencement of operation after the tank was newly installed, or after the well was newly drilled, re-completed, re-fractured or otherwise stimulated, if uncontrolled actual emissions projected for the first twelve months based on data from the first 90 days of operation from the condensate storage tank are 100 tons or more of uncontrolled VOCs.

I.C.2. The emission estimates and emission reductions required by Section I.D. must be demonstrated using one of the following emission factors:

I.C.2.a. In the 8-Hour Ozone Control Area

I.C.2.a.(i) For atmospheric condensate storage tanks at oil and gas exploration and production operations, a default emission factor of 13.7 pounds of volatile organic compounds per barrel of condensate must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii). The Division may require a more specific emission factor that complies with Section I.C.2.a.(iii).

I.C.2.a.(ii) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations a source may use a specific emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003. The Division may, however, require the source to develop and use a more recent specific emission factor pursuant to Section I.C.2.a.(iii) if such a more recent emission factor would be more reliable or accurate.

I.C.2.a.(iii) Except as otherwise provided in Section I.C.2.a.(i), a specific emission factor is one for which the Division has no objection, and which is based on collection and analysis of a representative sample of the hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.a.(iv) For storage tanks storing produced water or hydrocarbon liquids other than condensate, the most recent Division-approved default emission factors must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii).

I.C.2.a.(v) If the Division has reason to believe that a specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require the use of an alternative emission factor that complies with Section I.C.2.a.(iii).

I.C.2.b. (State Only) For any other Ozone Nonattainment Area or Attainment/Maintenance Areas

I.C.2.b.(i) (State Only) For storage tanks at oil and gas exploration and production operations, the source must use a default basin-specific uncontrolled volatile organic compound emission factor established by the Division unless a site-specific emission factor has been established pursuant to Section I.C.2.b.(iii). If the Division has established no default emission factor, if the Division has reason to believe that the default emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(ii) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, the source must use a site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.(iii). If the Division has reason to believe that the site-specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(iii) (State Only) Establishment of or Updating Approved Emission Factors

I.C.2.b.(iii)(A) (State Only) The Division may require the source to develop and/or use a more recent default basin-specific or site-specific volatile organic compound emission factor pursuant to Section I.C.2.b., if such emission factor would be more reliable or accurate.

I.C.2.b.(iii)(B) (State Only) For storage tanks at oil and gas exploration and production operations, the source may use a site-specific volatile organic compound emission factor for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.b.(iii)(C) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, a source may use a volatile organic compound emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003, or an alternative site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.

I.C.2.b.(iii)(D) (State Only) A default basin-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water or an alternative method, pursuant to a test method approved by the Division, except as otherwise provided in I.C.2.b.(i).

I.C.2.b.(iii)(E) (State Only) A site-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.D. Storage Tank Emission Controls

I.D.1. System-Wide Control Strategy for Condensate Storage Tanks

I.D.1.a. Beginning May 1, 2011, through April 30, 2020, owners and operators of all atmospheric condensate storage tanks that emit greater than or equal to two tons per year of actual uncontrolled volatile organic compounds must employ air pollution control equipment to reduce emissions of volatile organic compounds from atmospheric condensate storage tanks by 90% from uncontrolled actual emissions on a calendar weekly basis May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

Emission reductions are not required for each and every unit, but instead shall be based on overall reductions in uncontrolled actual emissions from all the atmospheric condensate storage tanks associated with the affected operations for which the owner or operator filed, or was required to file, an APEN pursuant to Regulation Number 3, Part A, due to either having exceeded reporting thresholds or retrofitting with air pollution control equipment in order to comply with the system-wide control strategy.

I.D.1.b. The system-wide control strategy does not apply to natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.1.c. The system-wide control strategy does not apply to any owner or operator where the APENs for all of the atmospheric condensate storage tanks associated with the affected operations owned or operated by such person in calendar year 2019 or January 1, 2020, through April 30, 2020, reflect a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the 8-Hour Ozone Control Area.

I.D.2. New and Modified Condensate Tanks

I.D.2.a. Beginning February 1, 2009, through March 1, 2020, owners or operators of any new or modified atmospheric condensate storage tank at exploration and production sites shall collect and control emissions by routing emissions to and operating air pollution control equipment pursuant to Section I.D. The air pollution control equipment shall have a control efficiency of at least 95%, and shall control volatile organic compounds during the first 90 calendar days after commencement of operation of the storage tank, or after the well was re-completed, re-fractured or otherwise stimulated. The air pollution control equipment and associated monitoring equipment required pursuant to Section I.C.1. may be removed after the first 90 calendar days as long as the source can demonstrate compliance with the applicable system-wide standard.

I.D.3. Storage Tank Control Strategy

I.D.3.a. Applicability

I.D.3.a.(i) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.a.(ii) (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total and not subject to Section I.D.3.a.(i) must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.b. Compliance Deadlines

I.D.3.b.(i) A storage tank subject to Section I.D.3.a.(i) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(ii) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(iii) A storage tank subject to Section I.D.3.a.(i) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(iv) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(v) A storage tank subject to Section I.D.3.a.(i) and not otherwise subject to Sections I.D.3.b.(i). or I.D.3.b.(iii) that increases uncontrolled actual emissions to four (4) tons per year VOC or more on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded four (4) tons per year on a rolling twelve-month basis.

I.D.3.b.(vi) (State Only) A storage tank subject to Section I.D.3.a.(ii) and not otherwise subject to Sections I.D.3.b.(ii) or I.D.3.b.(iv) that increases uncontrolled actual emissions to two (2) tons per year VOC based on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded two (2) tons per year on a rolling twelve-month basis.

I.D.3.b.(vii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iii) or I.D.3.b.(v), compliance with Section I.D.3.a.(i) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iii) or I.D.3.b.(v) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(viii) (State Only) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iv) or I.D.3.b.(vi), compliance with Section I.D.3.a.(ii) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iv) or I.D.3.b.(vi) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(ix) This Section I.D.3. does not apply to storage tanks at natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.4. Alternative emissions control equipment and pollution prevention devices and processes installed and implemented after June 1, 2004, shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and/or vapor recovery units to achieve the emission reductions required by this Section I.D., if the following conditions are met:

I.D.4.a. The owner or operator obtains a construction permit authorizing such use of the alternative emissions control equipment or pollution prevention device or process. The proposal for such equipment, device or process shall comply with all regulatory provisions for construction permit applications and shall include the following:

I.D.4.a.(i) A description of the equipment, device or process;

I.D.4.a.(ii) A description of where, when and how the equipment, device or process will be used;

I.D.4.a.(iii) The claimed control efficiency and supporting documentation adequate to demonstrate such control efficiency;

I.D.4.a.(iv) An adequate method for measuring actual control efficiency; and

I.D.4.a.(v) Description of the records and reports that will be generated to adequately track emission reductions and implementation and operation of the equipment, device or process, and a description of how such matters will be reflected in the records and reports required by Section I.F.

I.D.4.b. Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.D.4.c. EPA approves the proposal. The Division shall transmit a copy of the permit application and any other materials provided by the applicant, all public comments, all Division responses and the Division's permit to EPA Region 8. If EPA fails to approve or disapprove the proposal within 45 days of receipt of these materials, EPA shall be deemed to have approved the proposal.

I.E. Monitoring of Storage Tanks and Air Pollution Control Equipment

I.E.1. Applicability

I.E.1.a. The owner or operator of any storage tank that is being controlled pursuant to this Section I. (except storage tanks subject to Section I.D.3.a.(ii)).

I.E.1.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii).

I.E.2. Monitoring Requirements

I.E.2.a. The owner or operator of any storage tank controlled by air pollution control equipment other than a combustion device must follow manufacturer's recommended maintenance. Air pollution control equipment must be periodically inspected to ensure proper maintenance and operation according to the Division-approved operation and maintenance plan.

I.E.2.b. Beginning January 1, 2017, through April 30, 2020, owners or operators of atmospheric condensate storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must conduct and document audio, visual, olfactory (AVO) inspections of the storage tank at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days.

I.E.2.c. Weekly Monitoring Requirements

The owner or operator must inspect or monitor the air pollution control equipment at least weekly to ensure that it is operating properly. The inspection must include and document the following

I.E.2.c.(i) For combustion devices, a check that the pilot light is lit by either visible observation or other means approved by the Division. For devices equipped with an auto-igniter, a check that the auto-igniter is properly functioning.

I.E.2.c.(ii) For combustion devices, a check that the valves for piping of gas to the pilot light are open.

I.E.2.c.(iii) (State Only) In addition to complying with Sections I.E.2.c.(i). and I.E.2.c.(ii)., the owner or operator of tanks controlled pursuant to Section I.D. that have installed combustion devices may use a surveillance system to maintain records on combustion device operation.

I.E.2.c.(iv) For combustion devices, the owner or operator must visually check for the presence or absence of smoke and that the burner tray is not visibly clogged.

I.E.2.c.(v) For vapor recovery units, the owner or operator must check that the unit is operating and that vapors from the storage tank are being routed to the unit.

I.E.2.c.(vi) For all control devices, the owner or operator must check that the valves for the piping from the storage tank to the air pollution control equipment are open.

I.E.2.c.(vii) For all storage tanks, the owner or operator must check that the thief hatch is closed and latched, the pressure relief valve is properly seated, and all vent lines are closed.

I.E.2.c.(viii) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.c.(ix) (State Only) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks subject to Section I.D.3.a.(ii) must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.d. (State Only) For storage tanks equipped with a surveillance system or other Division-approved monitoring system, the owner or operator must check weekly that the system is functioning properly and that necessary information is being collected. Any loss of data or failure to collect required data may be treated by the Division as if the data were not collected.

I.F. Storage Tank Recordkeeping and Reporting

I.F.1. Recordkeeping and Reporting for Tanks Subject to the System-Wide Control Strategy (through April 30, 2020)

The owner or operator shall, at all times, track the emissions and specifically volatile organic compound emissions reductions on a calendar weekly and calendar monthly basis to demonstrate compliance with the applicable emission reduction requirements of the system-wide control strategy. This shall be done by maintaining a Division-approved spreadsheet of information describing the affected operations, the air pollution control equipment being used, and the emission reductions achieved, as follows.

I.F.1.a. The Division-approved spreadsheet shall:

I.F.1.a.(i) List all atmospheric condensate storage tanks subject to the system-wide control strategy by name and AIRS number, or if no AIRS number has been assigned the site location. The spreadsheet also shall list the monthly production volumes for each tank. The spreadsheet shall list the most recent measurement of such production at each tank, and the time period covered by such measurement of production.

I.F.1.a.(ii) List the emission factor used for each atmospheric condensate storage tank. The emission factors shall comply with Section I.C.2.

I.F.1.a.(iii) List the location and control efficiency value for each unit of air pollution control equipment. Each atmospheric condensate storage tank being controlled shall be identified by name and an AIRS number.

I.F.1.a.(iv) List the production volume for each tank, expressed as a weekly and monthly average based on the most recent measurement available. The weekly and monthly average shall be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the refinery purchaser for delivery of condensate from such tank, over the time such delivered condensate was collected. The weekly and monthly average from the most recent measurement will be used to estimate weekly and monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.1.a.(v) Show the calendar weekly and calendar monthly-uncontrolled actual emissions and the calendar weekly and calendar monthly controlled actual emissions for each atmospheric condensate storage tank.

I.F.1.a.(vi) Show the total system-wide calendar weekly and calendar monthly-uncontrolled actual emissions and the total system-wide calendar weekly and calendar monthly controlled actual emissions.

I.F.1.a.(vii) Show the total system-wide calendar weekly and calendar monthly percentage reduction of emissions.

I.F.1.a.(viii) Note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the spreadsheet shall record the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.1.a.(ix) Be maintained in a manner approved by the Division and shall include any other information requested by the Division that is reasonably necessary to determine compliance with the system-wide control strategy.

I.F.1.a.(x) Be updated on a calendar weekly and calendar monthly basis and shall be promptly provided by e-mail or fax to the Division upon its request. The U.S. mail may also be used if acceptable to the Division.

I.F.1.b. Failure to properly install, operate, and maintain air pollution control equipment at the locations indicated in the spreadsheet shall be a violation of this regulation.

I.F.1.c. A copy of each calendar weekly and calendar monthly spreadsheet shall be retained for five years. A spreadsheet may apply to more than one week if there are no changes in any of the required data and the spreadsheet clearly identifies the weeks it covers. The spreadsheet may be retained electronically. However, the Division may treat any loss of data or failure to maintain the Division-approved spreadsheet, as if the data were not collected.

I.F.1.d. Each owner or operator shall maintain records of the inspections required pursuant to Section I.E. and retain those records for five years. These records shall include the time and date of the inspection, the person conducting the inspection, a notation that each of the checks required under Sections I.C. and I.E. were completed and a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

I.F.1.e. (State Only) Each owner or operator shall maintain records of required surveillance system or other monitoring data and shall make these records available promptly upon Division request.

I.F.1.f. (State Only) Each owner or operator shall maintain records on when an atmospheric condensate storage tank is newly installed, or when a well is newly drilled, re-completed, re-fractured or otherwise stimulated. Records shall be maintained per well associated with each tank and the date of first production associated with these activities.

I.F.1.g. Reporting for Tanks Subject to the System-Wide Control Strategy.

On or before April 30, 2020, each owner or operator shall submit a report describing the air pollution control equipment used during calendar year 2019 and how each company complied with the system-wide control strategy during calendar year 2019. On or before August 30, 2020, each owner or operator must submit a report describing the air pollution control equipment used from January 1, 2020, through April 30, 2020, and how each company complied with the system-wide control strategy during that time period. Such reports shall be submitted to the Division on a Division-approved form provided for that purpose.

I.F.1.g.(i) The report shall list all condensate storage tanks subject or used to comply with the system-wide control strategy and the production volumes for each tank. Production volumes may be estimated by the amounts shown on the receipt from refinery purchasers for delivery of condensate from such tanks.

I.F.1.g.(ii) The report shall list the emission factor used for each tank. The emission factors shall comply with Section I.C.2.

I.F.1.g.(iii) The report shall list the location and control efficiency value for each piece of air pollution control equipment, and shall identify the atmospheric condensate storage tanks being controlled by each.

I.F.1.g.(iv) The April 30 report shall show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, 2020.

I.F.1.g.(v) The April 30 report shall show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, 2020.

I.F.1.g.(vi) The April 30 report shall show the calendar monthly total system-wide percentage reduction of emissions for May 1 through September 30 of the previous year, and for the combined periods of January 1 through April 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide percentage reduction of emissions for January 1 through April 30, 2020.

I.F.1.g.(vii) The report shall note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating should be recorded in the report.

I.F.1.g.(viii) The report shall state whether the required emission reductions were achieved on a calendar monthly basis during the preceding year for the April 30 report and for January 1 through April 30, 2020, for the August 30 report. If the required emission reductions were not achieved, the report shall state why not, and shall identify steps being taken to ensure subsequent compliance.

I.F.1.g.(ix) The report shall include any other information requested by the Division that is reasonably necessary to determine compliance with this Section I.

I.F.1.g.(x) A copy of each semi-annual report shall be retained for five years.

I.F.1.g.(xi) In addition to submitting the semi-annual reports, on or before the 30th of each month commencing in June 2007 and ending April 30, 2020, the owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to Sections I.A. and I.D. shall notify the Division of any instances where the air pollution control equipment was not properly functioning during the previous month. The report shall include the time and date that the equipment was not properly operating, the time and date that the equipment was last observed operating properly, and the date and time that the problem was corrected. The report shall also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number of each of the condensate tanks being controlled by the equipment or if no AIRS number has been assigned the site name, and the estimated production from those tanks during the period of non-operation.

I.F.1.g.(xii) Commencing in 2007, on or before April 30 of each year (ending on April 30, 2020), the owner or operator shall submit a list identifying by name and AIRS number or if no AIRS number has been assigned the site name, each condensate storage tank that is being controlled to meet the requirements set forth in Section I.D.1. On the 30th of each month during ozone season (May through September) and on November 30 and February 28 (ending on February 28, 2020), the owner or operator shall submit a list identifying any condensate storage tank whose control status has changed since submission of the previous list.

I.F.1.g.(xiii) (State Only) Semi-annual report submittals shall be signed by a responsible official who shall also sign the Division-approved compliance certification form for atmospheric condensate storage tanks. The compliance certification shall include both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions shall be identified separately from compliance certifications required under the State Implementation Plan.

I.F.1.g.(xiv) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

I.F.1.h. The record-keeping and reporting required in Sections I.F.1. shall not apply to the owner or operator of any natural gas compressor station or natural gas drip station that is authorized to operate pursuant to a construction permit or Title V operating permit issued by the Division if the following criteria are met:

I.F.1.h.(i) Such permits are obtained by the owner or operator on or after the effective date of this provision and contain the provisions necessary to ensure the emissions reductions required by Section I.D.;

I.F.1.h.(ii) The owners and operators of such natural gas compressor stations or natural gas drip stations do not own or operate any exploration and production operation(s); and

I.F.1.h.(iii) Total emissions from atmospheric condensate storage tanks associated with such natural gas compressor stations or drip stations subject to APEN reporting requirements under Regulation Number 3, Part A owned or operated by the same person do not exceed 30 tons per year in the 8-hour Ozone Control Area.

I.F.2. Recordkeeping for storage tanks subject to Section I.D.3.

I.F.2.a. The owner or operator of any storage tank subject to control pursuant to Section I.D.3. (except storage tanks subject to Section I.D.3.a.(ii)) must maintain records and make them available to the Division upon request.

I.F.2.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii) must maintain records and make them available to the Division upon request.

I.F.2.c. Records maintained under this Section I.F.2. must include:

I.F.2.c.(i) The AIRS number for the storage tank. The AIRS number assigned by the Division must be marked on all storage tanks required to file an APEN.

I.F.2.c.(ii) If air pollution control equipment is required to comply with Section I.D.3. visible signage must be located with the control equipment identifying the AIRS number for each storage tank that is being controlled by that equipment.

I.F.2.c.(iii) Records of the inspections required in Section I.E.

I.F.2.c.(iii)(A) The time and date of each inspection.

I.F.2.c.(iii)(B) The person conducting the inspection.

I.F.2.c.(iii)(C) A notation that each of the checks required under Section I.E. were completed.

I.F.2.c.(iii)(D) A description of any problems observed during the inspection, description and date of any corrective actions taken, and name of individual performing corrective actions.

I.F.2.c.(iv) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month totals for each storage tank subject to control under Section I.D.3.

I.F.2.c.(v) The emission factor used for each storage tank. The emission factors must comply with Section I.C.2. and the owner or operator must use the most recent emission factor on file with the Division (i.e., either the default emission factor or the specific emission factor established pursuant to Section I.C.2.a.(iii)).

I.F.2.c.(vi) The control efficiency of each unit of air pollution control equipment and the AIRS number of the storage tank being controlled.

I.F.2.d. (State Only) The owner or operator of each storage tank subject to Section I.D.3. must maintain records of

I.F.2.d.(i) The monthly production volumes for each storage tank, based on the most recent measurement available. The monthly average must be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the purchaser for delivery of hydrocarbon liquids or produced water from such tank, over the time such delivered hydrocarbon liquids or produced water was collected. The monthly average from the most recent measurement will be used to estimate monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.2.d.(ii) Any downtime of air pollution control equipment, including the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.2.d.(iii) Any required surveillance system or other monitoring data.

I.F.2.d.(iv) When a storage tank is installed, or when a well is drilled, re-completed, re-fractured, or otherwise stimulated. Records must be maintained per well associated with each storage tank and the date of commencement of operation associated with these activities.

I.F.3. Reporting for storage tanks subject to Section I.D.3.

I.F.3.a. On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks (except storage tanks subject to Section I.D.3.a.(ii)) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.b. (State Only) On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks subject to Section I.D.3.a.(ii) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.c. The report under this Section I.F.3. must include:

I.F.3.c.(i) The report must list all storage tanks (by AIRS number and location name) controlled pursuant to Section I.D.3. during the previous calendar year (starting calendar year 2020) and

I.F.3.c.(i)(A) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month total for each storage tank.

I.F.3.c.(i)(B) The emission factor used for each storage tank for each month.

I.F.3.c.(i)(C) The control efficiency for the air pollution control equipment for each storage tank.

I.F.3.c.(ii) (State Only) The report must identify any storage tank whose control status has changed, and the date of the change, since submission of the previous report.

I.F.3.c.(iii) (State Only) The report must list the production volume for each storage tank. Production volumes may be estimated by the amounts shown on the receipt from the purchaser.

I.F.3.c.(iv) (State Only) The report must list any downtime of air pollution control equipment, including the date, time, and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating must be recorded in the report.

I.F.3.c.(v) (State Only) The report must list any instances where the air pollution control equipment was not properly functioning, including the date and time the equipment was not properly operating, the date and time the equipment was last observed operating properly, and the date and time the problem was corrected. The report must also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number, or site name if no AIRS number has been assigned, of each storage tank being controlled by the equipment and the estimated production from those storage tanks during the period of non-operation.

I.F.3.c.(vi) (State Only) Reports must be signed by a responsible official who must also sign the Division-approved compliance certification form for storage tanks. The compliance certification includes both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, the certification must include the citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions must be identified separately from compliance certifications required under the State Implementation Plan.

I.F.3.c.(vii) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. must contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

I.G. Natural gas-processing plants located in the 8-hour Ozone Control Area (State Only: or any specific Ozone Nonattainment or Attainment/Maintenance Area) shall comply with requirements of this Section I.G., as well as the requirements of Sections I.B., I.C.1.a., I.C.1.b., I.H., I.J., I.K., and Part E, Section I.A. through C.

I.G.1. For fugitive volatile organic compound emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOO (July 1, 2017) applies, regardless of the date of construction of the affected facility, unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOOa (July 1, 2017).

I.G.2. Air pollution control equipment shall be installed and properly operated to reduce emissions of volatile organic compounds from any atmospheric condensate storage tank (or tank battery) used to store condensate that has not been stabilized that has uncontrolled actual emissions of greater than or equal to two tons per year. Such air pollution control equipment shall have a control efficiency of at least 95%.

I.G.3. Natural gas processing plants within the 8-hour Ozone Control Area constructed before January 1, 2018, must comply with the requirements of Section I.G. beginning January 1, 2019. (State Only: Existing natural gas processing plants within any new Ozone Nonattainment or Attainment/Maintenance Area shall comply with this regulation within three years after the nonattainment designation.)

I.G.4. The provisions of Sections I.B., I.C.1.a., I.C.1.b., I.G., I.H., I.J., I.K., and Part E, Section I.A. through C., apply upon the commencement of operations to any natural gas processing plant that commences operation in the 8-Hour Ozone Control Area or Ozone Nonattainment (State Only: or Attainment/Maintenance Area) after the effective date of this section.

I.H. Emission Reductions from glycol natural gas dehydrators

I.H.1. Beginning May 1, 2005, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in the 8-Hour Ozone Control Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.2. (State Only) Beginning January 30, 2009, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in any Ozone Nonattainment or Attainment/Maintenance Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.3. The control requirements of Sections I.H.1. and I.H.2. apply where:

I.H.3.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than one ton per year; and

I.H.3.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than one ton per year.

I.H.4. For purposes of Section I.H., emissions from still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator shall be calculated using a method approved in advance by the Division.

I.H.5. Monitoring and recordkeeping

I.H.5.a. Beginning January 1, 2017, owners or operators of glycol natural gas dehydrators subject to the control requirements of Sections I.H.1. or I.H.2. must check on a weekly basis that any condenser or air pollution control equipment used to control emissions of volatile organic compounds is operating properly, and document:

I.H.5.a.(i) The date of each inspection;

I.H.5.a.(ii) A description of any problems observed during the inspection of the condenser or air pollution control equipment; and

I.H.5.a.(iii) A description and date of any corrective actions taken to address problems observed during the inspection of the condenser or air pollution control equipment.

I.H.5.b. The owner or operator must check and document on a weekly basis that the pilot light on a combustion device is lit, that the valves for piping of gas to the pilot light are open, and visually check for the presence or absence of smoke.

I.H.5.c. The owner or operator must document the maintenance of the condenser or air pollution control equipment, consistent with manufacturer specifications or good engineering and maintenance practices.

I.H.5.d. The owner or operator must retain records for a period of five years and make these records available to the Division upon request.

I.H.6. Reporting

I.H.6.a. On or before November 30, 2017, and semi-annually by April 30 and November 30 of each year thereafter, the owner or operator must submit the following information for the preceding calendar year (April 30 report) and for May 1 through September 30 (November 30 report) using Division-approved format

I.H.6.a.(i) A list of the glycol natural gas dehydrator(s) subject to Section I.H.;

I.H.6.a.(ii) A list of the condenser or air pollution control equipment used to control emissions of volatile organic compounds from the glycol natural gas dehydrator(s); and

I.H.6.a.(iii) The date(s) of inspection(s) where the condenser or air pollution control equipment was found not operating properly or where smoke was observed.

I.I. The requirements of Sections I.D. through I.F. do not apply to the owner or operator of any natural gas compressor station or natural gas drip station located in an Ozone Nonattainment or Attainment/Maintenance Area if:

I.I.1. Air pollution control equipment is installed and properly operated to reduce emissions of volatile organic compounds from all atmospheric condensate storage tanks (or tank batteries) that have uncontrolled actual emissions of greater than or equal to two tons per year;

I.I.2. The air pollution control equipment is designed to achieve a VOC control efficiency of at least 95% on a rolling 12-month basis and meets the requirements of Sections I.C.1.a. and I.C.1.b;

I.I.3. The owner or operator of such natural gas compressor station or natural gas drip station does not own or operate any exploration and production facilities in the Ozone Non-attainment or Attainment-maintenance Area; and

I.I.4. The owner or operator of such natural gas compressor station or natural gas drip station does the following and maintains associated records and reports for a period of five years:

I.I.4.a. Documents the maintenance of the air pollution control equipment according to manufacturer specifications;

I.I.4.b. Conducts an annual opacity observation once each year on the air pollution control equipment to verify opacity does not exceed 20% during normal operations;

I.I.4.c. Maintains records of the monthly stabilized condensate throughput and monthly actual VOC emissions; and

I.I.4.d. Reports compliance with these requirements to the Division annually.

I.I.5. A natural gas compressor station or natural gas drip station subject to Section I.I. at which a glycol natural gas dehydrator and/or natural gas-fired stationary or portable engine is operated is subject to Sections I.H., I.J., and/or Part E, Section I. A natural gas compressor station subject to Section I.I. is also subject to Section I.L.

I.J. Compressors

I.J.1. Centrifugal compressor

I.J.1.a. Beginning January 1, 2018, uncontrolled actual volatile organic compound emissions from wet seal fluid degassing systems on wet seal centrifugal compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be reduced by at least 95%. A centrifugal compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.1.

I.J.1.b. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must equip the wet seal fluid degassing system with a continuous, impermeable cover that is connected through a closed vent system that routes the emissions from the wet seal fluid degassing system to the process or control device.

I.J.1.c. The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.1.d. The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.1.e. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.1.f. Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.1.f.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.1.f.(ii) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.1.f.(iii) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.1.f.(iv) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.1.g. The owner or operator must conduct monthly inspections of a combustion device used to reduce emissions to ensure the device is operating with no visible emissions.

I.J.1.h. Recordkeeping

I.J.1.h.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.1.h.(i)(A) Identification of each centrifugal compressor using a wet seal system;

I.J.1.h.(i)(B) Each combustion device visible emissions inspection and any resulting responsive actions;

I.J.1.h.(i)(C) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.1.h.(i)(D) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.1.i. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.1.c. through I.J.1.f., I.J.1.h.(i)(C), and I.J.1.h.(i)(D), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.1.j. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.1.a. through I.J.1.i., the owner or operator may comply with wet seal centrifugal compressors emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.J.2. Reciprocating compressor

I.J.2.a. Beginning January 1, 2018, the rod packing on reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be replaced every 26,000 hours of operation or every thirty-six (36) months. A reciprocating compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.2.

I.J.2.a.(i) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed before January 1, 2018, must

I.J.2.a.(i)(A) Begin monitoring the hours of operation starting January 1, 2018; or

I.J.2.a.(i)(B) Conduct the first rod packing replacement required under Section I.J.2. prior to January 1, 2021.

I.J.2.a.(ii) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed after January 1, 2018, must begin monitoring the hours or months of operation upon commencement of operation of the reciprocating compressor.

I.J.2.b. As an alternative to the requirement described in Section I.J.2.a., beginning May 1, 2018, the owner or operator may collect rod packing volatile organic compound emissions using a rod packing emissions collection system that operates under negative pressure and routes the rod packing emissions through a closed vent system to a process.

I.J.2.b.(i) The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.2.b.(ii) The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.2.b.(iii) In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.2.b.(iv) Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.2.b.(iv)(A) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.2.b.(iv)(B) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.2.b.(iv)(C) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.2.b.(iv)(D) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.2.c. Recordkeeping

I.J.2.c.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.2.c.(i)(A) Identification of each reciprocating compressor;

I.J.2.c.(i)(B) The hours of operation or the number of months since the previous rod packing replacement, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure;

I.J.2.c.(i)(C) The date of each rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system;

I.J.2.c.(i)(D) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.2.c.(i)(E) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.2.d. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.2.b., I.J.2.c.(i)(D), and I.J.2.c.(i)(E), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.2.e. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.2.a. through I.J.2.d., the owner or operator may comply with reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.K. Pneumatic pumps

I.K.1. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a natural gas processing plant must ensure the pneumatic pump has a volatile organic compound emission rate of zero.

I.K.2. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a well production facility must reduce volatile organic compound emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to an existing control device or process at the well production facility. Natural gas-driven diaphragm pneumatic pumps that are in operation during any period of time during a calendar day less than 90 days per calendar year are not subject to Section I.K.2.

I.K.2.a. If the control device available onsite is unable to achieve a 95% emission reduction and it is not technically feasible to route the emissions to a process at the well production facility, the owner or operator must still route the pneumatic pump emissions to the existing control device.

I.K.2.b. If the owner or operator subsequently installs a control device or it becomes technically feasible to route the emissions to a process, the owner or operator must reduce volatile organic compound emissions from the pneumatic pump by 95% within thirty (30) days of startup of the control device or of the feasibility of routing emissions to a process at the well production facility.

I.K.2.c. The owner or operator is not required to control pneumatic pump emissions if, through an engineering assessment by a qualified professional engineer, routing a pneumatic pump to a control device or process at the well production facility is shown to be technically infeasible.

I.K.2.d. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must connect the pneumatic pump through a closed vent system that routes the pneumatic pump emissions to the process or control device.

I.K.2.e. The owner or operator must conduct annual visual inspections of the closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices.

I.K.2.f. The owner or operators must conduct annual EPA Method 21 inspections of the closed vent system to determine whether the closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.K.2.g. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.K.2.h. Owners or operators may delay inspection or repair of a closed vent system if:

I.K.2.h.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.K.2.h.(ii) The closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.K.2.h.(iii) The closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.K.2.h.(iv) The closed vent system is inaccessible to inspect or repair because the closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.K.3. Recordkeeping

I.K.3.a. Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.K.3.a.(i) Identification of each natural gas-driven diaphragm pneumatic pump;

I.K.3.a.(ii) For natural gas-driven diaphragm pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year;

I.K.3.a.(iii) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve;

I.K.3.a.(iv) Records of the engineering assessment and certification by a qualified professional engineer that routing natural gas-driven diaphragm pneumatic pump emissions to a control device or process is technically infeasible;

I.K.3.a.(v) Each closed vent system inspection and any resulting responsive actions; and

I.K.3.a.(vi) Each closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such closed vent system.

I.K.4. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.K.2.e. through I.K.2.h., I.K.3.a.(v), and I.K.3.a.(vi), the owner or operator may inspect, repair, and document the closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.K.5. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.K.1. through I.K.4., the owner or operator may comply with natural gas-driven diaphragm pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.L. Leak detection and repair program for well production facilities and natural gas compressor stations located in the 8-hour Ozone Control Area.

I.L.1. Natural gas compressor stations

I.L.1.a. Beginning June 30, 2018, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least quarterly.

I.L.1.b. Owners or operators of natural gas compressor stations constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no later than ninety (90) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted at least quarterly.

I.L.2. Well production facilities

I.L.2.a. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least annually.

I.L.2.b. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

I.L.2.c. For purposes of Sections I.L.2.a. and I.L.2.b., the estimated uncontrolled actual volatile organic compound emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual volatile organic compound emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

I.L.2.d. Owners or operators of well production facilities constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted in accordance with Sections I.L.2.a. and I.L.2.b.

I.L.3. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

I.L.3.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

I.L.3.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

I.L.3.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

I.L.4. Leaks requiring repair: Only leaks from components exceeding the thresholds in Section I.L.4. require repair under Section I.L.5.

I.L.4.a. For EPA Method 21 monitoring, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.b. For infra-red camera monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.c. For other approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in an approval under Section I.L.8.

I.L.4.d. For leaks identified using an approved non-quantitative instrument monitoring method, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section I.L.5. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section I.L.4.a., the leak must be repaired and remonitored in accordance with Section I.L.5.

I.L.4.e. Owners or operators must maintain and operate approved non-quantitative instrument monitoring methods according to manufacturer recommendations.

I.L.5. Repair and remonitoring

I.L.5.a. First attempt to repair a leak must be made no later than five (5) working days after discovery and completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

I.L.5.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

I.L.5.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.L.5.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

I.L.5.b. Within fifteen (15) working days of completion of a repair the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

I.L.5.c. Leaks discovered pursuant to the leak detection methods of Section I.L.4. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section I.L.5. or keep required records in accordance with Section I.L.6.

I.L.6. Recordkeeping

I.L.6.a. Documentation of the initial approved instrument monitoring method inspection for well production facilities and natural gas compressor stations;

I.L.6.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

I.L.6.c. A list of the leaks requiring repair and the monitoring method(s) used to determine the presence of the leak;

I.L.6.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

I.L.6.e. The date the leak was repaired and type of repair method applied;

I.L.6.f. The delayed repair list, including the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list;

I.L.6.g. The date the leak was remonitored and the results of the remonitoring; and

I.L.6.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section I.L.3., an explanation stating why the component is so designated, and the schedule for monitoring such component(s).

I.L.6.i. Records must be maintained for a minimum of five years and made available to the Division upon request.

I.L.7. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section I.L. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

I.L.7.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

I.L.7.b. The total number of inspections performed per inspection frequency tier of well production facilities and the total number of inspections performed at natural gas compressor stations;

I.L.7.c. The total number of identified leaks requiring repair broken out by component type, monitoring method, and inspection frequency tier of well production facility as reported in Section I.L.7.b. and the total number of identified leaks requiring repair at natural gas compressor stations broken out by component type and monitoring method;

I.L.7.d. The total number of leaks repaired for each inspection frequency tier of well production facilities as reported in Section I.L.7.b. and the total number of leaks repaired for natural gas compressor stations;

I.L.7.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facility as reported in Section I.L.7.b. or natural gas compressor station, and the basis for each delay of repair;

I.L.7.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

I.L.7.g. Each report shall be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

I.L.8. Alternative approved instrument monitoring methods may be used in lieu of, or in combination with an infra-red camera, EPA Method 21, or other approved instrument monitoring method to inspect for leaks as required by Section I.L., if the following conditions are met:

I.L.8.a. The proponent of the alternative approved instrument monitoring method applies for a determination of an alternative approved instrument monitoring method or program. The application must include, at a minimum, the following:

I.L.8.a.(i) The proposed alternative approved instrument monitoring method manufacturer information;

I.L.8.a.(ii) A description of the proposed alternative approved instrument monitoring method including, but not limited to:

I.L.8.a.(ii)(A) Whether the proposed alternative approved instrument monitoring method is a quantitative detection method, and how emissions are quantified, or qualitative leak detection method;

I.L.8.a.(ii)(B) Whether the proposed alternative approved instrument monitoring method is commercially available;

I.L.8.a.(ii)(C) Whether the proposed alternative approved instrument monitoring method is approved by other regulatory authorities and for what application (e.g., pipeline monitoring, emissions detected);

I.L.8.a.(ii)(D) The leak detection capabilities, reliability, and limitations of the proposed alternative approved instrument monitoring method, including, but not limited to, the ability to identify specific leaks or locations, detection limits, and any restrictions on use, as well as supporting data;

I.L.8.a.(ii)(E) The frequency of measurements and data logging capabilities of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(F) Data quality indicators for precision and bias of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(G) Quality control and quality assurance procedures necessary to ensure proper operation of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(H) A description of where, when, and how the proposed alternative approved instrument monitoring method will be used; and

I.L.8.a.(ii)(I) Documentation (e.g., field or test data, modeling) adequate to demonstrate the proposed alternative approved instrument monitoring method or program is capable of achieving emission reductions that are at least as effective as the emission reductions achieved by the leak detection and repair provisions in Section I.L.

I.L.8.a.(iii) The Division will transmit a copy of the complete application and any other materials provided by the applicant to EPA.

I.L.8.a.(iv) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.L.8.a.(v) The Division and the EPA approves the proposal. The Division will transmit a copy of the application and any other materials provided by the applicant, all public comments, all Division responses and the Division's approval to EPA Region 8. If EPA fails to approve or disapprove the proposal within six (6) months of receipt of these materials, EPA will be deemed to have approved the proposal.

II. (State Only) Statewide Controls for Oil and Gas Operations

II.A. (State Only) Definitions

II.A.1. "Air Pollution Control Equipment," as used in this Section II., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section II.B.2.e.

II.A.2. "Approved Instrument Monitoring Method," means an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring method or program. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations.

II.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions.

II.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

II.A.5. "Class II Disposal Well Facility" means a facility that injects underground fluids which are brought to the surface in connection with natural gas storage operations or oil or natural gas production and that may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Class II disposal well facilities do not include wells which inject fluids for enhanced recovery of oil or natural gas or for storage of hydrocarbons which are liquid at standard temperature and pressure.

II.A.6. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

II.A.7. “Component” means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

II.A.8. “Connector” means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

II.A.9. “Dump Valve” means a liquid-control valve in a separator that controls liquid level within the separator vessel.

II.A.10. “Dump Event” means the opening of a dump valve allowing liquid to flow from a separator equipped with a dump valve to a storage tank.

II.A.11. “Glycol Natural Gas Dehydrator” means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

II.A.12. “Infra-red Camera” means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

II.A.13. “Hydrocarbon Liquid” means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.

II.A.14. “Natural Gas Compressor Station” means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

II.A.15. “Normal Operation” means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

II.A.16. “Occupied Areas” means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

II.A.17. “Open-Ended Valve or Line” means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

II.A.18. “Produced Water” means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

II.A.19. “Reciprocating Compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

II.A.20. “Stabilized” when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

II.A.21. “Storage Tank” means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

II.A.22. “Storage Tank Measurement System” means equipment and methods used to determine the quantity and quality of the liquids inside a storage tank without requiring direct access through the storage tank thief hatch.

II.A.23. “Storage Vessel” means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

II.A.24. “Visible Emissions” means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation, pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor.

II.A.25. “Vapor Collection and Return System” means a closed system designed to control the release of VOCs displaced from a vessel during transfer of hydrocarbon liquids by using the transferred hydrocarbon liquids for direct displacement to force vapors from the vessel being loaded into either the storage tank being unloaded or to air pollution control equipment.

II.A.26. “Well Production Facility” means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

II.B. (State Only) General Provisions

II.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.B.1.a. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

II.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

II.B.2. General requirements for air pollution control equipment used to comply with Section II.

II.B.2.a. All air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of VOCs and other hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

II.B.2.b. If a combustion device is used to control emissions of VOCs and other hydrocarbons, it must be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

II.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division’s discretion for good cause shown.

II.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons must be equipped with and operate an auto-igniter as follows

II.B.2.d.(i) All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device.

II.B.2.d.(ii) All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

II.B.2.e. Alternative emissions control equipment will qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section II., if the Division approves the equipment, device, or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section II.

II.B.3. Requirements for compressor seals and open-ended valves or lines

II.B.3.a. Beginning January 1, 2015, each open-ended valve or line at well production facilities and natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line. Alternatively, an open-ended valve or line may be treated as if it is a "component" as defined in Section II.A.7., and may be monitored under the provisions of Section II.E.

II.B.3.b. Beginning January 1, 2015, uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter.

II.B.3.c. Beginning January 1, 2015, the rod packing on any reciprocating compressor located at a natural gas compressor station must be replaced every 26,000 hours of operation or every thirty-six (36) months, unless the reciprocating compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

II.B.4. Oil refineries are not subject to Section II.

II.B.5. Glycol natural gas dehydrators that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63 (December 17, 2006), a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 (December 17, 2006) are not subject to Section II., except for the leak detection and repair requirements in Section II.E.

II.C. Emission reduction from storage tanks at oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.C.1. Control and monitoring requirements for storage tanks

II.C.1.a. (State Only) Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that has a control efficiency of at least 95% for VOCs.

II.C.1.b. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.

II.C.1.b.(i) (State Only) Control requirements of Section II.C.1.b. must be achieved in accordance with the following schedule:

II.C.1.b.(i)(A) A storage tank constructed on or after May 1, 2014, must be in compliance within ninety (90) days of the date that the storage tank commences operation.

II.C.1.b.(i)(B) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

II.C.1.b.(i)(C) A storage tank not otherwise subject to Sections II.C.1.b.(i)(A) or II.C.1.b.(i)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve-month basis after May 1, 2014, must be in compliance within sixty (60) days of discovery of the emissions increase.

II.C.1.b.(ii). Control requirements within ninety (90) days of commencement of operation.

II.C.1.b.(ii)(A) Beginning May 1, 2014, through March 1, 2020, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after commencement of operation. The air pollution control equipment must achieve a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after commencement of operation.

II.C.1.b.(ii)(B) The air pollution control equipment and any associated monitoring equipment required pursuant to Section II.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section II.C.1.b.

II.C.1.c. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to March 1, 2020.

II.C.1.c.(i) Control requirements of Section II.C.1.c. must be achieved in accordance with the following schedule

II.C.1.c.(i)(A) A storage tank constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

II.C.1.c.(i)(B) A storage tank constructed before March 1, 2020, that is not already controlled under Sections I.D. or II.C.1.b. must be in compliance by May 1, 2021.

II.C.1.c.(i)(C) A storage tank not otherwise subject to Sections II.C.1.c.(i)(A) or II.C.1.c.(i)(B) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B) must be in compliance within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.1.c.(ii) If air pollution control equipment is not installed by the applicable compliance date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C), compliance with Section II.C.1.c. may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

II.C.1.c.(iii) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.

II.C.1.d. (State Only) Beginning May 1, 2014, or the applicable compliance date in Sections II.C.1.b.(i) or II.C.1.c.(i), whichever comes later, owners or operators of storage tanks subject to Section II.C.1. must conduct audio, visual, olfactory (AVO) and additional visual inspections of the storage tank and any associated equipment (e.g., separator, air pollution control equipment, or other pressure reducing equipment) at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days. Monitoring is not required for storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e. The additional visual inspections must include, at a minimum:

II.C.1.d.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly sealed.

II.C.1.d.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment.

II.C.1.d.(iii) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

II.C.1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open.

II.C.1.d.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

II.C.1.d.(vi) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, visual observation of the dump valve(s) of the last separator(s) before the storage tank(s) to ensure the dump valve is free of debris and not stuck open. The owner or operator is not required to observe the actuation of the dump valve during this inspection; however, if a dump event occurs during the inspection, the owner or operator must confirm proper operation of the valve.

II.C.1.d.(vii) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, a check for the presence of liquids in liquid knockout vessels that do not drain automatically, underground lines, and aboveground piping.

II.C.1.d.(vii)(A) For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. If liquids are present above the low level indication point, drain liquids.

II.C.1.d.(vii)(B) For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids.

II.C.1.d.(vii)(C) For underground lines and aboveground piping that is not sloped to a liquid knockout or tank and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids and drain liquids as needed.

II.C.1.d.(vii)(D) For underground lines and aboveground piping that is not sloped to a liquid knockout vessel or tank and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids quarterly.

II.C.1.e. (State Only) If storage tanks or associated equipment is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor such equipment until it becomes feasible to do so.

II.C.1.e.(i) Difficult to monitor means it cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

II.C.1.e.(ii) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.C.1.e.(iii) Inaccessible to monitor means buried, insulated, or obstructed by equipment or piping that prevents access by monitoring personnel.

II.C.2. (State Only) Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections I.D. or II.C.1.

II.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section II.C.2.b.(ii).

II.C.2.a.(i) Venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which:

II.C.2.a.(i)(A) Are primarily the result of over-pressurization, whether related to design, operation, or maintenance; or

II.C.2.a.(i)(B) Are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole).

II.C.2.a.(ii) When emissions from a controlled storage tank are observed, the Division may require the owner or operator to submit sufficient information demonstrating whether or not the emissions were primarily the result of over-pressurization. Absent a demonstration that such emissions were not primarily the result of over-pressurization, such emissions will be considered venting for purposes of Section II.C.2.a.

II.C.2.a.(iii) When venting is observed, the owner or operator must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. If the venting was observed using an approved instrument monitoring method, the confirmation must be made using an approved instrument monitoring method.

II.C.2.b. Owners or operators of storage tanks subject to the control requirements of Sections I.D., II.C.1.a, II.C.1.b., or II.C.1.c. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section II.C.2.a. Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed.

II.C.2.b.(i) STEM plans must include selected control technologies, monitoring practices, operational practices, and/or other strategies; an analysis of the engineering design of the storage tank and air pollution control equipment; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument monitoring methods following the applicable schedule in Section II.C.2.b.(ii).

II.C.2.b.(ii) Owners or operators must achieve the requirements of Sections II.C.2.a. and II.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule

II.C.2.b.(ii)(A) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed on or after May 1, 2014, must comply with the requirements of Section II.C.2.a. by the date the storage tank commences operation. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of the date that the storage tank commences operation.

II.C.2.b.(ii)(B) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed before May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2015.

II.C.2.b.(ii)(C) A storage tank subject to Section II.C.1.c. and constructed on or after March 1, 2020, must comply with the requirements of Section II.C.2.a. by commencement of operation of the storage tank. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of commencement of operation of the storage tank.

II.C.2.b.(ii)(D) A storage tank subject to Sections II.C.1.c. and I.D.3. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

II.C.2.b.(ii)(E) A storage tank subject to Section II.C.1.c. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2021. Approved instrument monitoring method inspections of the storage tank must begin in 2021.

II.C.2.b.(ii)(F) A storage tank with uncontrolled actual emissions of VOCs equal to or greater than six (6) and less than or equal to twelve (12) tons per year must begin semi-annual approved instrument monitoring method inspections in 2020.

II.C.2.b.(ii)(G) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) or II.C.2.b.(ii)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis..

II.C.2.b.(ii)(H) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) through II.C.2.b.(ii)(F) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B), must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.2.b.(ii)(I) Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the inspection frequency in Table 1.

Table 1 – Storage Tank Inspections	
Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Method Inspection Frequency
≥ 2 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e.

II.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy(ies) are designed to minimize emissions from storage tanks and associated equipment at the facility(ies), including thief hatches and pressure relief devices.

II.C.3. (State Only) Recordkeeping: The owner or operator of each storage tank subject to Sections I.D. or II.C. must maintain records of STEM, if applicable, including the plan, any updates, and the certification, and make them available to the Division upon request. In addition, for a period of two (2) years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including

II.C.3.a. The AIRS ID for the storage tank.

II.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance, gauging (unless use of a storage tank measurement system is required pursuant to and the operator complies with Section II.C.4.), or safety of personnel and equipment.

II.C.3.c. The date and duration of any period where the air pollution control equipment is not operating.

II.C.3.d. Records of the inspections required in Sections II.C.1.d. and II.C.2.b.(ii), including the time and date of each inspection and a description of any problems observed, description and date of any corrective action(s) taken, and name of employee or third party performing corrective action(s).

II.C.3.e. Where a combustion device is being used, the date and result of any EPA Method 22 test or investigation pursuant to Section II.C.1.d.(v).

II.C.3.f. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions, including the dates and results of action(s) taken and the monitoring used to confirm the action(s) were successful.

II.C.3.g. A list of equipment associated with the storage tank that is designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.C.1.e., an explanation stating why the equipment is so designated, and the plan for monitoring such equipment.

II.C.3.h. Records of any exemption, and associated documentation, applied for under Section II.C.1.c.(iii).

II.C.4. (State Only) Storage tank measurement system requirements at well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.4.a. Applicability

II.C.4.a.(i) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after May 1, 2020, and at any facilities that are modified on or after May 1, 2020, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quantity of liquids in the storage tank(s).

II.C.4.a.(ii) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after January 1, 2021, and at any facilities that are modified on or after January 1, 2021, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quality and quantity of liquids in the storage tank(s).

II.C.4.b. Owner or operators subject to the storage tank measurement system requirements in Section II.C.4.a., must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage tank(s).

II.C.4.c. Operators may inspect, test, and/or calibrate the storage tank measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Section II.C.4.b.

II.C.4.d. The owner or operator must install signage at or near the storage tank that indicates which equipment and method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.4.e. The owner or operator must develop and implement an annual training program for employees and/or third parties conducting activities subject to Section II.C.4. that includes, at a minimum, operating procedures for each type of system.

II.C.4.f. Owner or operators must retain records for at least two (2) years and make such records available to the Division upon request, including

II.C.4.f.(i) Date of construction of the storage vessel or facility.

II.C.4.f.(ii) Description of the storage tank measurement system used to comply with Section II.C.4.a.

II.C.4.f.(iii) Date(s) of storage tank measurement system inspections, testing, and/or calibrations pursuant to Section II.C.4. c.

II.C.4.f.(iv) Manufacturer specifications regarding storage tank measurement system inspections, and/or calibrations, if followed pursuant to Section II.C.4.c.

II.C.4.f.(v) Records of the annual training program, including the date and names of persons trained.

II.C.5. (State Only) Storage tank hydrocarbon liquids loadout requirements at Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.5.a. Owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with a hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

Owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

II.C.5.a.(i) Compliance with Section II.C.5. must be achieved in accordance with the following schedule

II.C.5.a.(i)(A) Facilities constructed or modified on or after May 1, 2020, must be in compliance by commencement of operation.

II.C.5.a.(i)(B) Facilities constructed before May 1, 2020, must be in compliance by May 1, 2021.

II.C.5.a.(i)(C) Class II disposal well facilities constructed or modified on or after January 1, 2021, must be in compliance by commencement of operation.

II.C.5.a.(i)(D) Class II disposal well facilities constructed before January 1, 2021, must be in compliance by May 1, 2021.

II.C.5.a.(i)(E) Facilities not subject to Sections II.C.5.a.(i)(A) or II.C.5.a.(i)(B) that exceed the hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from loadout upon exceeding the loadout threshold.

II.C.5.a.(i)(F) Facilities not subject to Sections II.C.5.a.(i)(C) or II.C.5.a.(i)(D) that exceed the hydrocarbon liquids loadout to transport vehicles emissions threshold of greater than or equal to two (2) tons uncontrolled actual VOC emissions per year on a rolling 12-month basis must control emissions from loadout within sixty (60) days of the first day of the month after which loadout emissions exceeded the loadout threshold.

II.C.5.a.(ii) Storage tanks must operate without venting at all times during loadout.

II.C.5.a.(iii) The owner or operator must, as applicable:

II.C.5.a.(iii)(A) Install and operate the vapor collection and return equipment to collect vapors during the loadout of hydrocarbon liquids to tank compartments of outbound transport vehicles and to route the vapors to the storage tank or air pollution control equipment.

II.C.5.a.(iii)(B) Include devices to prevent the release of vapor from vapor recovery hoses not in use.

II.C.5.a.(iii)(C) Use operating procedures to ensure that hydrocarbon liquids cannot be transferred to transport vehicles unless the vapor collection and return system is in use.

II.C.5.a.(iii)(D) Operate all recovery and disposal equipment at a back-pressure less than the pressure relief valve setting of transport vehicles.

II.C.5.a.(iii)(E) The owner or operator must inspect onsite loading equipment to ensure that hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loadout. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv) Loadout observations and operator training

II.C.5.a.(iv)(A) The owner or operator must observe loadout to confirm that all storage tanks operate without venting when loadout operations are active. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv)(B) If observation of loadout is not feasible, the owner or operator must document the annual loadout frequency and the reason why observation is not feasible and inspect the facility within 24 hours after loadout to confirm that all storage tank thief hatches (or other access point to the tank) are closed and latched.

II.C.5.a.(iv)(C) The owner or operator must install signage at or near the loadout control system that indicates which loadout control method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.5.a.(iv)(D) The owner or operator must develop and implement an annual training program for employees and/or third parties conducting loadout activities subject to Section II.C.5. that includes, at a minimum, operating procedures for each type of loadout control system.

II.C.5.a.(v) Owners or operators must retain records for at least two (2) years and make such records available to the Division upon request.

II.C.5.a.(v)(A) Records of the annual facility hydrocarbon liquids loadout to transport vehicles throughput.

II.C.5.a.(v)(B) Inspections, including a description of any problems found and their resolution, required under Sections II.C.5.a.(iii) and II.C.5.a.(iv) must be documented in a log.

II.C.5.a.(v)(C) Records of the infeasibility of observation of loadout.

II.C.5.a.(v)(D) Records of the frequency of loadout.

II.C.5.a.(v)(E) Records of the annual training program, including the date and names of persons trained.

II.C.5.a.(v)(F) Records of class II disposal well facility VOC emissions from hydrocarbon liquids loadout to transport vehicles on a rolling 12-month basis.

II.C.5.a.(vi) Air pollution control equipment used to comply with this Section II.C.5. must comply with Section II.B., be inspected in accordance with Sections II.C.1.d.(ii) through (v), and achieve a hydrocarbon control efficiency of 95%.

II.D. (State Only) Emission reductions from glycol natural gas dehydrators

II.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

II.D.2. The control requirement in Section II.D.1. apply where:

II.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

II.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

II.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:

II.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and

II.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.

II.D.4. The control requirement in Section II.D.3. apply where:

II.D.4.a. Uncontrolled actual emissions of VOCs from a glycol natural gas dehydrator constructed on or after May 1, 2015, are equal to or greater than two (2) tons per year. Such glycol natural gas dehydrators must be in compliance with Section II.D.3. by the date that the glycol natural gas dehydrator commences operation.

II.D.4.b. Uncontrolled actual emissions of VOCs from a single glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

II.D.4.c. For purposes of Sections II.D.3. and II.D.4.:

II.D.4.c.(i) Building Unit means a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

II.D.4.c.(ii) A Designated Outside Activity Area means an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government had established as a designated outside activity area by the COGCC; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

II.E. (State Only) Leak detection and repair program for well production facilities and natural gas compressor stations

II.E.1. The following provisions of Section II.E. apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

II.E.2. Owners or operators of well production facilities or natural gas compressor stations that monitor components as part of Section II.E. may estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

II.E.3. Beginning January 1, 2015, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method, in accordance with the following schedule

II.E.3.a. Approved instrument monitoring method inspections must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

II.E.3.a.(i) Annual approved instrument monitoring method inspections at natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015. Annual inspections must be conducted through calendar year 2019.

II.E.3.a.(ii) Beginning calendar year 2020, owners or operators of natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must conduct semi-annual approved instrument monitoring method inspections.

II.E.3.b. Approved instrument monitoring method inspections must begin within thirty (30) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than fifty (50) tons per year.

II.E.3.c. Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table 2.

II.E.3.d. For purposes of Section II.E.3., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table 2 – Natural Gas Compressor Station Component Inspections

Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and $\leq$ 12	Semi-annually
> 12 and $\leq$ 50	Quarterly
> 50	Monthly

II.E.4. Requirements for well production facilities

II.E.4.a. Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequencies in Table 3.

II.E.4.b. Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within ninety (90) days of the Phase-In Schedule in Table 3; within thirty (30) days for well production facilities subject to monthly approved instrument monitoring method inspections; or by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 3.

II.E.4.c. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) but less than or equal to twelve (12) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

II.E.4.d. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, and located within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.

II.E.4.e. The estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Table 3 – Well Production Facility Component Inspections				
Thresholds (per II.E.4.d.)				
Well production facilities without storage tanks (rolling twelve-month tpy)	Well production facilities with storage tanks (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and < 2	> 0 and < 2	One time	Monthly	January 1, 2016
≥ 2 and ≤ 12	≥ 2 and ≤ 12	Semi-annually	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area	> 2 and < 12, located within 1,000 feet of an occupied area	Quarterly	Monthly	* begins in 2020
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 20	> 50	Monthly		January 1, 2015

II.E.5. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

II.E.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

II.E.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.E.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

II.E.6. Leaks requiring repair: Leaks must be identified utilizing the methods listed in Section II.E.6. Only leaks from components exceeding the thresholds in Section II.E.6. require repair under Section II.E.7.

II.E.6.a. For EPA Method 21 monitoring, at facilities constructed before May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 2,000 parts per million (ppm) not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation, except for well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.b. For EPA Method 21 monitoring, at facilities constructed on or after May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.c. For infra-red camera and AVO monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.d. For other Division approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in the Division's approval.

II.E.6.e. Except as provided in Section II.E.6.f., for leaks identified using an approved non-quantitative instrument monitoring method or AVO, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.a. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section II.E.6., the leak must be repaired in accordance with Section II.E.7.a. and remonitored in accordance with Section II.E.7.c.

II.E.6.f. Beginning on March 1, 2021, for leaks identified using an approved non-quantitative instrument monitoring method or AVO at a well production facility located within 1,000 feet of an occupied area, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.b. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Sections II.E.6.a. through II.E.6.d., the leak must be repaired as follows and remonitored in accordance with Section II.E.7.c.

II.E.6.f.(i) If EPA Method 21 indicates a leak greater than 500 ppm and less than 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.a.

II.E.6.f.(ii) If EPA Method 21 is not performed or indicates a leak greater than or equal to 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.b

II.E.7. Repair and remonitoring

II.E.7.a. Except as provided in Section II.E.7.b., the first attempt to repair a leak must be made no later than five (5) working days after discovery and repair of a leak discovered on or after January 1, 2018, completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

II.E.7.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

II.E.7.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

II.E.7.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

II.E.7.b. For leaks requiring repair pursuant to Section II.E.6.f., the first attempt to repair must be made as soon as practicable but no later than five (5) working days after discovery and completed within five (5) working days after discovery. If repair is not completed within five (5) working days after discovery, the owner or operator must use other means to stop the leak including, but not limited to, isolating the component or shutting in the well, unless such other means will cause greater emissions.

II.E.7.b.(i) If the owner or operator cannot repair or stop the leak within five (5) working days after discovery, the owner or operator must notify the local government with jurisdiction over the location and the Division as soon as possible, but no later than seven (7) working days after the leak is discovered. The notice must include

II.E.7.b.(i)(A) Identification of the facility, the leaking component, and contact information of the owner or operator representative;

II.E.7.b.(i)(B) The concentration of hydrocarbons using EPA Method 21, if available;

II.E.7.b.(i)(C) Instructions to access the infrared camera video footage of the leak, if available;

II.E.7.b.(i)(D) The approximate distance of the facility to the closest occupied area that is not an outdoor area;

II.E.7.b.(i)(E) The basis for the delay of repair and justification for not isolating the component or shutting in the well; and

II.E.7.b.(i)(F) The estimated date of repair.

II.E.7.c. Within fifteen (15) working days of completion of a repair, the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

II.E.7.d. Leaks discovered pursuant to the leak detection methods of Section II.E.6. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section II.E.7. or keep required records in accordance with Section II.E.8.

II.E.8. Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

II.E.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

II.E.8.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.E.8.c. A list of the leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak;

II.E.8.d. The date and result of any EPA Method 21 monitoring relied upon to demonstrate a leak is not subject to Section II.E.7.b.;

II.E.8.e. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

II.E.8.f. The date the leak was repaired and for leaks discovered and repaired on or after January 1, 2018, the type of repair method applied;

II.E.8.g. Documentation of actions taken pursuant to Section II.E.7.b. to stop a leak that was not repaired within five (5) working days after discovery or documentation that such actions would cause greater emissions;

II.E.8.h. Copies of all notices submitted pursuant to Section II.E.7.b.(i) and the infrared camera video footage of leaks that required notice pursuant to Section II.E.7.b.(i);

II.E.8.i. The delayed repair list, including the basis for placing leaks on the list;

II.E.8.i.(i) For leaks discovered on or after January 1, 2018, the delayed repair list must include the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

II.E.8.i.(ii) For leaks discovered after March 1, 2021, that require repair pursuant to Section II.E.7.b., the delayed repair list must include the date and duration of leaks for which repairs were not completed within five (5) working days after discovery, and the schedule for repairing the leak.

II.E.8.j. The date the leak was remonitored and the results of the remonitoring;

II.E.8.k. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.E.5., an explanation stating why the component is so designated, and the schedule for monitoring such component(s); and

II.E.8.l. Documentation of the owner or operator's proximity analysis, if applicable, including the date of the initial and any subsequent analysis and a description of the methodology used for the analysis.

II.E.9. Reporting. The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must submit a single annual report using the Division-approved format on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

II.E.9.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

II.E.9.b. The total number of inspections performed per inspection frequency tier of well production facilities, including the number of facilities inspected in accordance with Section II.E.4.d., and inspection frequency tier of natural gas compressor stations;

II.E.9.c. The total number of identified leaks requiring repair, broken out by component type, monitoring method, and inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.d. The total number of leaks repaired for each inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations, and the basis for each delay of repair. This total does not include leaks that have been stopped through other means, as specified in Section II.E.7.b.;

II.E.9.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

II.E.9.g. Each report must be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete

II.F. Control of emissions from well production facilities

Well Operation and Maintenance: On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from commencement of operation by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

II.G. (State Only) Emissions during downhole well maintenance, well liquids unloading events, and well plugging

II.G.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with downhole well maintenance, well liquids unloading, and well plugging (beginning January 31, 2020), unless emitting is necessary for safety.

II.G.1.a. During liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without emitting. If these methods are not successful in unloading the liquids from the well, the well may emit in order to create the necessary differential pressure to bring the liquids to the surface.

II.G.1.b. The owner or operator must be present on-site during any planned downhole well maintenance, well liquids unloading, or well plugging event and must ensure that any emissions from the well associated with the event are limited to the maximum extent practicable.

II.G.2. Recordkeeping

II.G.2.a. Through January 31, 2020, the owner or operator must keep records of the cause, date, time, and duration of venting events under Section II.G. Records must be kept for two (2) years and made available to the Division upon request.

II.G.2.b. Beginning January 31, 2020, or the date specified in Section II.G.2.b.(iii), the owner or operator must keep the following records for two (2) years and make records available to the Division upon request.

II.G.2.b.(i) The cause of emissions (i.e., downhole well maintenance, well liquids unloading, well plugging), date, time, and duration of emissions under Section II.G.

II.G.2.b.(ii) The best management practices used to minimize hydrocarbon emissions or the safety needs that prevented the use of best management practices.

II.G.2.b.(iii) Beginning July 1, 2020, the emissions associated with well liquids unloading, downhole well maintenance, and well plugging.

II.G.3. Reporting

II.G.3.a. The owner or operator must submit a single annual report using a Division-approved format on or before June 30th of each year (beginning June 30th, 2021) that includes the following information regarding each downhole well maintenance, well liquids unloading, and well plugging event conducted the previous calendar year that resulted in emissions.

II.G.3.a.(i) The API number of the well and the AIRS number of any associated storage tanks.

II.G.3.a.(ii) Whether the emissions occurred due to downhole well maintenance, well liquids unloading, or well plugging.

II.G.3.a.(iii) The date, time, and duration of the downhole well maintenance, well liquids unloading, or well plugging event.

II.G.3.a.(iv) The best management practices used to minimize emissions.

II.G.3.a.(v) Safety needs that prevented the use of best management practices to minimize emissions, if applicable.

II.G.3.a.(vi) An estimate of the volume of natural gas, VOC, NOx, N2), CO2, CO, ethane, and methane emitted from the well associated with well liquid unloading activities, downhole well maintenance, and well plugging event and the emission factor or calculation methodology used to determine the volume of natural gas and emissions.

III. Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

III.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B. Definitions

III.B.1. "Affected Operations" means pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B.2. "Continuous Bleed" means a continuous bleed rate of natural gas from a pneumatic controller that is designed to bleed natural gas continuously.

III.B.3. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

III.B.4. (State Only) "Enhanced Response" means to return a pneumatic controller to proper operation and includes but is not limited to, cleaning, adjusting, and repairing leaking gaskets, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

III.B.5. "High-Bleed Pneumatic Controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

III.B.6. (State Only) "Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release natural gas to the atmosphere as part of the actuation cycle.

III.B.7. "Low-Bleed Pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

III.B.8. “Natural Gas Processing Plant” means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

III.B.9. “No-Bleed Pneumatic Controller” means any pneumatic controller that is not using hydrocarbon gas as the valve’s actuating gas.

III.B.10. (State Only) “Non-emitting Controller” means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.

III.B.11. “Pneumatic Controller” means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

III.B.12. (State Only) “Routed Pneumatic Controller” means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.

III.B.13. “Self-contained Pneumatic Controller” means a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.

III.B.14. (State Only) “Wellhead” means the piping, casing, tubing and connected valves supporting or controlling the operation of an oil and/or natural gas well. The wellhead does not include other process equipment at the wellhead site.

III.C. Emission Reduction Requirements

Owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

III.C.1. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.1.c.

III.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section III.C.1.c.

III.C.1.c. All high-bleed pneumatic controllers that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.

III.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.2. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.C.2.a. All pneumatic controllers placed in service on or after January 1, 2018, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.2.c.

III.C.2.b. All pneumatic controllers with a bleed rate greater than zero in service prior to January 1, 2018, must be replaced or retrofit such that the pneumatic controller has a natural gas bleed rate of zero by May 1, 2018, unless allowed pursuant to Section III.C.2.c.

III.C.2.c. All pneumatic controllers with a natural gas bleed rate greater than zero that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.2.c.(i) For pneumatic controllers with a natural gas bleed rate greater than zero in service prior to January 1, 2018, the owner or operator must submit justification for pneumatic controllers to remain in service due to safety and /or process purposes by May 1, 2018.

III.C.2.c.(ii) For pneumatic controllers with a natural gas bleed rate greater than zero placed in service on or after January 1, 2018, the owner or operator must submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.3. (State Only) Statewide:

III.C.3.a. Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014 and before May 1, 2021, must:

III.C.3.a.(i) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible.

III.C.3.a.(ii) If on-site electrical grid power is not being used or a no-bleed pneumatic controller is not technically and economically feasible, utilize pneumatic controllers that emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.a.(iii) For purposes of Section III.C.3.a.(ii), instead of a low-bleed pneumatic controller, owners or operators may utilize a natural gas-driven intermittent pneumatic controller.

III.C.3.a.(iv) Utilizing self-contained pneumatic controllers satisfies Section III.C.3.a.(i).

III.C.3.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, must be replaced or retrofitted by May 1, 2015, such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.3.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015.

III.C.3.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes thirty (30) days prior to installation.

III.C.4. (State Only) Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations

III.C.4.a. Except as provided in Section III.C.4.e.(i), the following facilities must use only non-emitting controllers:

III.C.4.a.(i) Well production facilities that commence operations on or after May 1, 2021;

III.C.4.a.(ii) Well production facilities that receive production from a well that first begins production or is recompleted or refractured on or after May 1, 2021; and

III.C.4.a.(iii) Natural gas compressor stations that commence operations or increase compression horsepower on or after May 1, 2021.

III.C.4.b. Each well production facility and natural gas compressor station with non-emitting controllers used to satisfy the requirements of Sections III.C.4.a.(i) through (iii) must contain on-site signage indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4. This Section III.C.4.b does not apply to operator's subject to Section III.C.4.d.(vi).

III.C.4.c. Company-Wide Non-Emitting Controller Program for Well Production Facilities That Commenced Operation Before May 1, 2021

III.C.4.c.(i) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 1.

III.C.4.c.(ii) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operations before May 1, 2021, must:

III.C.4.c.(ii)(A) Determine Historic Facility Production for each existing well production facility that commenced operation before May 1, 2021.

III.C.4.c.(ii)(A)(1) Historic Facility Production at each existing well production facility which first began production during 2018 or earlier must be based on total liquids production (summing total barrels of oil and water produced through the well production facility) for the calendar year 2019.

III.C.4.c.(ii)(A)(2) Notwithstanding Section III.C.4.c.(ii)(A)(1), for any well production facility to which a well first began production during 2019, 2020 or by May 1, 2021, historic facility production must be based on the production for the first twelve (12) months beginning with the date of first production of the latest well to begin production prior to May 1, 2021.

III.C.4.c.(ii)(A)(3) Notwithstanding Sections III.C.4.c.(ii)(A)(1) and (2), for any well production facility to which a well first began production during 2019, 2020, or by May 1, 2021, if twelve (12) months since date of first production of the latest well to begin production has not passed as of May 1, 2021, then the owner or operator must use an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

III.C.4.c.(ii)(B) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all existing well production facilities that commenced operation before May 1, 2021.

III.C.4.c.(ii)(C) Determine the percentage of total liquids production for each existing facility (the Facility Percent Production) by dividing the Historic Facility Production for that facility by the Total Historic Production.

III.C.4.c.(ii)(D) Determine the Historic Non-Emitting Facility Percent Production.

III.C.4.c.(ii)(D)(1) If the well production facility, including all wellheads flowing to the well production facility, uses only non-emitting controllers, then the Facility Percent Production should be designated as Historic Non-Emitting Facility Percent Production.

III.C.4.c.(ii)(D)(2) In making the determination in Section III.C.4.c.(ii)(D)(1), pneumatic controllers that meet the conditions in Section III.C.4.e.(i) need not be considered.

III.C.4.c.(ii)(E) Determine the Total Historic Non-Emitting Facility Percent Production percentage by summing the Historic Non-Emitting Facility Percent Production for all well production facilities that commenced operation prior to May 1, 2021. The Total Historic Non-Emitting Facility Percent Production determines an owner or operators' May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production, as set forth in Table 1.

III.C.4.c.(iii) Owners or operators must demonstrate compliance with Table 1's May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production through any combination of (1) retrofitting well production facilities to utilize non-emitting controllers or (2) plugging and abandoning an existing well production facility.

III.C.4.c.(iv) An owner or operator that demonstrates that its total statewide oil and natural gas production averages 15 barrels of oil equivalent or less per day per well is not subject to the requirements of Sections III.C.4.c.(i) through (iii). To calculate average statewide oil and natural gas production per day per well, an owner or operator must sum all oil and natural gas production for calendar year 2019 in barrels of oil equivalent, divide by three hundred and sixty-five, and divide by the number of wells the owner or operator operated statewide that produced hydrocarbons in 2019.

III.C.4.c.(v) If a well production facility for which production was included in a calculation of achieving a Total Required Non-Emitting Facility Percent Production target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the well production facility to show compliance with Table 1, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgment or certification within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the well production facility to show compliance with Table 1.

In each submission of the updated Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller

Compliance Plan, the owner or operator will provide the date (month and year) when a well production facility was transferred since the last submission and whether or not the well production facility contributed or will contribute towards achieving the Total Required Non-Emitting Facility Percent Production. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.c.(vi) For each facility designated as contributing to Historic Non-Emitting Facility Percent Production, the owner or operator will place signage on-site by October 1, 2021 indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4.c.

TABLE 1*—Well Production Facilities

Total Historic Non-Emitting Facility Percent Production	May 1, 2022 Additional Required Non-Emitting Facility Percent Production	May 1, 2022 Maximum Required Non-Emitting Facility Percent Production	May 1, 2023 Additional Required Non-Emitting Facility Percent Production	May 1, 2023 Maximum Required Non-Emitting Facility Percent Production	Total Additional Required Non-Emitting Facility Percent Production By May 1 2023
> 75 %	+5%	90%	+10%	96.5%	+15%
> 60-75 %	+5%	80%	+10%	90%	+15%
> 40-60 %	+10%	65%	+15%	75%	+25%
> 20-40 %	+15%	50%	+20%	65%	+35%
0-20 %	+15%	35%	+25%	55%	+40%

* Table 1 establishes minimum increases in the percentage of liquids produced (based on historic non-emitting controller use) from non-emitting facilities. Owners or operators do not need to go beyond the maximum required percentages set forth in Table 1, although they may choose to do so.

III.C.4.d. Company-Wide Non-Emitting Controller Compliance Program for Natural Gas Compressor Stations that Commenced Operation Before May 1, 2021.

III.C.4.d.(i) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 2.

III.C.4.d.(ii) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must:

III.C.4.d.(ii)(A) Determine Total Controller Count for all controllers at all of the owner or operator's natural gas compressor stations that commenced operation before May 1, 2021. The Total Controller Count must include all pneumatic controllers and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.d.(ii)(B) Determine which controllers in the Total Controller Count are non-emitting and sum the total number of non-emitting controllers and designate those as Total Historic Non-Emitting Controllers.

III.C.4.d.(ii)(C) Determine the Total Historic Non-Emitting Percent Controllers by dividing the Total Historic Non-Emitting Controller Count by the Total Controller Count.

III.C.4.d.(iii) Owners or operators must demonstrate compliance with Table 2's May 1, 2022 and May 1, 2023 Additional Required Percentage of Non-Emitting Controllers through any combination of (1) retrofitting controllers at natural gas compressor stations to utilize non-emitting controllers or (2) permanently removing natural gas compressor stations from service.

III.C.4.d.(iv) Pneumatic controllers that emit natural gas to atmosphere at natural gas compressor stations with non-emitting controllers must be tagged, which will indicate that the controller may emit natural gas. The tags must differentiate between pneumatic controllers that are exempt under Sections IIII.C.4.e.(i)(A) through (C) and pneumatic controllers that emit natural gas to the atmosphere under the company-wide plan. Tagging pursuant to this Section III.C.4.d.(iv) must occur by May 1, 2022.

III.C.4.d.(v) If a natural gas compressor station for which the number of pneumatic controllers located at such compressor station was included in a calculation of achieving a Total Required Non-Emitting Percent Controllers target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgement or certification, within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2.

In each submission of the updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan, the owner or operator will provide the date (month and year) when the natural gas compressor station was transferred since the last submission and whether or not the compressor station contributed or will contribute towards achieving the Total Required Non-Emitting Percent Controllers. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Compressor Station Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Compressor Station Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.d.(vi) This section applies to owners or operators of natural gas compressor stations where all the owner or operator's active, operating natural gas compressor stations use only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers).

III.C.4.d.(vi)(A) No later than September 1, 2021, such owners or operators may file a one-time notification with the Division in lieu of the requirements in Sections III.C.4.d.(i) through (iii) that:

III.C.4.d.(vi)(A)(1) Lists each active, operating natural gas compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that, based on information and belief formed after reasonable inquiry, each of its active, operating natural gas compressor stations uses only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers); and

III.C.4.d.(vi)(A)(2) Lists each inactive, non-operating compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that after May 1, 2021, such compressor stations have not and subsequently will not operate with pneumatic controllers that emit natural gas to the atmosphere, except pneumatic controllers that qualify for exclusions set forth in subject to Sections III.C.4.e.(i)(A) through (C).

III.C.4.d.(vi)(B) If applicable, the notifications submitted under this section must list any pneumatic controllers that qualify for exclusions pursuant to Sections III.C.4.e.(i)(A) through (C) and identify the specific exemption applicable to each such pneumatic controller. Operators must tag any controller qualifying for the exclusions in Sections III.C.4.e.(i)(A) through (C) by October 1, 2021.

III.C.4.d.(vi)(C) The owner or operator must maintain a copy of the one-time notification required by Section III.C.4.d.(vi)(A) for five years.

TABLE 2* – Natural Gas Compressor Stations					
Total Historic Percentage of Non-Emitting Controllers	**May 1, 2022 Additional Required Percentage of Non-Emitting Controllers**	**May 1, 2022 Maximum Required Percentage of Non-Emitting Controllers**	**May 1, 2023 Additional Required Percentage of Non-Emitting Controllers**	**May 1, 2023 Maximum Required Percentage of Non-Emitting Controllers**	**Total Additional Required Percentage of Non-Emitting Controllers By May 1, 2023**
> 75 %	+10%	90%	+15%	100%	+25%
>60-75 %	+10%	85%	+20%	92%	+30%
>40-60 %	+10%	70%	+25%	75%	+35%
>20-40 %	+15%	50%	+25%	65%	+40%
0-20 %	+20%	35%	+25%	60%	+45%

* Table 2 establishes minimum additional percentages of non-emitting controllers required by May 1, 2022 and May 1, 2023 based on a company's historic percentage of non-emitting controllers. Owners and operators need not go beyond the maximum required percentages specified in Table 2, although they may choose to do so.

III.C.4.e. Pneumatic Controllers That Emit Natural Gas to the Atmosphere Not Subject to Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations.

III.C.4.e.(i) Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements in Section III.C.4.a. and are not required to be retrofit in order to count the facility or controller as non-emitting for compliance with the company-wide plans under Sections III.C.4.c. and III.C.4.d.

III.C.4.e.(i)(A) Pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.

III.C.4.e.(i)(A)(1) Owners or operators that seek to rely on this exemption for facilities listed in Sections III.C.4.a.(i) through (iii) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to installation of emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(A)(2) Owners or operators that seek to rely on this exemption to maintain emitting controllers at facilities that are retrofit to meet requirements of Section III.C.4.c.(i) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(B) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.

III.C.4.e.(i)(C) Pneumatic controllers that emit natural gas located on temporary or portable equipment meeting the requirements of this Section III.C.4.e.(i)(C).

III.C.4.e.(i)(C)(1) Upon notice to the Division on a form developed by the Division, pneumatic controllers that emit natural gas other than those covered by Section III.C.4.e.(i)(B) located on temporary or portable equipment that is in use and onsite for sixty (60) days or less. However, this exemption for temporary or portable equipment does not apply to pneumatic controllers that emit natural gas used on temporary or portable equipment to temporarily increase throughput capacity of a facility.

III.C.4.e.(i)(C)(2) An owner or operator must obtain written approval from the Division for continued use beyond 60 days of pneumatic controllers that emit natural gas under Section III.C.4.e.(i)(C). The owner or operator must submit the request for an extension to the Division at least fourteen (14) days before the 60-day period expires. If the Division does not respond to the request before the 60-day period expires, the request will be deemed approved until such time as the Division may determine that the extension should be denied.

III.C.4.e.(i)(C)(2)(a) To request such an exemption, the owner or operator must submit a plan for Division approval which (1) identifies the temporary or portable equipment and number and type of pneumatic controllers that emit natural gas, (2) identifies how long the owner or operator plans to keep the equipment on site, (3) explains the need for an extension, and (4) other information as reasonably required by the Division.

III.C.4.e.(i)(C)(2)(b) In explaining the need for an extension, the operator must clearly identify the basis for extension; the anticipated schedule for use of the temporary or portable equipment; and the steps taken to minimize the length of the requested extension.

III.C.4.e.(i)(C)(3) The operator must inspect the pneumatic controllers using approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the associated well production facility or compressor station, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9.

III.C.4.e.(i)(D) Pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices and for artificial lift control located on a wellhead: (1) greater than one quarter mile from the associated production facilities for well production facilities that commenced operation on or after May 1, 2021; or (2) not located on the same surface disturbance as the associated production facilities for well production facilities that commenced operation before May 1, 2021.

III.C.4.e.(i)(D)(1) Owners or operators who seek to use a pneumatic controller at a qualifying wellhead at a facility listed in Sections III.C.4.a.(i) or (ii) that is not used as an emergency shutdown device or for artificial lift control must submit a justification for the use of such a pneumatic controller to the Division for approval forty-five (45) days prior to installation of the emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(D)(2) Owners or operators that seek to rely on this exemption to exclude emitting pneumatic controllers at a qualifying wellhead that are not used as an emergency shutdown device or for artificial lift control when determining their Total Historic Non-Emitting Facility Percent Production pursuant to Section III.C.4.c.(ii) must submit a justification to the Division for approval no later than July 1, 2021. If the Division does not respond to the justification by August 15, 2021, the justification will be deemed approved.

III.C.4.e.(i)(D)(3) Operators that utilize the exemption in Section III.C.4.e.(i)(D) must identify leaks from components using an approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the well production facility to which the well flows as set forth in Table 3 of Section II.E.4, or on a frequency no less than one time per year, whichever is greater, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9. For well production facilities that commenced operation before May 1, 2021 with wellheads utilizing this exemption, the requirement in this Section III.C.4.e.(i)(D)(3) must begin May 1, 2022.

III.C.4.e.(i)(D)(3)(a) An owner or operator that cannot reasonably access the wellhead site to conduct a monthly AIMM or AVO inspection due to circumstances beyond its control (including but not limited to the presence of crops, wildlife restrictions, or severe weather conditions) shall conduct an AVO or AIMM inspection, as applicable, within 14 days of the condition preventing inspection being resolved. Owners or operators that rely on this Section III.C.4.e.(i)(D)(3)(a) must maintain records pursuant to Section III.C.4.g.(vii) and report pursuant Section III.C.4.g.(viii).

III.C.4.e.(i)(D)(3)(b) Operators may use drone-mounted infra-red cameras that ensure line of sight and appropriate distance from the drone to all wellhead equipment and components to conduct the inspections required under Section III.C.4.e.(1)(D)(3). Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request.

III.C.4.e.(i)(D)(4) If a wellhead has on-site electrical grid power to operate an electric controller, then operators may not utilize the exemption in Section III.C.4.e.(i)(D) for any pneumatic controller at the wellhead for which it is technically feasible to utilize an electric controller.

III.C.4.e.(i)(D)(5) Operators may not utilize the exemption in Section III.C.4.e.(i)(D) where equipment with pneumatic controllers other than the wellhead is located at the wellhead site.

III.C.4.e.(ii) By October 1, 2021, each pneumatic controller at a well production facility that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) must be tagged, which will indicate that the controller may emit natural gas.

III.C.4.e.(iii) By October 1, 2021, each pneumatic controller at a natural gas compressor station that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (C) must be tagged, which will indicate that the controller may emit natural gas.

III.C.4.f. Company-Wide Well Production Facility and Natural Gas Compressor Station Reporting Requirements.

III.C.4.f.(i) Owners and operators of well production facilities subject to Sections III.C.4.c.(i) through (iii) must submit a Company-Wide Well Production Facility Pneumatic Controller Compliance Plan to the Division on the Division-approved form by September 1, 2021, and include all of the following elements:

III.C.4.f.(i)(A) A list of existing well production facilities as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(i)(B) The following for each well production facility:

III.C.4.f.(i)(B)(1) Historic Facility Production.

III.C.4.f.(i)(B)(2) Facility Percent Production.

III.C.4.f.(i)(B)(3) Historic Non-Emitting Facility Percent Production.

III.C.4.f.(i)(B)(4) The API number for each producing well included in the Total Historic Facility Production.

III.C.4.f.(i)(C) The following company-wide information:

III.C.4.f.(i)(C)(1) Total Historic Production.

III.C.4.f.(i)(C)(2) Total Historic Non-Emitting Facility Percent Production, including a list of facilities already using non-emitting controllers as determined in Section III.C.4.c.(ii)(E).

III.C.4.f.(i)(C)(3) Total Required Non-Emitting Facility Percent Production.

III.C.4.f.(i)(D) An indication of which and in what year well production facilities are expected to be retrofit with non-emitting controllers, or plugged and abandoned, to meet the required Additional Non-Emitting Facility Percent Production for each year listed in Table 1.

III.C.4.f.(ii) Owners or operators will submit an updated Company-Wide Facility Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 1, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Facility Percent Production in a previous year’s plan. The updated plan will include all of the following elements:

III.C.4.f.(ii)(A) All elements set forth in Sections III.C.4.f.(i)(A) through (C).

III.C.4.f.(ii)(B) The date (month and year) that any well production facilities were retrofit or plugged and abandoned since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(i)(D).

III.C.4.f.(ii)(C) An update of information set forth in Section III.C.4.f.(i)(D) if the Total Required Non-Emitting Facility Percent Production required by Table 1 has not been met.

III.C.4.f.(ii)(D) For each submission, the owner or operator must list each existing well production facility that is utilizing non-emitting controllers and provide a demonstration that the required Additional Non-Emitting Facility Percent Production for the relevant year has been met.

III.C.4.f.(ii)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Facility Percent Production has been met.

III.C.4.f.(iii) Owners and operators of natural gas compressor stations subject to Sections III.C.4.d.(i) through (iii) must submit a Company-Wide Compressor Station Pneumatic Controller Compliance Plan to the Division on a Division-approved form by September 1, 2021, and include all of the following elements:

III.C.4.f.(iii)(A) A listing of existing natural gas compressor stations as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(iii)(B) The following company-wide information:

III.C.4.f.(iii)(B)(1) Total Controller Count, including a list of each pneumatic controller and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.f.(iii)(B)(2) Total Historic Non-Emitting Controllers, including an indication as to which controllers are already non-emitting.

III.C.4.f.(iii)(B)(3) Total Required Non-Emitting Facility Percent Controllers.

III.C.4.f.(iii)(C) An indication of which and in what year controllers are expected to be retrofit with non-emitting controllers or removed from service (as applicable) to meet the required Additional Non-Emitting Percent Controllers for each year listed in Table 2.

III.C.4.f.(iv) Owners or operators will submit an updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 2, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Percent Controllers in a previous year's plan. The updated plan will include all of the following elements:

III.C.4.f.(iv)(A) All elements set forth in Sections III.C.4.f.(iii)(A) through (B).

III.C.4.f.(iv)(B) The date (month and year) that any controllers at natural gas compressor stations were retrofit or removed from service since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(iii)(C).

III.C.4.f.(iv)(C) The information set forth in Section III.C.4.f.(iii)(C) if the Total Required Non-Emitting Percent Controllers required by Table 2 has not been met.

III.C.4.f.(iv)(D) For each submission, the owner or operator must list total controllers and total non-emitting controllers at existing natural gas compressor stations and provide a demonstration that the required Additional Non-Emitting Percent Controllers for the relevant year has been met.

III.C.4.f.(iv)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Percent Controller has been met.

III.C.4.g. Recordkeeping and Reporting Requirements. The records in Sections III.C.4.g.(i) through (vii) must be kept for a period of five years and made available to the Division upon request.

III.C.4.g.(i) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date natural gas compressor station pneumatic controllers were retrofit or is taken out of service.

III.C.4.g.(ii) If claiming an exemption under Sections III.C.4.e.(i)(A) – (D), records for each pneumatic controller demonstrating that the exemption applies.

III.C.4.g.(iii) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans required to be submitted by Sections III.C.4.f.(i) – (iv).

III.C.4.g.(iv) For any owner or operator utilizing the provision in Section III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies for that provision.

III.C.4.g.(v) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

III.C.4.g.(vi) Records required to be submitted to the Division pursuant to Sections III.C.4.c.(v) and III.C.4.d.(v).

III.C.4.g.(vii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) must maintain: (1) the date of the AIMM or AVO inspection at the production facility to which the well flows, (2) the date of the AIMM or AVO inspection of the wellhead site once the conditions preventing inspection has been resolved, and (3) records demonstrating the circumstances that prevented the wellhead site from being inspected.

III.C.4.g.(viii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) shall report annually by May 31 of each year, on a form approved by the Division, the number of wellhead sites for which the AIMM inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), the number of wellhead sites for which the AVO inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), and the total number of wellhead sites where inspections were delayed pursuant to Section III.C.4.e.(i)(D)(3)(a) for (1) 30 days or less, (2) greater than 30 days but less than or equal to 90 days, and (3) greater than 90 days.

III.D. Monitoring

This section applies to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

III.D.1. In the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.1.b. Effective May 1, 2009, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band, eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.2. In the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.D.2.a. Effective May 1, 2018, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.2.b. Effective May 1, 2018, the owner or operator must inspect each pneumatic controller with a natural gas bleed rate greater than zero on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.3. (State Only) Statewide:

III.D.3.a. Effective May 1, 2015, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.3.b. Effective May 1, 2015, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.E. Recordkeeping

III.E.1. In the 8-Hour Ozone Control Area:

III.E.1.a. Continuous bleed, natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.E.1.a.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.

III.E.1.a.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour. Owners or operators must use this information to update the estimate required in Section III.E.1.a.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

III.E.1.b. Continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant:

III.E.1.b.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero.

III.E.1.b.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero. Owners or operators must use this information to update the estimate required in Section III.E.1.b.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

III.E.1.c. Records must be maintained for a minimum of five years and made available to the Division upon request.

III.E.2. This section applies only to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

III.E.2.a. The owner or operator must maintain a log of the total number of pneumatic controllers and their associated controller numbers per facility, the total number of pneumatic controllers per company and the associated justification that the pneumatic controllers must be used pursuant to Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.). The log shall be updated on a monthly basis.

III.E.2.b. The owner or operator must maintain a log of necessary maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

III.E.2.c. Records of maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

III.F. (State Only) Pneumatic Controller Inspection and Enhanced Response

III.F.1. General Requirements

III.F.1.a. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.1.b. Beginning May 1, 2020, owners or operators of natural gas-driven pneumatic controllers state-wide must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.2. Pneumatic controller inspection

III.F.2.a. Beginning June 30, 2018, through calendar year 2019, owners or operators of natural gas-driven pneumatic controllers at well production facilities in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.a.(i) Annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total.

III.F.2.a.(ii) Semi-annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.a.(iii) Quarterly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.b.(i) Annually at well production facilities in the 8-Hour Ozone Control Area with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than two (2) tons per year, based on a rolling twelve-month total.

III.F.2.b.(ii) Semi-annually at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than or equal to two (2) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.b.(iii) Quarterly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b.(iv) Monthly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.c. For purposes of Sections III.F.2.a. and III.F.2.b., the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

III.F.2.d. Beginning June 30, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.d.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.d.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations outside the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.e.(i) Semi-annually at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.e.(ii) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than twelve (12) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.f. For purposes of Sections III.F.2.d. and III.F.2.e., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

III.F.2.g. Where detectable emissions from the pneumatic controller are observed, owners or operators must determine whether the pneumatic controller is operating properly within five (5) working days after detecting emissions. In making this determination, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.2.h. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced response or follow manufacturer specifications to return the pneumatic controller to proper operation.

III.F.3. Enhanced response and remonitoring

III.F.3.a. Enhanced response must begin no later than five (5) working days and the pneumatic controller returned to proper operation no later than thirty (30) working days after determining the pneumatic controller is not operating properly, unless parts are unavailable, the equipment requires shutdown to complete enhanced response, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced response conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced response must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced response must be completed within fifteen (15) working days after the cause of delay ceases to exist.

III.F.3.b. Within fifteen (15) working days of completion of enhanced response, the owner or operator must verify the pneumatic controller is operating properly. In verifying proper operation, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.3.c. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Division unless the owner or operator fails to determine whether the pneumatic controller is operating properly in accordance with Section III.F.2., perform any necessary enhanced response in accordance with Section III.F.3., keep records in accordance with Section III.F.4., or submit reports in accordance with Section III.F.5.

III.F.4. Owners or operators must maintain the following records for a minimum of three (3) years and make records available to the Division upon request.

III.F.4.a. The date, facility name, facility AIRS ID or facility location if the facility does not have an AIRS ID, and approved instrument monitoring method used for each inspection;

III.F.4.b. A list of pneumatic controllers, including type, determined to be not operating properly;

III.F.4.c. For intermittent pneumatic controllers observed to have detectable emissions but determined to be operating properly, a brief explanation of the basis for concluding that the intermittent pneumatic controller was operating properly. The explanation can include, but is not limited to, an owner or operator's standard operating procedure detailing how to determine whether an intermittent pneumatic controller is operating properly, or an individual explanation;

III.F.4.d. The date(s) of enhanced response and a description of the actions taken to return the pneumatic controller to proper operation;

III.F.4.e. The date the owner or operator verified the pneumatic controller was returned to proper operation; and

III.F.4.f. The delayed repair list, including the date and duration of any period where the enhanced response was delayed beyond thirty (30) days after determining the pneumatic controller is not operating properly due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for returning the pneumatic controller to proper operation. Delay of enhanced response due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for pneumatic controller inspection and enhanced response compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

III.F.5. Owners or operators of pneumatic controllers at well production facilities or natural gas compressor stations must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019 for facilities in the 8-Hour Ozone Control Area and May 31st, 2021, for facilities outside the 8-Hour Ozone Control Area) that includes, at a minimum, the following information regarding pneumatic controller inspection and enhanced response activities at their subject facilities conducted the previous calendar year:

III.F.5.a. The total number and type of pneumatic controllers returned to proper operation, the types of actions taken to return the pneumatic controllers to proper operation, and the facility type (by inspection frequency tier of well production facility or natural gas compressor station);

III.F.5.b. The number and type of pneumatic controllers on the delayed repair list as of December 31st broken out by the facility type (by inspection frequency tier of well production facility or natural gas compressor station), and the basis for each delay; and

III.F.5.c. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year.

III.F.6. The provisions in Section III.F. will be reassessed by the Division and stakeholders in 2020.

IV. (State Only) Control of Emissions from the Natural Gas Transmission and Storage Segment

IV.A. Definitions

IV.A.1. “Best management practice” (BMP) means a demonstrated and commercially available or innovative emission-reducing technology or work practice.

IV.A.2. “Best management practices plan” (BMP plan) means a written plan that includes, but is not limited to, each natural gas transmission and storage segment owner or operator’s planned and implemented BMPs to reduce methane emissions from its facilities within the natural gas transmission and storage segment.

IV.A.3. “Natural gas transmission and storage segment” (segment) includes onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015), that are physically located in Colorado.

IV.A.4. “Natural gas transmission and storage segment Colorado throughput” (segment throughput) means the total volume of natural gas, as adjusted for methane, transported through transmission pipelines in Colorado as reported to the Department of Energy’s (DOE) Energy Information Administration (EIA) for Form 176, excluding net volumes stored as liquefied natural gas or in underground storage facilities.

IV.A.5. “Natural gas transmission and storage segment emissions inventory protocol” (inventory protocol) means the requirements by which natural gas transmission and storage segment owners or operators will quantify and report methane, ethane, carbon monoxide (CO), carbon dioxide (CO2), nitrous oxide (N2O), nitrogen oxides (NOx), and volatile organic compound (VOC) emissions. The protocol will specify the segment facilities and types of activity data collected, emissions quantification methodologies, throughput calculation methodologies, criteria for determining whether events are beyond the control of the owner or operator, and the process for designating and protecting confidential business information (CBI), consistent with Colorado law.

IV.A.6. “Performance-based program” means a program of BMPs implemented and documented by each natural gas transmission and storage segment owner or operator to reduce methane emissions in order to achieve the system-wide emissions intensity target.

IV.A.7. “Steering committee” means five members approved by the Division to serve as a technical working group for developing program guidance documents and evaluating progress against the system-wide emissions intensity target. The committee members will include two representatives from natural gas transmission and storage segment owners or operators (or industry trade organizations representing owners or operators), two members representing the general public (including but not limited to environmental organizations, local government groups, or citizens), and one Division member.

IV.A.8. “Segment-wide emissions intensity” means the natural gas transmission and storage segment methane emissions divided by the natural gas transmission and storage segment throughput.

IV.A.9. “Segment-wide emissions intensity target” (segment-wide target) means the target established by the steering committee reflected as annual segment-wide methane emissions from Colorado’s natural gas transmission and storage segment divided by the annual natural gas transmission and storage segment Colorado throughput.

IV.B. Beginning January 1, 2020, each segment owner or operator must participate in this performance based program to reduce segment-wide methane emissions.

IV.B.1. By April 1, 2020, a steering committee charter and the steering committee members will be approved by the Division.

IV.B.2. By September 30, 2020, the Division will publish the inventory protocol and any associated program guidance documents developed by the steering committee.

IV.B.3. By December 31, 2020, each segment owner or operator must develop a company-specific BMP plan. The BMP plan must contain each element from the BMP plan template chapter of the program guidance document, which will include, but is not limited to, a list of information the owner or operator must collect to demonstrate the BMPs performed. By December 31st of each year (beginning December 31st, 2021), each owner or operator must review and update, as appropriate, its company-specific BMP plan and document in the BMP plan any changes.

IV.B.4. Beginning January 1, 2021, each segment owner or operator will

IV.B.4.a. Implement company specific BMP plans.

IV.B.4.b. Collect emissions inventory data in accordance with the inventory protocol and its company-specific BMP plan.

IV.B.5. By May 1, 2022, the segment owners or operators will select a third-party contractor from a pool of qualified applicants to receive, safeguard, and aggregate company-specific reports as described in Sections IV.D.3. and IV.D.4. The steering committee will establish criteria for the selection of the third-party contractor. The segment owners and operators will use a competitive bidding process to solicit applications from contractors who meet the criteria and will provide an opportunity for the steering committee to reject unqualified applicants.

IV.B.6. By October 1, 2023, the steering committee will determine the segment-wide emissions intensity target using the 2021 and 2022 emissions inventory data. In developing the initial or updated segment-wide emissions intensity target and evaluating the program, the steering committee may request non-company specific information from the Division (in accordance with the Colorado Opens Record Act) or the third-party contractor to assist in setting such target or such evaluation. The steering committee may ask companies to explain emission factors and methodologies used to calculate or measure emissions.

IV.C. The segment-wide emissions intensity target must first be achieved by January 1, 2025, based on the 2024 reporting year.

IV.C.1. By October 1 of each year (beginning October 1, 2025), the steering committee will submit a compliance certification to the Division that the segment achieved the segment-wide emissions intensity target for the prior calendar year.

IV.C.2. If the steering committee cannot certify compliance with the segment-wide emissions intensity target, the steering committee will develop a plan (which may include amendments to program guidance documents) and timeline for the segment to achieve compliance with the segment-wide emissions intensity target.

IV.C.3. Beginning January 1, 2026, and every three (3) years thereafter if appropriate, the steering committee will assess the segment-wide emissions intensity target for continual improvement.

IV.D. Recordkeeping and reporting

IV.D.1. The Division will provide an update on the development of this program and initial implementation efforts to the Air Quality Control Commission during a scheduled Commission meeting on or after January 2021.

IV.D.2. Segment owners or operators must maintain BMP plans and emissions inventory reports for a period of five (5) years and make records available to the Division upon request.

IV.D.3. By June 30 of each year (beginning June 30, 2022), owners or operators of the natural gas transmission and storage segment will submit company-wide reports to the third-party contractor.

IV.D.3.a. Emissions claimed to be beyond the control of the owner or operator, using the criteria and methods established by the steering committee, must be included in the company-wide report but will not be used to set or determine compliance with the segment-wide emissions intensity target.

IV.D.3.b. Emissions and emission reductions associated with any requirements of the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Colorado Public Utilities Commission (CPUC), and/or the Federal Energy Regulatory Commission (FERC) must be included in the report and used for purposes of calculating compliance with the system-wide emissions intensity target, unless they qualify under Section IV.D.3.a., but this Section IV. does not supersede or alter these agencies applicable regulations or requirements.

IV.D.4. The third-party contractor must aggregate the company-wide reports into a segment-wide report and provide it to the steering committee by August 15 of each year (beginning August 15, 2022) on a form developed by the steering committee and approved by the Division. The segment-wide report must include, at a minimum

IV.D.4.a. The segment-wide emissions, apportioned by county,

IV.D.4.b. A report of the numbers and types of events subject to Section IV.D.3.a. and the segment-wide emissions resulting from each type of event.

IV.D.4.c. The BMPs implemented to mitigate or avoid emissions and a description of how the BMPs mitigate, reduce, and/or avoid emissions.

IV.D.4.d. The segment-wide segment throughput.

IV.D.4.e. The segment-wide emissions intensity. If the steering committee determines that one or more types of events reported under Section IV.D.4.b. were not beyond the control of the owner or operator, the steering committee will revise the segment-wide emissions intensity calculation to include the methane emissions from those events.

IV.D.5. Segment owners or operators must submit an annual certification to the Division by June 30 of each year (beginning June 30, 2021) that includes

IV.D.5.a. A certification that the company-specific BMP plan was developed or reviewed in accordance with Section IV.B.3.

IV.D.5.b. A certification that the company-wide report was submitted to the third-party contractor in accordance with Section IV.D.3.

IV.D.5.c. Beginning in 2022, a certification of company BMP plan compliance in accordance with Section IV.B.4., including

IV.D.5.c.(i) The company's implementation of the BMPs in the company-specific BMP plan.

IV.D.5.c.(ii) Instances of non-conformance with the company-specific BMP plan, reason(s) for non-conformance, and any modifications of the applicable element(s) of the BMP plan.

IV.D.5.c.(iii) Any use of alternative emission reduction approaches not specified in the company-specific BMP plan.

IV.D.5.d. With each submission under Sections IV.D.5.a. through IV.D.5.c., a certification by a responsible official that, based on information and belief after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IV.D.6. The Division may provide an update briefing to the Air Quality Control Commission during a scheduled Commission meeting on or after October 1 of each year (beginning October 1, 2022). The update briefing will include any assessment of the segment-wide target, as specified in Section IV.C.3.

V. (State Only) Oil and Natural Gas Operations Emissions Inventory

V.A. Applicability

V.A.1. On or before June 30th, 2021 (and on June 30th each year thereafter), the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.A.2. On or before June 30th, 2022 (and on June 30th each year thereafter), the owner or operator or class II disposal well facilities that are not subject to reporting under Section IV. must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.B. General reporting requirements

V.B.1. The following information must be reported in accordance with Section V.A.

V.B.1.a. Company name, physical street address, and name and contact information of the company representative, for reporting purposes.

V.B.1.b. The date of submittal and the year covered by the report.

V.B.1.c. A list of the activities or equipment, as specified in Section V.C., for which emissions are reported.

V.B.1.d. The company's monthly actual emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), nitrous oxide (N2O), carbon dioxide (CO2), carbon monoxide (CO), methane, and ethane for each month of May through September.

V.B.1.e. The company's annual actual emissions of VOCs, NOx, N2O, CO2, CO, methane, and ethane for the entire calendar year.

V.B.1.f. The actual emissions of VOCs, NOx, N2), CO2, CO, methane, and ethane for each activity or equipment listed in Section V.C. per facility, or per pipeline between facilities where the pipeline is not located at a stationary source.

V.B.1.f.(i) The report must include the actual emissions from each activity or equipment per month for each month of May through September.

V.B.1.f.(ii) The report must include the actual emissions from each activity or equipment for the entire calendar year.

V.B.1.g. A certification by the company representative that supervised the development and submission of the inventory report that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

V.B.2. The owner or operator must submit a revised annual report after discovering that an annual report submitted within the previous two (2) years contained one or more substantive errors. A substantive error is a mass of emissions of any individual pollutant subject to reporting under Section V. that is at least 10% higher or lower than the mass of emissions of the pollutant reported across the owner or operator's activity or equipment, as listed in Section V.C., in Colorado. A refinement of or improvement to an emissions estimation technique or emission factor is not a substantive error but must be noted in the subsequent annual report after the refinement or improvement. Revised annual reports must be submitted by August 31 if the substantive error is discovered between January 1 and June 30, and by February 28 if the substantive error is discovered between July 1 and December 31 of the preceding calendar year.

V.C. Beginning July 1, 2020, and each calendar year thereafter, owners or operators must maintain the following information for inclusion in the annual report, except that beginning January 1, 2021, owners or operators must maintain the information described in Sections V.C.2.g. and V.C.2.h. Beginning May 1, 2021, owners or operators of class II disposal well facilities must maintain the following information for inclusion in the annual report.

V.C.1. AIRS number of the activity or equipment and associated facility or pipeline (if a pipeline between facilities) location, including latitude and longitude coordinates. If the activity or equipment does not have an AIRS number, a description of the activity or equipment.

V.C.2. Actual emissions from each activity or equipment listed below, unless otherwise specified in the Division-approved report format, and the emission factor(s), assumptions, and calculation methodology used to calculate the emissions.

V.C.2.a. Abnormal events, except those reported as malfunctions under the Common Provisions or in another activity or equipment.

V.C.2.b. Acid gas removal units.

V.C.2.c. Associated gas venting and flaring, aggregated per facility.

V.C.2.d. Blowdowns from facility equipment piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet, aggregated per activity below per facility.

V.C.2.d.(i) Pipeline venting within the facility boundary.

V.C.2.d.(ii) Compressors.

V.C.2.d.(iii) Scrubbers/strainers.

V.C.2.d.(iv) Pig launchers and receivers.

V.C.2.d.(v) Emergency shutdowns (regardless of equipment type).

V.C.2.d.(vi) All other equipment (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) with a physical volume between isolation valves greater than or equal to 50 cubic feet.

V.C.2.e. Boilers.

V.C.2.f. Centrifugal compressor leaks or vents, aggregated per facility.

V.C.2.g. Class II disposal well facility fluids accepted for injection. Owners or operators will take periodic, representative samples of the liquids for estimating emissions for the annual report.

V.C.2.h. Class II disposal well facility produced water ponds.

V.C.2.i. Drilling mud and mud pits.

V.C.2.j. Flares and enclosed combustion devices, where not otherwise reported in the emissions of another emissions source category.

V.C.2.k. Fugitive emissions from components, aggregated per facility.

V.C.2.l. Hydrocarbon liquid storage tanks.

V.C.2.m. Hydrocarbon liquid loadout.

V.C.2.n. Maintenance and safety, where not otherwise reported in the emissions of another emissions source category.

V.C.2.o. Natural gas dehydration (glycol and desiccant).

V.C.2.p. Natural gas pneumatic controllers, aggregated per facility.

V.C.2.q. Natural gas pneumatic pumps, aggregated per facility.

V.C.2.r. Non-road internal combustion engines.

V.C.2.s. Pipeline segments between facilities.

V.C.2.t. Process heaters.

V.C.2.u. Produced water storage tanks.

V.C.2.v. Produced water loadout.

V.C.2.w. Reciprocating compressor leaks or vents, aggregated per facility.

V.C.2.x. Separators (e.g., two-phase separators, three-phase separators, high/low pressure separators, heater-treaters, vapor recovery towers, etc.).

V.C.2.y. Stationary combustion turbines.

V.C.2.z. Stationary compression ignition internal combustion engines.

V.C.2.aa. Stationary spark ignition internal combustion engines.

V.C.2.bb. Temporary completion and/or workover equipment (e.g., tanks).

V.C.2.cc. Thermal oxidizing units, where not otherwise reported in the emissions of another emissions source category.

V.C.2.dd. Well completions (includes flowback).

V.C.2.ee. Well workovers.

V.C.2.ff. Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

VI.A. Definitions

VI.A.1. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

VI.A.2. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.

VI.A.3. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

VI.A.4. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

VI.A.5. “Flowback vessel” means a vessel that contains flowback.

VI.A.6. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

VI.A.7. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

VI.A.8. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

VI.A.9. “Tank measurement system” means equipment and methods used to determine the quantity of the liquids inside a flowback vessel without requiring direct access through the flowback vessel thief hatch or other opening.

VI.A.10. “Well” means a hole drilled for the purpose of producing oil and/or natural gas.

VI.A.11. “Well completion” means the process that allows for the flow of petroleum and/or natural gas from newly drilled wells, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic fracturing, drill-out, flowback).

VI.A.12. “Well re-completion” means the process that allows for the flow of petroleum and/or natural gas from an existing well from any geological interval not currently producing in the existing well, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic re-fracturing, drill-out, flowback).

VI.B. General provisions

VI.B.1. At all times the facility and equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions.

VI.B.2. Air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable and consistent with technological limitations and good engineering and maintenance practices.

VI.C. Air quality monitoring

VI.C.1. Owners or operators of drilling operations that begin on or after May 1, 2021, must monitor air quality at and/or around the pre-production and early production operations.

VI.C.1.a. Owners or operators must monitor air quality for at least ten (10) days prior to beginning pre-production operations, during all pre-production operations, and for at least six months after the well is capable of consistently producing either separable gas or salable liquid hydrocarbons (i.e., early production).

VI.C.1.b. Owners or operators must submit an air quality monitoring plan to the Division and the local government with jurisdiction over the location of the operations and any other local government unit, where applicable, within 2,000 feet of the proposed operations at least sixty (60) days prior to beginning air quality monitoring. Upon the request of any of these local government units within 14 days of receiving the plan, the Division will consult with them as part of its review process. Owners or operators must receive approval from the Division of the air quality monitoring plan prior to beginning air quality monitoring. Owners or operators must comply with the plan once approved. The air quality monitoring plan must include, at a minimum:

VI.C.1.b.(i) The owner or operator name and the contact information of the owner or operator representative for monitoring purposes.

VI.C.1.b.(ii) The planned schedule for drilling and pre-production operations.

VI.C.1.b.(iii) The operations to be monitored including the API number of the well(s), location of the operations including latitude and longitude coordinates, and any associated facility or equipment AIRS number(s).

VI.C.1.b.(iv) Whether the local government with jurisdiction over the location of the operations has air quality monitoring requirements applicable to pre-production and/or early production operations, a description of those requirements, and a local government contact for air quality monitoring purposes.

VI.C.1.b.(v) The monitoring objective(s), which must include one or more of the following (and may include additional objectives such as field-testing new air quality monitoring technologies or improving emissions inventories):

VI.C.1.b.(v)(A) Detect, evaluate, and reduce as necessary hazardous air pollutant emissions;

VI.C.1.b.(v)(B) Detect, evaluate, and reduce as necessary ozone precursor emissions;

VI.C.1.b.(v)(C) Detect, evaluate, and reduce as necessary methane emissions.

VI.C.1.b.(vi) The air pollutant(s) and other parameters to be monitored. Pollutants must include at least one of the following: total VOCs, methane, benzene or BTEX (benzene, toluene, ethyl benzene and xylenes) or other indicator of hydrocarbon emissions from pre-production and early production operations, as appropriate to meeting the specified monitoring objectives.

VI.C.1.b.(vii) A description of the monitoring equipment to be deployed, including the manufacturer and model information and any manufacturer specifications for the monitoring equipment and data systems. The description of pollutant monitoring equipment should explain why it was chosen and document or provide references describing relevant prior use and evaluations that are known to the owner or operator.

VI.C.1.b.(viii) A description of the meteorological monitoring equipment to be deployed. If meteorological data will not be collected on-site, the plan must provide reasoning and justification, and identify the meteorological station from which data will be obtained and demonstrate that the station represents conditions at the oil and gas development site.

VI.C.1.b.(ix) A monitor siting plan, which must include but is not limited to:

VI.C.1.b.(ix)(A) The number of monitors and/or sensors to be deployed.

VI.C.1.b.(ix)(B) The location and height of the monitoring equipment, including for each phase of operations if location and height of the equipment will change (e.g., monitoring placement impacted by sound walls).

VI.C.1.b.(ix)(C) A topographic map and plan of the site, showing the expected equipment layout, including air quality and meteorological monitor locations and their distance from pre-production and production operations. The map must indicate any obstructions to air flow to the monitor(s) and also show all roads and access ways within a half-mile of the facility and any contiguous structures, whether or not they are part of the production operations.

VI.C.1.b.(ix)(D) A description of how the placement of monitoring equipment minimizes surface disturbances, in alignment with the Colorado Oil and Gas Conservation Commission's site preparation requirements.

VI.C.1.b.(ix)(E) An explanation of how the number and placement of monitoring equipment will be adequate to achieve the desired air quality monitoring objectives, considering the monitoring equipment's detection limit and other limitations.

VI.C.1.b.(x) The standard operating procedures that will be employed, to include at minimum:

VI.C.1.b.(x)(A) The sampling and/or measurement interval, averaging times, minimum detection concentration or level, expected precision, and confidence level at which pollutant data will be reported.

VI.C.1.b.(x)(B) The response level for each pollutant or indicator monitored and/or sampled and the response procedures or actions that will be taken if elevated levels are observed.

VI.C.1.b.(x)(C) The data quality indicators for precision and bias of the monitoring equipment.

VI.C.1.b.(x)(D) The quality control and quality assurance procedures, including calibration intervals and frequency, which will be used to ensure proper operation of the monitoring equipment. Owners or operators may reference and attach an existing methodology.

VI.C.1.b.(x)(E) A discussion of known limitations of the pollutant monitoring equipment and, if applicable, how they will be addressed.

VI.C.1.b.(x)(F) The protocol that will be used for acquiring, processing, and recording relevant meteorological data.

VI.C.1.b.(x)(G) The data system and operating protocol to be used for data collection, including, but not limited to, data logging, data processing, recording, downloading, backup and storage, and reporting.

VI.C.1.b.(x)(H) The methods for collecting and analyzing speciated or other samples of chemical constituents identified by the Division when indicated necessary based on site-specific concentration thresholds, if applicable.

VI.C.1.b.(xi) A description of how the monitoring equipment, pollutant(s) monitored, and siting plan are expected to detect elevated emissions and achieve at least one of the monitoring objectives listed in Section VI.C.1.b.(v).

VI.C.1.c. Within ten (10) days of approving a monitoring plan, the Division will notify all local government units identified in Section VI.C.1.b. of the plan approval.

VI.C.2. Recordkeeping and reporting

VI.C.2.a. Owners or operators must keep the following records for a minimum of three (3) years, unless otherwise specified, and upon request make records available to the Division. Local governments identified in Section VI.C.1.b may request those records from the Division. If the Division has not requested the records and a local government(s) identified in Section VI.C.1.b requests the records from the Division, the Division shall request the records from the owner or operator.

VI.C.2.a.(i) The air quality monitoring plan.

VI.C.2.a.(ii) Monthly reports and the data necessary to inform the monthly reports, as provided in Section VI.C.2.b.

VI.C.2.a.(iii) Activity logs to inform Section VI.C.2.b.(iii)(A) of the monthly report.

VI.C.2.a.(iv) For a period of one year after the monthly report, the underlying raw data associated with each monitor.

VI.C.2.a.(v) For a period of one year after the monthly report, the meteorological data in the time intervals as close to the sampling and/or measurement intervals as possible.

VI.C.2.b. Owners or operators must submit monthly reports of monitoring conducted to the Division by the last day of the month following the previous month of monitoring (e.g., by June 30 for the previous May 1-31), including

VI.C.2.b.(i) The month and year of the monitoring period.

VI.C.2.b.(ii) A description of the monitoring equipment and the pollutant(s) monitored.

VI.C.2.b.(iii) A description of the monitored operations including

VI.C.2.b.(iii)(A) The phase of operation (e.g., prior to pre-production, during pre-production operations, early production) and activities occurring during the monitored period.

VI.C.2.b.(iii)(B) API number of the well(s).

VI.C.2.b.(iii)(C) Location of the operations, including latitude and longitude coordinates.

VI.C.2.b.(iii)(D) Any associated facility or equipment AIRS number(s).

VI.C.2.b.(iii)(E) The date, time, and duration of any monitoring equipment downtime.

VI.c.2.b.(iii)(F) The date, time, and duration of operations malfunctions and shut-in periods or other events investigated for influence on monitoring.

VI.C.2.b.(iv) For the first monthly report after beginning monitoring during pre-production operations, a summary of air quality condition results monitored prior to beginning pre-production operations, including time series of the results at hourly or higher time resolution and a statistical summary of the air quality results monitored prior to beginning pre-production operations, including number of observations, maximum concentrations or levels, periodic averages, and data distributions including 5th, 25th, median, 75th and 95th percentile values.

VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5^{th}, 25^{th}, median, 75^{th} and 95 percentile values.

VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.

VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.

VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.

VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.

VI.C.2.b.(x) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.

VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).

VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.

VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.

VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.

VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

VI.D.2.a.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

VI.D.3. Recordkeeping

VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including

VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.

VI.D.3.a.(ii) The date and time of the onset of flowback.

VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.

VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.

VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

PART E Combustion Equipment and Major Source RACT

I. Control of Emissions from Engines

I.A Requirements for new and existing engines.

I.A.1. The owner or operator of any natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower commencing operations in the 8-hour Ozone Control Area on or after June 1, 2004 shall employ air pollution control technology to control emissions, as provided in Section I.B.

I.A.2. Any existing natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower, which existing engine was operating in the 8-hour Ozone Control Area prior to June 1, 2004, shall employ air pollution control technology on and after May 1, 2005, as provided in Section I.B.

I.A.3. Stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower are subject to Section I.D.5.

I.B. Air pollution control technology requirements

I.B.1. For rich burn reciprocating internal combustion engines, a non-selective catalyst reduction and an air fuel controller shall be required. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.B.2. For lean burn reciprocating internal combustion engines, an oxidation catalyst shall be required. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.B.3. The emission control equipment required by this Section I.B shall be appropriately sized for the engine and shall be operated and maintained according to manufacturer specifications.

I.C. The air pollution control technology requirements in Sections I.A. and I.B. do not apply to:

I.C.1. Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31.

I.C.2. Reciprocating internal combustion engines that the Division has determined will be permanently removed from service or replaced by electric units on or before May 1, 2007. The owner or operator of such an engine shall provide notice to the Division of such intent by May 1, 2005 and shall not operate the engine identified for removal or replacement in the 8-hour Ozone Control Area after May 1, 2007.

I.C.3. Any emergency power generator exempt from APEN requirements pursuant to Regulation Number 3, Part A.

I.C.4. Any lean burn reciprocating internal combustion engine operating in the 8-hour Ozone Control Area prior to June 1, 2004, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $5,000 per ton of VOC emission reduction. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by May 1, 2005. Any reciprocating internal combustion engine qualifying for this exemption shall not be moved to any other location within the 8-hour Ozone Control Area.

I.D. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

I.D.1. (State Only) Exemptions

I.D.1.a. The requirements of this Section I.D. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.1.b. Internal combustion engines that are subject to an emissions control requirement in a federally maximum achievable control technology (MACT) standard under 40 CFR Part 63, a Best Available Control Technology (BACT) limit, or a New Source Performance Standard (NSPS) under 40 CFR Part 60 are not subject to Section I.D.3.

I.D.2. (State Only) General Provisions

I.D.2.a. At all times, including periods of start-up and shutdown, engines and their associated equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

I.D.2.b. All engines and their associated equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file.

I.D.2.c. Any of the effective dates for installation of controls on internal combustion engines as required in Section I.D.3. may be extended at the Division's discretion for good cause shown.

I.D.3. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.3.a. Except as provided in Section I.D.3.b., the owner or operator of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in Table 1 shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section I.D.3.b. Table 1.

I.D.3.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥ 100 Hp and < 500 Hp	On or after January 1, 2008 On or after January 1, 2011	2.0 1.0	4.0 2.0	1.0 0.7
≥ 500 Hp	On or after July 1, 2007 On or after July 1, 2010	2.0 1.0	4.0 2.0	1.0 0.7

**These engines may also be subject to emission standards under Section I.D.5.*

I.D.4. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.4.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

I.D.4.a.(i) Except as provided in Sections I.D.4.a.(i)(B) and (C) and I.E.4.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.D.4.a.(i)(A) All control equipment required by this Section I.D.4.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

I.D.4.a.(i)(B) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63 (January 1, 2011), a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard under 40 CFR Part 60 (January 1, 2011) are not subject to this Section I.D.4.a.

I.D.4.a.(i)(C) The requirements of this Section I.D.4.a. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.4.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.4.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

I.D.4.b.(i) Except as provided in Section I.D.4.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.D.4.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.5. (State Only) Additional Requirements for Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.5.a. Applicability

I.D.5.a.(i) This Section I.D.5. applies to stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower.

I.D.5.a.(i)(A) For purposes of this Section I.D.5., modified means any physical change to the engine or change in method of operation that results in an increase in the emission rate of any air pollutant, and does not include any physical or operational changes excluded by 40 C.F.R. 60.14(e).

I.D.5.a.(i)(B) For purposes of this Section I.D.5., placed in service means the bringing of an engine on-site for use. The placed in service date is the date the engine begins to operate. The following is not considered placed in service: (1) moving an engine subject to an Alternative Company-Wide Compliance Plan to another site with the same owner or operator; (2) for engines in service on or before November 14, 2020, replacement under an authorized alternative operating scenario.

I.D.5.a.(i)(C) For purposes of this Section I.D.5., relocated means the bringing of an engine into the 8-Hour Ozone Control Area from outside the 8-Hour Ozone Control Area or the bringing of an engine into the State of Colorado from outside the State of Colorado. The relocation date is the date the subject engine begins to operate.

I.D.5.a.(ii) Exemptions.

I.D.5.a.(ii)(A) Engines that burn less than 100 MMBtu per year of natural gas on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.a.(ii)(B) Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31 are not subject to this Section I.D.5.

I.D.5.a.(ii)(C) Any emergency power generator exempt from APEN or construction permit requirements pursuant to Regulation Number 3, Parts A or B are not subject to this Section I.D.5.

I.D.5.a.(ii)(D) Emergency power generators that operate less than 250 hours per year on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.b. Emission Standards for Engines Subject to Section I.D.5.a.

I.D.5.b.(i) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine that is placed in service, modified, or relocated after November 14, 2020, must comply with the emission standards in Table 2 upon placement in service, modification, or relocation.

I.D.5.b.(ii) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine not subject to Section I.D.5.b.(i) must comply with the emission standards in Table 2 in accordance with the timing set forth Section I.D.5.b.(v).

TABLE 2			
Engine Type	Emission Standards (g/hp-hr)		
	NOx	CO	VOC
4-Stroke Lean Burn engines in service on or before November 14, 2020, (unless subject to a more stringent emission standard under Section I.D.3.b, above)	1.2	2.0	0.7
Rich Burn engines in service on or before November 14, 2020	0.8	2.0	0.7
4-Stroke Lean Burn engines placed in service, modified, or relocated after November 14, 2020	0.7	2.0	0.7
Rich Burn engines placed in service, modified, or relocated after November 14, 2020	0.5	2.0	0.7
2-Stroke Lean Burn engines	3.0	2.0	0.7

I.D.5.b.(iii) By May 1, 2021, owners and operators of an engine placed in service on or before November 14, 2020, that is subject to an emission standard in Table 2 must submit a notification to the Division containing the following information:

I.D.5.b.(iii)(A) The list of engines subject to an emission standard in Table 2, including AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), historical annual hours of operation averaged over calendar years 2017, 2018, and 2019, manufacturer model, serial number, horsepower, and engine configuration. The notification must also identify or calculate the g/hp-hr limit in an existing permit and the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the permitted rate. Engine configuration (e.g. rich burn or lean burn) for purposes of the emission standards in Table 2 is determined by the characterization on the engine's permit or APEN as of May 1, 2021. If the engine configuration is not identified in a permit or APEN, the owner or operator must submit an APEN with the current configuration information as determined by the owner or operator by May 1, 2021 to the Division.

I.D.5.b.(iii)(B) An identification of the applicable standard and a declaration as to whether each subject engine meets the applicable standard as of May 1, 2021. If an engine will meet the applicable standard through a permit modification only, as described in Section I.D.5.b.(iv)(A), below, the declaration should note the date of permit modification submittal.

I.D.5.b.(iii)(C) For all engines that do not meet the applicable emission standard as of May 1, 2021 or that cannot comply through a permit modification described in Section I.D.5.b.(iv)(A), below, a declaration of what action the owner or operator will take to meet the standard (e.g., control equipment installation, retrofit, replacement, electrification, shut-down). This declaration can be amended at any time prior to the applicable compliance date for that engine.

I.D.5.b.(iii)(D) The compliance deadline for each engine under Sections I.D.5.b.(i) or I.D.5.b.(v). An owner or operator may change a proposed compliance deadline for an engine subject to Section I.D.5.b.(v)(B) prior to that engine's compliance deadline, only after submittal of an updated notification to the Division that includes the updated compliance date and a demonstration that the requirements of Table 3 are met.

I.D.5.b.(iii)(E) Owners or operators that submit an Alternative Company-Wide Compliance Plan under Section I.D.5.c. are not subject to this Section I.D.5.b.(iii) for the emission standards in Table 2 for the engines covered by the Alternative Company-Wide Compliance Plan.

I.D.5.b.(iv) Permit Modification.

I.D.5.b.(iv)(A) An engine in service on or before November 14, 2020 that requires only a modification of an existing permit to meet the emission standards in this Section I.D.5.b. must submit a complete permit application containing the necessary limitations no later than May 1, 2021.

I.D.5.b.(iv)(B) For any engine not subject to Section I.D.5.b.(iv)(A), owners and operators must modify existing permits to reflect the emission standards or other operating conditions necessary to achieve compliance with Table 2. Complete permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.b.(iii)(D) above for that engine.

I.D.5.b.(v) Compliance Deadlines for engines subject to Section I.D.5.b.(ii).

I.D.5.b.(v)(A) Engines that comply with the emission standards on or before November 14, 2020, or are subject to Section I.D.5.b.(iv)(A) must meet the emission standards in Table 2 by May 1, 2022.

I.D.5.b.(v)(B) Engines not subject to Section I.D.5.b.(v)(A) must meet the emission standards in Table 2 in accordance with the timing set forth in Table 3.

TABLE 3

Location of Subject Engines by Owner or Operator	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of engines that must comply with Table 2 limits				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 34% of engines inside the 8-Hour Ozone Control Area	At least 67% of engines inside the 8-Hour Ozone Control Area; and at least 25% of engines outside the 8-Hour Ozone Control Area	100% of engines in the 8-Hour Ozone Control Area; and at least 50% of engines outside the 8-Hour Ozone Control Area	At least 75% of engines outside the 8-Hour Ozone Control Area	100% of all engines
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.b.(vi) If an owner or operator replaces an engine subject to an emission standard under this Section I.D.5.b. with a different stationary natural gas fired reciprocating internal combustion engine, the replacement engine must:

I.D.5.b.(vi)(A) if being placed under an alternative operating scenario pursuant to an existing Division issued permit, meet the same emission standard as the engine being replaced; or

I.D.5.b.(vi)(B) if the owner or operator of an engine chooses to comply via an Alternative Company-Wide Compliance Plan under Section I.D.5.c., meet an emission standard at least as stringent as the engine being replaced as provided for in the applicable Alternative Company-Wide Compliance Plan.

I.D.5.c. Alternative Company-Wide Compliance Plan.

I.D.5.c.(i) Owners and operators with five or more engines that are subject to Section I.D.5.b.(v)(B) may comply with the NOx requirements of Section I.D.5.b. through an Alternative Company-Wide Compliance Plan. Any owner or operator electing to develop an Alternative Company-Wide Compliance Plan must submit a Compliance Plan that meets the requirements of Section I.D.5.c.(ii) on or before May 1, 2021.

I.D.5.c.(i)(A) Only engines subject to an emission standard in Table 2 and that were placed in service on or before the November 14, 2020, can be included in an Alternative Company-Wide Compliance Plan submitted pursuant to this Section I.D.5.c.

I.D.5.c.(i)(B) Engines in an Alternative Company-Wide Compliance Plan must still meet the VOC and CO standards in Table 2 by the deadline established for that engine pursuant to Table 4.

I.D.5.c.(i)(C) Owners and operators owned by the same parent company may collectively submit a Compliance Plan in accordance with this Section I.D.5.c. However, the Compliance Plan must be signed and certified by a responsible official from each owner or operator with engines subject to the Compliance Plan acknowledging that each owner and operator is jointly and severally liable for compliance with the Compliance Plan and the provisions of this Section I.D.5.c. No engine may be included in multiple Alternative Company-Wide Compliance Plans.

I.D.5.c.(ii) The Compliance Plan must be submitted on the Division-approved form and include all of the following elements:

I.D.5.c.(ii)(A) A list of all of the engines that will rely on this Section I.D.5.c. to comply with the standards established in Section I.D.5.b. Each engine must be identified by AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), horsepower, manufacturer, model and serial number, historical annual operating hours (averaged over 2017, 2018, and 2019), and engine configuration.

I.D.5.c.(ii)(B) For each engine included in the Alternative Company-Wide Compliance Plan:

I.D.5.c.(ii)(B)(1) Identification of the most stringent NOx emission standard (in g/hp-hr or converted to g/hp-hr, if not expressed as such in the applicable permit) and operating conditions applicable to the engine under any rule or permit condition in effect on or before November 14, 2020.

I.D.5.c.(ii)(B)(2) Identification of the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the rate identified in Section I.D.5.c.(ii)(B)(1), above.

I.D.5.c.(ii)(B)(3) The emission standards (in g/hp-hr) and any operating conditions with which each engine will comply under the Alternate Company-Wide Compliance Plan, including any intended shut-downs, including any modifications or changes made to comply with the VOC or CO standards in Table 2.

I.D.5.c.(ii)(B)(4) The date by which each engine will meet the emission standards or other operating conditions identified in Section I.D.5.c.(ii)(B)(3) above, consistent with Table 4.

I.D.5.c.(ii)(B)(5) The maximum allowable NOx emissions (in tons/year) based on limits applicable on or before November 14, 2020, as identified in Section I.D.5.c.(ii)(B)(1).

I.D.5.c.(ii)(B)(6) The historic NOx emissions (in tons/year) averaged over calendar years 2017, 2018 and 2019, based on actual operating hours and permitted emission standards.

I.D.5.c.(ii)(B)(7) The NOx emissions that would be allowed on an annual basis (in tons/year) assuming the engine was complying with the emission standards established in Table 2.

I.D.5.c.(ii)(B)(8) Each engine's allowable NOx emissions (in tons/year) when operated in accordance with limitations identified in Section I.D.5.c.(ii)(B)(3), above, including any increase in NOx emissions that result from modifications or changes made to comply with the VOC or CO standards in Table 2.

I.D.5.c.(ii)(C) The total allowable NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(5).

I.D.5.c.(ii)(D) The total NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(6).

I.D.5.c.(ii)(E) The total NOx emissions calculated for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with the emission standards established in Table 2, as specified in Section I.D.5.c.(ii)(B)(7).

I.D.5.c.(ii)(F) The total allowable NOx emissions (in tons/year) calculated for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(8) above.

I.D.5.c.(ii)(G) A calculation of:

I.D.5.c.(ii)(G)(1) The difference between Section I.D.5.c.(ii)(C) and Section I.D.5.c.(ii)(F). This difference is called the “Plan Emission Reductions”.

I.D.5.c.(ii)(G)(2) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with Table 2, as specified in Section I.D.5.c.(ii)(E).

I.D.5.c.(ii)(G)(3) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(F).

I.D.5.c.(ii)(H) A demonstration that:

I.D.5.c.(ii)(H)(1) The total NOx emissions allowed under the Alternative Company-Wide Compliance Plan (Section I.D.5.c.(ii)(F)) are less than or equal to the total NOx emissions that would be allowed under Table 2 (Section I.D.5.c.(ii)(E)).

I.D.5.c.(ii)(H)(2) The reductions from emissions achieved by the Alternative Company-Wide Compliance Plan are greater than or equal to the reductions from actual emissions achieved by Table 2 (i.e. that the figure calculated in Section I.D.5.c.(ii)(G)(3) is greater than or equal to the figure calculated in Section I.D.5.c.(ii)(G)(2)).

I.D.5.c.(ii)(I) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the Compliance Plan are true, accurate, and complete.

I.D.5.c.(iii) Any owner or operator utilizing this Alternative Company-Wide Compliance Plan must meet the emission standards for NOx, CO and VOC as identified in I.D.5.c.(ii)(B)(3) by the compliance deadlines listed in Table 4, below.

I.D.5.c.(iv) Owners and operators must modify existing permits to reflect the emission standards or other operating conditions identified in the Compliance Plan (Section I.D.5.c.(ii)(B)(3)) for that engine. Permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.c.(ii)(B)(4) above for that engine.

I.D.5.c.(v) Compliance Plan Updates. By May 1st of each year (beginning in 2022) and continuing through and including the final year of a Compliance Plan, an owner or operator must submit an update to the Compliance Plan with the following information:

I.D.5.c.(v)(A) For each engine, any change in location and any action taken under the Compliance Plan (e.g., permit modification applied for, engine retrofit completed, engine taken offline) and the date;

I.D.5.c.(v)(B) A calculation of the percentage of Plan Emission Reductions achieved as of the date of submittal of the update (in each compliance period and cumulatively);

I.D.5.c.(v)(C) Any changes made to the Compliance Plan (e.g. change in compliance date for an engine). No change to the compliance date for an engine can be made after the date established in the Compliance Plan for that engine.;

I.D.5.c.(v)(D) If ownership or operation of an engine in the Compliance Plan for which emission reductions were included in the calculation of Plan Emission Reductions was sold or transferred in the previous year, an identification of how the owner or operator will achieve the portion of Plan Emission Reductions attributed to that engine under the Compliance Plan (the difference between Section I.D.5.c.(ii)(B)(5) and (8)).

I.D.5.c.(v)(E) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the update are true, accurate, and complete.

I.D.5.c.(vi) Nothing in this section I.D.5.c exempts an engine that is part of an Alternative Company-Wide Compliance Plan from compliance with the performance testing, monitoring, recordkeeping or reporting requirements of this Section I.D.5.

TABLE 4					
Location of Subject Engines covered by the Alternative Company-Wide Compliance Plan	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of Plan Emission Reductions Achieved				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 50% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 25% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 50% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100%of Plan Emission Reductions
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.d. Performance Testing

I.D.5.d.(i) Engines subject to this Section I.D.5. must conduct a performance test consistent with the requirements of this Section I.D.5.d.

I.D.5.d.(i)(A) The owner or operator of an engine subject to Section I.D.5.b.(ii) must conduct a performance test for NOx, CO, and O2 by May 1, 2021.

I.D.5.d.(i)(B) The owner or operator of an engine placed in service, modified, relocated or replaced after May 1, 2021 must conduct a performance test within 12 months of the date the engine is placed in service, modified, relocated or replaced.

I.D.5.d.(i)(C) The following engines are exempt from the requirements of this Section I.D.5.d.

I.D.5.d.(i)(C)(1) Engines subject to the performance testing requirements of 40 C.F.R. Part 60, Subpart JJJJ (July 1, 2019).

I.D.5.d.(i)(C)(2) Engines subject to at least semi-annual portable analyzer testing or ongoing performance testing in a permit issued on or before November 14, 2020.

I.D.5.d.(i)(D) A performance test conducted in accordance with 40 C.F.R. §60.4244 (July 1, 2019) between January 1, 2020 and May 1, 2021 will satisfy the initial performance testing requirements in Section I.D.5.d.(i)(A).

I.D.5.d.(ii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 C.F.R. Part 60, Appendix A (DATE), and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

I.D.5.d.(iii) Tuning of an engine prior to the performance test required by this Section I.D.5.d is not a violation of this rule. However, readjustment of an engine set point following the performance test that would negatively impact the performance of the engine (i.e. result in increased emissions above applicable permit limits) is a violation of this rule.

I.D.5.e. Monitoring. Except as provided in Section I.D.5.a.(ii), owners or operators of an engine subject to Section I.D.5.a must:

I.D.5.e.(i) Beginning on May 1, 2022, conduct semi-annual portable analyzer monitoring for NOx, CO, and O2. At least one calendar month must separate the semi-annual tests.

I.D.5.e.(i)(A) If the engine is operated for less than 200 hrs in any semi-annual period, then the portable analyzer monitoring need not occur during that semi-annual period (i.e. the engine does not need to be started for the sole purpose of portable monitoring).

I.D.5.e.(i)(B) All portable analyzer testing required by this section must be conducted using the Division's Portable Analyzer Monitoring Protocol (version: March 2006).

I.D.5.e.(i)(C) Tuning of an engine prior to semi-annual monitoring events required by this Section I.D.5.e.(i) is not a violation of this rule. However, readjustment of an engine set point following the monitoring event that would negatively impact the performance (i.e. result in increased emissions above applicable permit limits) of the engine is a violation of this rule.

I.D.5.e.(i)(D) A performance test conducted pursuant to Section I.D.5.d., 40 C.F.R. Part 60, JJJJ, or a permit requirement may take the place of the next required semi-annual portable analyzer test required by this section.

I.D.5.e.(i)(E) An engine subject to at least semi-annual portable analyzer testing requirements in an existing permit issued by the Division can comply with this Section I.D.5.e.(i) by complying with the testing requirements in the permit.

I.D.5.e.(ii) Beginning May 1, 2021, if a catalyst is used to reduce emissions:

I.D.5.e.(ii)(A) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within applicable limits.

I.D.5.e.(ii)(B) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop is greater than 2 inches outside the baseline value established after each semi-annual portable analyzer monitoring.

I.D.5.e.(ii)(C) Engines that are subject to catalyst temperatures and catalyst pressure drop monitoring requirements in an existing permit issued by the Division or 40 C.F.R. Part 63, Subpart ZZZZ (July 1, 2019) satisfy the monitoring requirements of this Section I.D.5.e.(ii).

I.D.5.e.(iii) Beginning May 1, 2021 or the date the engine is placed in service, modified, relocated or replaced (if later), install (if not already) and operate an hour meter or Division approved alternate method to continuously track the hours of operation of the subject engine.

I.D.5.e.(iv) Conduct the following inspections and adjustments at least annually, unless otherwise specified below, beginning in 2022

I.D.5.e.(iv)(A) Change oil and filters as necessary; and,

I.D.5.e.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary; and,

I.D.5.e.(iv)(C) Inspect spark plugs and replace as necessary; or,

I.D.5.e.(iv)(D) Conduct a combustion process adjustment according to the manufacturer recommended procedures and schedule. Alternatively, the owner or operator may rely on a combustion process adjustment conducted in accordance with requirements and schedules of a New Source Performance Standard in 40 CFR Part 60 (July 1, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (July 1, 2019) conducted during the same annual period to satisfy the annual combustion process adjustment requirement of this Section I.D.5.c.(iv)(D) for that 12-month period.

I.D.5.f. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request.

I.D.5.f.(i) Records of performance tests conducted pursuant to Section I.D.5.d, including I.D.5.d.(i)(D)., including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

I.D.5.f.(ii) Records of semi-annual portable analyzer monitoring, including the date, engine settings on the date of the monitoring, and documentation of the results of the monitoring. These records must include any demonstration that no semi-annual portable analyzer monitoring was required as provided under Section I.D.5.e.(i)(D) or I.D.5.e.(i)(E), if applicable.

I.D.5.f.(iii) Records of catalyst monitoring required by Section I.D.5.e.(ii) and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

I.D.5.f.(iv) If claiming an exemption under Section I.D.5.a.(ii), records demonstrating that fuel combustion was less than 100 MMBtu per year or hours of operation are less than 250 hours per year.

I.D.5.f.(v) Hours of operation as recorded by the hour meter or alternative device approved by the Division continuously tracking hours as required by Section I.D.5.e.(iii), at least on a calendar month basis.

I.D.5.f.(vi) Records of tuning, adjustments, or other combustion process adjustments required under Section I.D.5.e.(iv), including:

I.D.5.f.(vi)(A) The date of the adjustment.

I.D.5.f.(vi)(B) A description of any corrective action taken.

I.D.5.f.(vi)(C) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation since the last combustion process adjustment and the procedures followed. The owner or operator must retain documentation of any relied upon manufacturer recommended procedures, specifications, and maintenance schedule for five years after the owner or operator ceases to rely upon it.

I.D.5.f.(vi)(D) If the owner or operator conducts the combustion process adjustment according to a New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants, what standard applied and what procedures were followed.

I.D.5.g. Reporting. Beginning on the date specified below and by May 1 of each year thereafter, the owner or operator of each engine subject to this Section I.D.5. must submit the following information covering the preceding calendar year:

I.D.5.g.(i) Beginning May 1, 2021, a statement of the status of performance testing required under Section I.D.5.d, and the date and results of that testing;

II.D.5.g.(ii) Beginning May 1, 2022, an identification of any engines placed in service, modified, relocated, or replaced, including AIRS number, serial number, location, engine configuration, and a certification as to whether the emission standards in Table 2 are met;

I.D.5.g.(iii) Beginning May 1, 2022, the date on which the monitoring required by Sections I.D.5.e.(iv) was performed;

I.D.5.g.(iv) Beginning May 1, 2023, the date that all required semi-annual portable analyzer testing was performed under Section I.D.5.e.(i), and the results of that testing.

II. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area

II.A. Requirements for major sources of NOx

II.A.1. Applicability.

II.A.1.a. Except as provided in Section II.A.2., the requirements of this Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, located in the 8-Hour Ozone Control Area.

II.A.1.b. Except as provided in Section II.A.2., the requirements of Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, located in the 8-Hour Ozone Control Area, that is not already subject as provided under Section II.A.1.a.

II.A.2. Exemptions. The following stationary combustion equipment are exempt from the emission limitation requirements of Section II.A.4., the compliance demonstration requirements in Section II.A.5., and the related recordkeeping and reporting requirements of Sections II.A.7.a-e. and II.A.8, but these sources must maintain any and all records necessary to demonstrate that an exemption applies. These records must be maintained for a minimum of five years and made available to the Division upon request. Qualifying for an exemption in this section does not preclude the combustion process adjustment requirements of Section II.A.6., when required by II.A.6.a.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of this Section II.A. as expeditiously as practicable but no later than 36 months after any exemption no longer applies. Additionally, once stationary combustion equipment that is not equipped with CEMS or CERMS no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations of Section II.A.4.

II.A.2.a. Any stationary combustion equipment whose utilization is less than:

II.A.2.a.(i) 20% of its capacity factor on an annual average basis over a 3-year rolling period for boilers; or

II.A.2.a.(ii) 10% of its capacity factor on an annual average basis over a 3-year rolling period for stationary combustion turbines and compression ignition reciprocating internal combustion engines.

II.A.2.b. An engine testing operation or process line.

II.A.2.c. Any gaseous fuel fired stationary combustion equipment used to control VOC emissions from a commercial or industrial process.

II.A.2.d. Any stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx on a calendar year basis.

II.A.2.e. Any natural gas-fired reciprocating internal combustion engines subject to a work practice or emission control requirement contained in this Regulation 7, Section I.A. or B.

II.A.2.f. Any stationary combustion equipment subject to a federally enforceable work practice or emission control requirement contained in this Regulation 7, Section III.A.-B. or Regulation 3, Part F.

II.A.3. Definitions

II.A.3.a. "Affected unit" means any stationary combustion equipment that is subject to or becomes subject to an emission limitation in Section II.A.4.

II.A.3.b. "Boiler" means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

II.A.3.c. "Capacity factor" means the ratio of the amount of fuel burned by an emissions unit in a calendar year to the amount of fuel it could have burned if it had operated at the designed heat input rating for 8,760 hours during the calendar year. Alternatively, for electric generating units, capacity factor can mean the ratio of the unit's actual annual electric output (expressed in MWe/hr) to the electric output the unit could have achieved if it operated at its nameplate capacity (or maximum observed hourly gross load (expressed in MWe/hr) if greater than the nameplate capacity) for 8,760 hours during the calendar year.

II.A.3.d. "Ceramic kiln" means equipment used for the curing or firing of ceramic products or glaze on ceramic products. A kiln may operate continuously or by batch process.

II.A.3.e. "Continuous emission monitoring system" ("CEMS") or "Continuous emission rate monitoring system" ("CERMS") means the total equipment required to sample, condition (if applicable), analyze, and provide a written record of such emissions and/or emission rates, expressed on a continuous basis in terms of an applicable emission limitation. Such equipment includes, but is not limited to, sample collection and calibration interfaces, pollutant analyzers, a diluent analyzer (oxygen or carbon dioxide), stack gas volumetric flow monitors (if appropriate for CERMS), and data recording and storage devices.

II.A.3.f. “Compression ignition reciprocating internal combustion engine (RICE)” means a type of stationary RICE that is liquid fuel-fired and not ignited with a spark plug or other sparking device.

II.A.3.g. “Digester gas” means any gaseous byproduct of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide.

II.A.3.h. “Duct burner” means a device that combusts fuel and is placed in the exhaust duct from another source (e.g., stationary combustion turbine, internal combustion engine, or kiln) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

II.A.3.i. “Dryer” means a device that is used to reduce or evaporate moisture content or remove organic contaminants.

II.A.3.j. “Furnace” means an enclosed device that is an integral component of a manufacturing process and that uses thermal treatment to accomplish recovery of materials or energy.

II.A.3.k. “Gaseous fuel” means natural gas, landfill gas, refinery fuel gas, digester gas, methane, ethane, propane, butane, or any gas stored as a liquid at high pressure such as liquefied petroleum gas.

II.A.3.l. “Glass melting furnace” means an emissions unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass.

II.A.3.m. “Kiln” means the equipment used to remove combined (chemically bound) water and/or gases from mineral material through direct or indirect heating.

II.A.3.n. “Lightweight aggregate” means the expanded, porous product from heating shales, clays, slates, slags, or other natural materials in a kiln.

II.A.3.o. “Liquid fuel” means any fuel which is a liquid at standard conditions including but not limited to distillate oils, kerosene and jet fuel. Liquefied gaseous fuels are not liquid fuels.

II.A.3.p. “Process heater” means an enclosed device using controlled flame and a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

II.A.3.q. “Reciprocating internal combustion engine” means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not used to propel a motor vehicle or a vehicle used solely for competition.

II.A.3.r. "Stationary combustion equipment" means an emissions unit that combusts solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use. Stationary combustion equipment includes, but is not limited to, boilers, duct burners, engines, glass melting furnaces, kilns, process heaters, stationary combustion turbines, dryers, furnaces, and ceramic kilns.

II.A.3.s. "Stationary combustion turbine" means a non-mobile, enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine. Stationary combustion turbines can be simple cycle or combined cycle and they may or may not include a duct burner.

II.A.4. Emission limitations.

By October 1, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.a. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified.

By July 20, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.b. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified.

II.A.4.a. Boilers.

II.A.4.a.(i) For a gaseous fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(ii) For a liquid fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(iii) For a liquid or gaseous fuel-fired boiler at a major source of NOx (greater than or equal to 50 tpy NOx as of January 27, 2020) with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(iv) For a liquid or gaseous fuel-fired boiler at a major source of NOx (greater than or equal to 50 tpy NOx as of January 27, 2020) with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr but less than 100 MMBtu/hr, 0.1 lb/MMBtu of heat input or less than 83 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(v) Boilers subject to the categorical limits in Section II.A.4.a.(i) through (iv) or boilers with a maximum design heat input capacity less than 100 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.b. Stationary combustion turbines.

II.A.4.b.(i) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction on or before February 18, 2005 must comply with the following NOx emission limits in Table 1.

Table 1 – NOx limits for stationary combustion turbines constructed on or before February 18, 2005

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOx emission standard
Turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/MWh)
Turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3 lb/MWh).
Turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/MWh).
Turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines operating at less than 75 percent of peak load, turbines operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines operating at less than 75 percent of peak load, turbines operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

II.A.4.b.(i)(A) For units with heat recovery and CEMS, determine compliance on a 30-day rolling average.

II.A.4.b.(i)(B) For simple cycle turbines with CEMS, determine compliance on a 4-hour rolling average.

II.A.4.b.(i)(C) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

II.A.4.b.(i)(D) Emissions exceeding the NOx emission limits in Section II.A.4.b.(i) at any time, including during times of startup, shutdown, malfunction, fuel switching, tuning, and testing must be reported as specified in Section II.A.8.a.(i).

II.A.4.b.(ii) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction, modification or reconstruction after February 18, 2005 must comply with the applicable NOx emission limits in 40 CFR Part 60, Subpart KKKK (July 1, 2017).

II.A.4.b.(iii) Stationary combustion turbines subject to the categorical limits in Section II.A.4.b.(i) or (ii) above and stationary combustion turbines with a maximum design heat input capacity less than 10 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.b.(iv) Stationary combustion turbines, air pollution control equipment, and monitoring equipment must be operated in a manner consistent with good air pollution control practices for minimizing emissions at all times.

II.A.4.c. Lightweight aggregate kilns.

II.A.4.c.(i) For lightweight aggregate kilns with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr, 56.6 pounds of NOx per hour.

II.A.4.d. Glass melting furnaces.

II.A.4.d.(i) For, glass melting furnaces, 1.2 pounds of NOx per ton of glass pulled. However, days in which a glass melting furnace is operated at less than 35% of maximum designed production may be excluded from the 30-day rolling average for purposes of demonstrating compliance with this Section II.A.4.d.(i). During each day excluded from the 30-day rolling average, NOx emissions must be measured continuously in accordance with the applicable monitoring requirements of Section II.A.5, and the furnace must be operated in accordance with good air pollution control practices.

II.A.4.e. Compression ignition RICE.

II.A.4.e.(i) For a compression ignition RICE with a maximum design power output equal to or greater than 500 horsepower, 9 grams per brake horsepower-hour.

II.A.4.e.(ii) Compression ignition RICE subject to the emission limit in Section II.A.4.e.(i) above and compression ignition RICE with a maximum design power output less than 500 horsepower must comply with the combustion process adjustment requirements contained in Section II.A.6.

II.A.4.f. Landfill gas or biogas gas fired RICE.

II.A.4.f.(i) For landfill gas or biogas fired RICE with a maximum design power output equal to or greater than 500 horsepower, 2 grams per brake horsepower-hour

II.A.5. Compliance demonstration.

II.A.5.a. By October 1, 2021, for stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in this Section II.A.5.

II.A.5.b. By July 20, 2021, for stationary combustion equipment specified in Section II.A.1.b., the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in Sections II.A.5.

II.A.5.c. Emissions monitoring requirements for major source RACT limits

II.A.5.c.(i) Continuous emission monitoring

II.A.5.c.(i)(A) Owners or operators of an affected unit subject to a NOx emission limit in Section II.A.4.a.(i)-(iii), c. or d. must install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i). Owners or operators of affected units' subject to a NOx emission limit in Section II.A.4.b. or Section II.A.4.e. may install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i) in lieu of performance testing pursuant to Section II.A.5.c.(ii).

II.A.5.c.(i)(A)(1) The owner or operator of an affected unit that is subject to or becomes subject to the monitoring requirements of 40 CFR part 75 and 40 CFR part 75, Appendices A to I (July 19, 2018), must use those monitoring methods and specifications for monitoring NOx emissions for purposes of this Section II.A.5. and for demonstrating compliance with Section II.A.4. The missing data substitution procedures and bias adjustment requirements of 40 CFR Part 75 (July 19, 2018) do not apply for purposes of demonstrating compliance with Section II.A.4. or this Section II.A.5.

II.A.5.c.(i)(A)(2) For an affected unit equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with an applicable subpart of 40 CFR Part 60 (July 19, 2018), the owner or operator must use the definition of operating day, data averaging methodology, and data validation requirements of the applicable subpart of 40 CFR Part 60 for purposes of demonstrating compliance with an applicable emission limit in Section II.A.4. The owner or operator must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable requirements of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018).

II.A.5.c.(i)(A)(3) For an affected unit that is not equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with 40 CFR Part 60 (July 19, 2018) or Part 75 (July 19, 2018), the owner or operator must install, operate, and maintain a NOx CEMS or CERMS that measures emissions in terms of the applicable emission limitation and must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable provisions of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018). The owner or operator must use the following methodology for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section II.A.4.:

II.A.5.c.(i)(A)(3)(a) A unit operating day is a calendar day when any fuel is combusted in the affected unit.

II.A.5.c.(i)(A)(3)(b) 30-day rolling average emission rates must be calculated as the arithmetic average emissions rates determined by the CEMS or CERMS for all hours the affected unit combusted any fuel from the current unit operating day and the prior 29 unit operating days.

II.A.5.c.(i)(A)(4) When an affected unit utilizes a common flue gas stack system with one or more affected units, but no non-affected units, the owner or operator must follow the applicable procedures of 40 CFR Part 75, Appendix F (July 19, 2018) for the determination of all sampling locations and apportionment of emissions to an individual affected unit.

II.A.5.c.(i)(A) Owners or operators of a stationary combustion turbine subject to a NOx emission limit in Section II.A.4.b. must comply with

II.A.5.c.(i)(A)(1) The applicable monitoring requirements in 40 CFR Part 60, Subpart GG (July 1, 2017) for turbines which commenced construction on or before February 18, 2005.

II.A.5.c.(i)(A)(2) The applicable monitoring requirements in 40 CFR Part 60, Subpart KKKK (July 1, 2017) for turbines which commenced construction after February 18, 2005.

II.A.5.c.(ii) Initial and periodic performance testing

II.A.5.c.(ii)(A) An owner or operator of a stationary combustion turbine subject to 40 CFR Part 60, Subparts GG or KKKK (July 19, 2018) that has used and continues to use performance testing to demonstrate compliance with either Subpart GG or KKKK (July 19, 2018), as applicable, may use those performance testing procedures to demonstrate continued compliance with an applicable limitation contained in Section II.A.4.b., thereby satisfying the requirements of this section II.A.5.c.(ii).

II.A.5.c.(ii)(B) Except as otherwise provided for in Section II.A.5.a.(ii)(A), the owner or operator of an affected unit subject to a NOx emission limitation contained in Sections II.A.4.a.(iv), 4.b., or 4.e. that is not equipped with NOx CEMS or CERMS, must conduct an initial performance test and subsequent performance tests every 2 years thereafter, according to the following requirements, as applicable, to determine the affected unit's NOx emission rate for each fuel fired in the affected unit. A performance test is not required for a fuel used only for startup or for a fuel constituting less than 2% of the unit's annual heat input, as determined at the end of each calendar year.

II.A.5.c.(ii)(B)(1) Initial performance test must include a determination of the capacity load point of the unit's maximum NOx emissions rate based on one 30-minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, and 70 to 100%. Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NOx emissions rate.

II.A.5.c.(ii)(B)(2) Performance tests must determine compliance with Section II.A.4. based on the average of three 60-minute test runs performed at the capacity load determined in II.A.5.c.(ii)(B)(1).

II.A.5.c.(ii)(C) All performance tests must be conducted in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

II.A.5.c.(iii) For affected units' subject to a production-based or output based emission limit contained in Section II.A.4. (e.g. lb of NOx/ton of product), the owner or operator must install, operate, and maintain monitoring equipment for measuring and recording the affected unit's production or output, on an hourly basis, in units consistent with the applicable emission limitation.

II.A.5.c.(iv) Where measuring fuel use is necessary to calculate an emission rate in the units of the applicable standard, fuel flowmeters must be installed, calibrated, maintained, and operated according to manufacturer's instructions for measuring and recording heat input in terms of the applicable emission limitation. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of 40 CFR Part 75, Appendix D (July 19, 2018) are acceptable for demonstrating compliance with this section. The installation of fuel-flowmeters is not required where emissions of NOx in terms of the applicable standard can be calculated in accordance with applicable provisions of EPA Method 19 (July 19, 2018) or where the standard is concentration based (e.g. parts per million dry volume corrected for oxygen).

II.A.6. Combustion process adjustment

II.A.6.a. Applicability

II.A.6.a.(i) As of January 1, 2017, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016.

II.A.6.a.(ii) As of May 1, 2020, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, that is not already subject as provided under Section II.A.6.a.(i).

II.A.6.b. Combustion process adjustment

II.A.6.b.(i) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, the owner or operator must conduct the following inspections and adjustments of boilers and process heaters, as applicable:

II.A.6.b.(i)(A) Inspect the burner and combustion controls and clean or replace components as necessary.

II.A.6.b.(i)(B) Inspect the flame pattern and adjust the burner or combustion controls as necessary to optimize the flame pattern.

II.A.6.b.(i)(C) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly.

II.A.6.b.(i)(D) Measure the concentration in the effluent stream of carbon monoxide and nitrogen oxide in ppm, by volume, before and after the adjustments in Sections II.A.6.b.(i)(A) through (C). Measurements may be taken using a portable analyzer.

II.A.6.b.(ii) The owner or operator of a duct burner must inspect duct burner elements, baffles, support structures, and liners and clean, repair, or replace components as necessary.

II.A.6.b.(iii) The owner or operator of a stationary combustion turbine must conduct the following inspections and adjustments, as applicable:

II.A.6.b.(iii)(A) Inspect turbine inlet systems and align, repair, or replace components as necessary.

II.A.6.b.(iii)(B) Inspect the combustion chamber components, combustion liners, transition pieces, and fuel nozzle assemblies and clean, repair, or replace components as necessary.

II.A.6.b.(iii)(C) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, confirm proper setting and calibration of the combustion controls.

II.A.6.b.(iv) The owner or operator of a stationary internal combustion engine must conduct the following inspections and adjustments, as applicable:

II.A.6.b.(iv)(A) Change oil and filters as necessary.

II.A.6.b.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary.

II.A.6.b.(iv)(C) Inspect spark plugs and replace as necessary.

II.A.6.b.(v) The owner or operator of a dryer or furnace must inspect the burner and combustion controls and adjust, clean, and/or replace components as necessary.

II.A.6.b.(vi) The owner or operator of a ceramic kiln must inspect and maintain the combustion controls and adjust the burners as necessary to ensure a proper air-to-fuel ratio. At units where entry into a piece of process equipment is required to complete the combustion process adjustment, in-kiln inspections and adjustments are required only during planned entries.

II.A.6.b.(vii) The owner or operator must operate and maintain the boiler, duct burner, process heater, stationary combustion turbine, stationary internal combustion engine, dryer, furnace, or ceramic kiln consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

II.A.6.b.(viii) Frequency

II.A.6.b.(viii)(A) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, must conduct the initial combustion process adjustment by April 1, 2017. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016) to satisfy the requirement to conduct an initial combustion process adjustment by April 1, 2017.

II.A.6.b.(viii)(B) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, must conduct the initial combustion process adjustment by May 1, 2020. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) to satisfy the requirement to conduct an initial combustion process adjustment by May 1, 2020.

II.A.6.b.(viii)(C) The owner or operator must conduct subsequent combustion process adjustments at least once every twelve (12) months after the initial combustion adjustment, or on the applicable schedule according to Sections II.A.6.c.(1). or II.A.6.c.(ii).

II.A.6.c. As an alternative to the requirements described in Sections II.A.6.b.(i) through II.A.6.b.(viii):

II.A.6.c.(i) The owner or operator may conduct the combustion process adjustment according to the manufacturer recommended procedures and schedule; or

II.A.6.c.(ii) The owner or operator of combustion equipment that is subject to and required to conduct a periodic tune-up or combustion adjustment by the applicable requirements of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) may conduct tune-ups or adjustments according to the schedule and procedures of the applicable requirements of 40 CFR Part 60 (December 19, 2019) or 40 CFR Part 63 (December 19, 2019).

II.A.7. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request:

II.A.7.a. The applicable emission limit and calculated heat input weighted emission limit for stationary combustion equipment demonstrating compliance for multiple fuels.

II.A.7.b. The 30-day rolling average emission rate calculated on a daily basis for sources using CERMS to comply with Section II.A.

II.A.7.c. The type and amount of fuel used.

II.A.7.d. The stationary combustion equipment's annual capacity factor on a calendar year basis.

II.A.7.e. All records generated to comply with the reporting requirements contained in Section II.A.8.

II.A.7.f. For stationary combustion equipment subject to the combustion process adjustment requirements in Section II.A.6., the following recordkeeping requirements apply:

II.A.7.f.(i) The owner or operator must create a record once every calendar year identifying the combustion equipment at the source subject to Section II.A. and including for each combustion equipment:

II.A.7.f.(i)(A) The date of the adjustment;

II.A.7.f.(i)(B) Whether the combustion process adjustment under Sections II.A.6.b.(i) through II.A.6.b.(vi) was followed, and what procedures were performed;

II.A.7.f.(i)(C) Whether a combustion process adjustment under Sections II.A.6.c.(i). and II.A.6.c.(ii). was followed, what procedures were performed, and what New Source Performance or National Emission Standard for Hazardous Air Pollutants applied, if any; and

II.A.7.f.(i)(D) A description of any corrective action taken.

II.A.7.f.(i)(E) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation.

II.A.7.f.(i)(F) If multiple fuels are used, the type of fuel burned and heat input provided by each fuel.

II.A.7.f.(ii) The owner or operator must retain manufacturer recommended procedures, specifications, and maintenance schedule if utilized under Section II.A.6.c.(i). for the life of the equipment.

II.A.7.f.(iii) As an alternative to the requirements described in Section II.A.7.f.(i), the owner or operator may comply with applicable recordkeeping requirements related to combustion process adjustments conducted according to a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016).

II.A.7.g. All sources qualifying for an exemption under Section II.A.2. must maintain all records necessary to demonstrate that an exemption applies.

II.A.8. Reporting

II.A.8.a. For affected units demonstrating compliance with Section II.A.4. using CEMS or CERMS in accordance with Section II.A.5.c.(i)(A), the owner or operator must submit to the Division the following information:

II.A.8.a.(i) Quarterly or semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual or quarterly period, as applicable. Excess emissions means emissions that exceed the applicable limitations contained in Section II.A.4. Excess emission reports must include the information specified in 40 CFR Part 60, Section 60.7(c) (July 1, 2018).

II.A.8.b. For affected units demonstrating compliance with Section II.A.4 using performance testing pursuant to Section II.A.5.c.(ii)(C), the owner or operator must submit to the Division the following information:

II.A.8.b.(i) Performance test reports within 60 days after completion of the performance test program. All performance test reports must determine compliance with the applicable emission limitations set by Section II.A.4.

III. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-hour Ozone Control Area

III.A. Specific major sources of VOC and/or NOx (greater than or equal to 100 tpy) as of June 3, 2016, located in the 8-hour Ozone Control Area.

III.A.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017:

III.A.1.a. National Reconnaissance Office (NRO) – Aerospace Data Facility (005-0028) – engines (pt 128, 139, 144).

III.A.1.b. Colorado State University (069-0011) – engines (pt 024, 035, 036, 037, 038, 040, 043, 052).

III.A.1.c. DCP Midstream, Greeley (123-0099) – engine (pt 102).

III.A.1.d. DCP Midstream, Kersey/Mewbourn (123-0090) – engine (pt 101).

III.A.1.e. DCP Midstream, Spindle (123-0015) – engines (pt 059, 075).

III.A.1.f. IBM (013-0006) – engines (pt 092, 094).

III.A.1.g. Owens-Brockway (123-4406) – engine (pt 024).

III.A.1.h. Plains End (059-0864) – engine (pt 005).

III.A.1.i. PSCo Cherokee (001-0001) – engine (pt 031).

III.A.1.j. Spindle Hill (123-5468) – engine (pt 005).

III.A.1.k. Suncor (001-0003) – engines (pt 150, 151).

III.A.1.l. Timberline Energy (123-0079) – engines (pt 010, 011).

III.A.2. Cemex Construction Materials (013-0003) must comply with applicable THC requirements and associated monitoring, recordkeeping, and reporting in 40 CFR Part 63, Subpart LLL (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.A.3. Denver Regional Landfill and Front Range Landfill (123-0079) (pt 007, 013) must comply with applicable flare requirements in 40 CFR Part 60, Subpart WWW (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.B. Specific major sources of VOC and/or NOx (greater than or equal to 50 tpy) as of January 27, 2020, located in the 8-hour Ozone Control Area.

III.B.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (January 30, 2013) as expeditiously as practicable, but no later than July 1, 2021:

III.B.1.a. University of Colorado Denver, Anschutz Medical Campus (001-0106) – engines (pts 011, 012, 013, 014, 015, 016, 017, 018, 020, 021).

III.B.1.b. Centura Health St. Anthony (059-1511) – engines (pts 002, 003).

III.B.2. Flares at the following major sources must comply with applicable flare requirements in 40 CFR Part 60, Section 60.18 (December 22, 2008) as expeditiously as practicable, but no later than July 1, 2021.

III.B.2.a. Waste Management of Colorado Denver Arapahoe Disposal Site (005-1291) (pt 003).

III.B.3. Front Range Energy (123-5097) must comply with applicable monitoring, recordkeeping, and reporting in 40 CFR Part 60, Subpart VV (July 1, 2019) as expeditiously as practicable, but no later than July 1, 2021.

IV. Control of Emissions from Breweries in the 8-hour Ozone Control Area

IV.A. Requirements for Brewing Operations

IV.A.1. Applicability

Except as provided in Section IV.A.2., the requirements of Section IV. apply to owners or operators of breweries that existed at a major source of VOC (greater than or equal to 100 tpy VOC) as of June 3, 2016, located in the 8-hour Ozone Control Area.

IV.A.2. Exemptions

The following emissions units are exempt from Sections IV.A.4. through IV.A.7. but must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Owners or operators must also maintain records necessary to demonstrate than an exemption applies and make such records available to the Division upon request.

Once an emissions unit at a brewery no longer qualifies for an exemption, the owner or operator must comply with the applicable requirements of Sections IV.A.4. through IV.A.7. as expeditiously as practicable but no later than twelve (12) months after the exemption no longer applies, except as specified in Sections IV.A.2.c. and IV.A.2.d.

IV.A.2.a. An emissions unit subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7.

IV.A.2.b. An emissions unit with total uncontrolled actual emissions less than two (2) tons per year VOC on a calendar year basis.

IV.A.2.c. Equipment or activities related to research and development. Research and development ends when the product is sold or offered for sale.

IV.A.2.d. Newly installed, upgraded, or replaced packaging operations for a duration of six months after startup.

IV.A.3. Definitions

IV.A.3.a. “Brewery” means a source that produces malt beverage and is comprised of emissions units related to brewhouse operations, fermentation, aging or secondary fermentation, and/or packaging operations.

IV.A.3.b. “Packaging operation” means the canning, bottling, or filling of malt beverages into a container. Packaging operations include keg filling. Packaging operations do not include the railcar loading and unloading of beer concentrate shipped off-site for packing.

IV.A.3.c. “Pilot brewery operation” means an operation where total packaging operations are less than 50,000 barrels per year.

IV.A.3.d. “Process loss” means the difference between the quantity of malt beverage sent to packaging and the quantity of malt beverage packaged into a container. Process loss does not include malt beverage in filled containers if the malt beverage is processed after filling to remove or recover ethanol.

IV.A.4. Emission limitations. By May 1, 2019, no owner or operator of a brewery may exceed an average of 6 percent process loss across all packaging operations in a calendar month and 4 percent process loss on a 12-month rolling average during packaging operations.

IV.A.5. Packaging operation work practices

IV.A.5.a. The owner or operator must develop performance objectives and metrics for each packaging operation to reduce spillage and process loss. Process loss records must be summarized annually and compared to performance objectives established by the owner or operator. Process loss records and summaries must be made available to the Division upon request.

IV.A.5.b. The owner or operator must develop and implement an operator training program for employees engaged in packaging operations to understand the operation of the filling lines and minimize breakdowns, spillage, and process loss. The operator training materials must be made available to the Division upon request. At a minimum, the training program must include:

IV.A.5.b.(i) A brewery training manager, coordinator, or equivalent;

IV.A.5.b.(ii) Written standard operating procedures for packaging operations;

IV.A.5.b.(iii) A requirement that initial training be conducted for employees performing packaging operations and more frequently for the following:

IV.A.5.b.(iii)(A) Employees changing packaging operation responsibilities; and

IV.A.5.b.(iii)(B) Startup of new, upgraded, or replaced packaging operations.

IV.A.5.c. The owner or operator must use and maintain packaging operation equipment to reduce container breakage and process loss. For packaging operations, except at pilot brewery operations, this includes, but is not limited to:

IV.A.5.c.(i) Using and maintaining automated filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.c.(ii) Installing and operating fill level detectors to monitor the liquid fill levels in containers;

IV.A.5.c.(ii) Installing and operating crown inspectors to monitor the condition of crowns and/or caps applied to bottles, if applicable; and

IV.A.5.c.(iv) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.5.d. The owner or operator of pilot brewery operations must use and maintain packaging operation equipment to reduce container breakage and process loss. This includes, but is not limited to:

IV.A.5.d.(i) Maintaining filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.d.(ii) Monitoring the liquid fill levels in containers; and

IV.A.5.d.(iii) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.6. Wastewater management and treatment. Owners or operators employing microbial and vegetative destruction of VOCs through the land application of wastewater must ensure that the areas where wastewater is applied are areas covered with vegetation at all times when wastewater is applied, except as required following tilling and seeding for crop rotation and field work per standard agricultural practices.

IV.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request:

IV.A.7.a. Monthly records of the percent process loss for packaging operations;

IV.A.7.b. Records necessary to demonstrate compliance with the packaging operation work practice requirements in Section IV.A.5.; and

IV.A.7.c. If applicable, pursuant to Section IV.A.6., monthly and annual records of the amount of wastewater (gallons) sent to the land application site.

V. Control of Emissions from Foam Manufacturing in the 8-hour Ozone Control Area

V.A. Requirements for Foam Product Manufacturing

V.A.1. Applicability

Except as provided in Section V.A.2., the requirements of Section V. apply to owners or operators of foam manufacturing operations that existed at a major source of VOC (greater than or equal to 50 tpy VOC) as of January 27, 2020, located in the 8-hour Ozone Control Area.

V.A.2. Exemptions

Any foam manufacturing operation that uses only non-VOC blowing agents is exempt from this Section V.A.

V.A.3. Definitions

V.A.3.a. "Blowing agent" means any liquid, gaseous or solid substance that alone or in conjunction with other substances is capable of producing a cellular (foam) structure in a polymeric material.

V.A.3.b. "Expandable polystyrene (EPS) beads" means polystyrene beads, particles, or granules, usually less than one-twelfth inch in diameter, that are formulated with a blowing agent (typically 3.5% to 7% of bead weight). When subjected to prescribed heating in an expansion system, the beads puff up, expanding many times their original volume into low density foam globules (called "prepuff" or "puff") from which a variety of EPS foam products are molded.

V.A.3.c. "Expanded polystyrene (EPS) foam" means a lightweight, foam material, made of polystyrene, from which a variety of common items are made, such as ice-chests, insulation board, protective packaging, and single-use cups.

V.A.3.d. "Foam" means a solid material in a lightweight cellular form (having internal voids or cavities called cells that contain air or a gas) resulting from the introduction or generation of gas bubbles throughout its mass during processing.

V.A.3.e. "Foam manufacturing operation" means any EPS production line, or portion of a production line, which processes raw EPS bead into final molded EPS product. Production line processes include, but are not limited to: pre-expansion, aging (pre-puff), and molding. The manufacturing process ends after the product exits the EPS mold. "Foam manufacturing operation" also means any production line processing methylene diphenyl diisocyanate (MDI), resins, and various hardeners and thickeners into foam products and which results in VOC emissions into the atmosphere. The manufacturing process ends after the product exits the drying tunnel.

V.A.3.f. "Non-VOC blowing agent" means a blowing agent which does not contain VOCs.

V.A.3.g. "Polystyrene" means any grade, class, or type of thermoplastic polymer, alloy, or blend that is composed of at least 80% polymerized styrene by weight.

V.A.3.h. "Raw material" means all polystyrene, polyethylene and polypropylene, and blowing agent used in the manufacture of foam products.

V.A.4. Emission Limitations

V.A.4.a. By May 1, 2022, owners and operators of foam manufacturing operations must either

V.A.4.a.(i) Limit VOC emissions from foam manufacturing to 3.0 lbs. per 100 lbs. of total material process, averaged monthly, or

V.A.4.a.(ii) Control VOC emissions from foam manufacturing by 90%. The control device must have a control efficiency of at least 95%.

V.A.5. Work Practices

The owner or operator of any foam manufacturing operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources

V.A.5.a. Store raw materials in closed, leak-free, labeled containers when not in use.

V.A.5.b. Cover open containers in a manner that minimizes evaporation into the atmosphere.

V.A.6. Monitoring

V.A.6.a. The owner or operator of foam manufacturing operations must operate and maintain the control device consistent with the manufacturer's specifications.

V.A.6.b. By November 1, 2022, and every three (3) years afterward, owners or operator of foam manufacturing operations must conduct a performance test during representative operations using EPA Method 24 to determine VOC content and EPA Method 18, 25, or 25A to determine control efficiency of the emission control equipment.

V.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request

V.A.7.a. Any records necessary to demonstrate that an exemption in Section V.A.2. applies.

V.A.7.b. The amount of raw material processed on a daily basis.

V.A.7.c. The type of blowing agent used.

V.A.7.d. The amount of blowing agent used on a monthly basis.

V.A.7.e. The total monthly VOC emissions.

V.A.7.f. For operators complying with the emission limitation in Section V.A.4.a.(i), the total monthly VOC emissions calculated on a pounds per 100 lbs. of material processed basis.

V.A.7.g. For operators that use a control device to comply with the emission limitations in Section V.A.4.a.

V.A.7.g.(i) A manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section V.A.4.

V.A.7.g.(ii) The amount of supplementary natural gas combusted in the control device on a monthly basis.

V.A.7.g.(iii) Records of performance tests conducted pursuant to Section V.A.6.

V.A.7.h. Records of calendar year VOC emission estimates demonstrating whether the foam manufacturing operation meets or exceeds the applicability threshold in Section V.A.1.

V.A.8. Reporting

V.A.8.a. Performance test protocols required for performance tests under Section V.A.6.b. must be submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

PART F Statements of Basis, Specific Statutory Authority and Purpose

A. December 21, 1995 (Section II.B.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Numbers 3, 7, and the Common Provision are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists of the EPA list of non-photochemically VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all Colorado Air Quality Control Commission regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly-reactive VOC, industry's will be able to take advantage of and benefit from this possible shift in product contents.

B. March 21, 1996 (Sections I.A.1. through I.A.4.; II.D.; II.E.)

The changes to Regulation Number 7 were adopted as part of the Commission's decision to redesignate the Denver metro area as an attainment and maintenance area for ozone, together with the relevant amendments to the Ambient Air Quality Standards regulation and Regulation Number 3. The Ozone Maintenance Plan, also adopted by the Commission on March 21, 1996 as part of the redesignation, based part of its demonstration of maintenance on the continued existence of rules regulating VOC emissions. Such rules include the application of the permit requirements of Regulation Number 3 to gasoline stations, and the continued application of Regulation Number 7 for the control of VOC in nonattainment areas. The VOC controls in Regulation Number 7 were adopted into the SIP in May 1995, after Denver attained the ozone standard. The maintenance demonstration was based on future inventories that assumed the continuance of existing VOC controls in the Denver Metro area.

Pursuant to Section 25-7-107(2.5), C.R.S., the Commission is required to take expeditious action to redesignate the area as an attainment area for ozone. The CAA requires the submittal of a maintenance plan demonstrating maintenance of the ozone standard for any such redesignation request. The changes to Regulation Number 7 are consistent with continued maintenance of the ozone standard and are not otherwise more stringent than the relevant federal requirements.

The purpose of the revisions to Regulation Number 7, Section I.A is to provide a de minimis source with an opportunity to obtain an exemption from the requirements of Regulation Number 7 through rule-making. This revision will be submitted to the EPA for inclusion in the State Implementation Plan (SIP). Upon inclusion of this revision in the SIP, exemptions from Regulation Number 7 adopted by the Commission shall apply for purposes of both federal and state law, pending review by the state legislature pursuant to § 25-7-133(2), C.R.S. The rule revision includes several limitations on the scope of such exemptions:

1. The aggregate of all emissions from de minimis sources may not exceed five tons of emissions per day. The purpose of this limitation is to protect the projections contained in the emissions inventory, and to prevent growth in such emissions from exceeding the National Ambient Air Quality Standard (NAAQS) for ozone.

2. An exemption may not be granted if the Division demonstrates that such exemption will cause or contribute to air pollution levels that exceed the NAAQS, even if the total aggregate emissions from such sources is less than five tons per day.

3. The Commission rule prohibits more than one rulemaking hearing per year to consider potential de minimis exemptions in the aggregate. The purpose of this provision is to prevent the granting of case-by-case exemptions, and to conserve agency resources. The granting of exemptions on a case-by-case basis would grant an unfair advantage for those sources that are able to have their case heard by the Commission before other, similarly situated sources, submit a request for a de minimis exemption. However, upon a showing of an emergency, and at the discretion of the Commission, the Commission may always grant an exemption on a case-by-case basis.

4. The Commission rule provides that the growth in emissions due to such de minimis exemptions may not exceed the growth that was included in the emissions inventory in the SIP.

5. The Commission rule requires the de minimis exemptions to be included in a permit that is subject to review and comment by the public and by EPA.

The rule revision proposed by the Regional Air Quality Council (RAQC) did not include these limitations. However, the Commission may not have used the rule as proposed by RAQC to grant unlimited exemptions from the requirements of Regulation Number 7 because such an action would undermine the regulation and the maintenance demonstration contained in the SIP. The limitations adopted by the Commission were the subject of an alternative proposal submitted by the Division. The purpose of the limit is to ensure that the de minimis exemption provision cannot be used to jeopardize attainment of the NAAQs. Such a limit is necessary in order to obtain EPA approval of this SIP revision. The alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity. Even without an express provision limiting the de minimis exemptions to five tons per day, the Commission generally would not have granted de minimis exemptions in excess of that amount because such emissions are not accounted for in the emissions inventory and would undermine the maintenance demonstration. Furthermore, the alternative proposed by the Division does not, by itself, create an exemption from any regulatory requirement. The alternative simply limits the scope of the exemptions that may become fully effective without a SIP revision. However, the rule does not in any way limit the Commission's authority to amend the SIP.

The emissions inventory submitted to EPA anticipated growth in emissions in both the area source and minor source categories, as well as the major source category. In order to ensure that any growth in emissions due to the granting of de minimis exemptions will not cause total emissions to exceed the growth projections for these categories, the Division will keep track of the permitted allowable emissions that may result from sources and source categories entitled to such exemptions. In addition, the growth in emissions from area, major and minor source categories will be tracked when the Division performs the periodic inventories described in the SIP for the years 1999, 2002 and 2003. Any permitted growth in emissions due to de minimis exemptions will be added to the emissions for the source categories as reflected in the most recent periodic inventory. No further de minimis exemptions will be granted if the total growth in emissions exceeds the growth projections contained in the SIP. In addition, if the total growth exceeds the growth projections contained in the SIP, one or more of the contingency measures will be implemented to offset such growth, or the SIP will be revised as necessary to ensure continued maintenance of the standard.

The purpose of the addition of Regulation Number 7, Section II.E. is to provide sources with a process to obtain approval of an alternative emission control plan, compliance method, test method, or test procedure without waiting for EPA to approve of a site-specific SIP revision. The rule provides that any such alternative must be just as effective as the relevant regulatory provision, and that such effectiveness must be demonstrated using equally effective test methods and procedures. The changes to this section delegate the authority to the Division to approve of such alternatives. Since rulemaking is not required under Section II.E., the language allowing a source to assert that the relevant regulatory provision does not represent RACT has been omitted from this section. Such a change to the substantive requirements of Regulation Number 7 would require a rule change.

The rule revision proposed by the RAQC provided that alternative emissions control plans and compliance methods must be just as effective as those contained in the rule, but did not describe the test methods to be used to demonstrate such effectiveness. The Division proposed an alternative rule requiring such effectiveness to be demonstrated using test methods and procedures that are just as effective as those set out in the rule, or that have otherwise been approved by EPA. Such criteria for test methods and procedures are necessary in order to obtain EPA approval of this SIP revision. However, even without this language in the rule the Division would have required approved test methods and procedures in order to approve of proposed alternatives. The Division's alternative proposal provides the needed certainty in the most flexible manner possible.

Furthermore, the alternative proposed by the Division does not impose any new regulatory requirement. Instead, it merely establishes criteria for allowing persons' subject to the regulation to propose, in their discretion, an alternative means of complying with the existing regulatory requirements. Therefore, the alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity.

The rule revisions provide that no permit may be issued based on the provisions allowing for the creation of de minimis exemptions and the approval of alternative compliance plans without first revising the SIP unless EPA first approves of such regulatory revisions as part of the State Implementation Plan. The purpose of this condition is to address the possible disapproval of these revisions by EPA. In the event these changes are not approved by EPA, the remaining regulatory provisions of Regulation Number 7 will remain in full force and effect, and therefore, the EPA may approve of the maintenance plan and the redesignation request.

The revisions to Regulation Number 7 are procedural changes that are not intended to reduce air pollution.

For clarification, the Commission adopted these regulation revisions as follows:

REGULATION REVISION	OZONE SIP AND MAINTENANCE PLAN
Section I.A.1	Exists in Appendix C of the Ozone Maintenance Plan to become a part of that document approved March 21, 1996
Sections I.A.2., 3., 4.; Section II.D., II.E.	Adopted as subsequent regulation revisions to be submitted to the Governor and EPA separately and concurrently as a revision to the Ozone SIP (and Maintenance Plan)

The specific statutory authority to promulgate the rules necessary for redesignation is set out in §§ 25-7-105(1)(a)(I) and (2); -106(1)(a); -107 (1) and (2.5); and -301. The authority to adopt such rules includes the authority to adopt exceptions to the rules, and the process for applying for any such exemptions.

C. November 21, 1996 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally, because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Numbers 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3, Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(I)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulation Numbers 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

D. October 15, 1998 (Section II.F.)

The Gates Rubber Co. Site-specific Revision

The Gates Rubber Co. (Gates), by and through its attorney, submitted this Statement of Basis, Specific Statutory Authority and Purpose for amendments to Regulation Number 7, Control of Emissions of Volatile Organic Compounds.

Basis

Regulation Number 3 contains a certification and trading of emission reduction credits section (Section V), which sets forth the definitions and process for obtaining emission credits and using those credits. This section was amended to permit the use of emission reduction credits (ERC) to satisfy reasonably available control technology (RACT) requirements. The criteria for approval of ERC transactions specifies that they must involve like pollutants (for volatile organic compounds, the same degree of toxicity and photochemical reactivity), must be within the same nonattainment area, may not be used to satisfy Federal technology control requirements and may not be inconsistent with standards or regulations or to circumvent new source performance standards, best available control technology, lowest available emission rate technology controls or NESHAPs.

Regulation Number 7 sets forth CTG and RACT emission limitations, equipment requirements and work practices intended to control emission of volatile organic compounds (VOC) from new and existing stationary sources. The control measures specified in Regulation Number 7 are designed to reduce the ambient concentrations of ozone in ozone nonattainment areas and to maintain adequate air quality in other areas.

Specific Statutory Authority

The provisions of C.R.S. §§ 25-7-105 and 25-7-109 to 110 provide the specific statutory authority for the amendments to this regulation adopted by the Commission. The Commission has also adopted in compliance with C.R.S. § 24-4-103(4), this Statement of Basis, Specific Statutory Authority and Purpose.

Purpose

The purpose of this amendment to Regulation Number 7 is to establish a source specific rule for Gates to allow the use of emission reduction credits to satisfy the RACT requirements for VOC emissions pursuant to Regulation Number 7 for surface coatings operations not specifically listed in Section IX of Regulation Number 7. Regulation Number 3 provides specific authorization to use emission reduction credit transactions as an alternative compliance method to satisfy CTG and RACT requirements.

Specifically, the VOC certified emissions reduction credits to be used in this emission credit transaction in an amount up to 12 tons per year are from Coors Brewing Company pursuant to their emissions reduction credit Permit. The emission reduction credits will be used to satisfy the general requirements that all sources apply RACT. These emission reduction credits will be used by Gates so that Gates can use solvent-based surface coatings which contain VOCs periodically in lieu of the water-based coatings normally used on its 10 Cord coating line (S033, S034, and S035). These credits will allow Gates to meet RACT requirements without applying control technology to the 10 Cord line, other than the currently installed catalytic incinerator on the emissions from the drying oven from the fourth dip, which reduces those emissions by at least 90%. The relevant portion of Regulation Number 3, which applies to the Gates credit transaction is Section V.F., entitled “Criteria for Approval of all Transactions.” The first requirement is that the transaction involve like pollutants. In the present case, the emission credit transaction involves the exchange of VOC pollutants. Coors credits for methanol will be exchanged for m-pyrol. Exhaust from the catalytic incinerator, which contains unconverted toluene and xylene, is routed to the curing ovens of the other zones of the 10 Cord line, including the first zone. The Division has previously found that, excluding the emissions from the non-compliant coatings addressed in this rule, the 10 Cord line has met RACT standards. The use of the non-compliant coatings adds no HAPs to the Gates emissions. Other non-criteria reportable pollutants are present at well below APEN de minimis quantities under scenario 2, which is applicable to the 10 Cord line. Regulation Number 3 further requires that toxic or VOC pollutants involve the same degree of toxicity and photochemical reactivity or else a greater reduction may be required. Since these pollutants are both toxics and VOCs (except that m-pyrol is not a toxic), both have been addressed.

All of these compounds are commonly used in the surface coating industry with appropriate safeguards during their use. With respect to toxicity of the Gates compounds, m-pyrol is not listed as a toxic compound on either the federal or state lists. Methanol, the VOC in the Coors credit, is a Bin C HAP. Because the m-pyrol in the non-compliant coatings is not a HAP, the Gates VOCs have equal or lower toxicity than those being purchased from Coors. Therefore, HAP emissions will be reduced in the airshed.

The photochemical reactivities of VOCs are important because of their impact on the ozone formation process in an airshed. The Air Pollution Control Division relied upon the work of Dr. William P.L. Carter, Professor at the University of California, whose article entitled “Development of Ozone Reactivity Scales for Volatile Organic Compounds” describes relative photochemical reactivity scales and comparisons. Dr. Carter notes that there are a number of ways to quantify VOC reactivities, but the most relevant measure of VOC effects on ozone is the actual change in ozone formation in an airshed. This results from changing the emissions of the VOC in that airshed which depends not only on how rapidly the VOC reacts and the nature of its atmospheric reaction mechanism, but also the nature of the airshed where it is emitted, including the effects of other pollutants which are present.

Dr. Carter further states that the VOC effect on ozone in the atmosphere can only be estimated using computer airshed models. The effect of changing the emissions of a given VOC on ozone formation in a particular episode will, in general, depend on the magnitude of the emissions change and on whether the VOC is being added to, subtracted from, or replacing a portion of the base case emissions.

Dr. Carter's derived relative reactivity scale includes reactive organic gases whose indices for maximum incremental reactivity (MIR) range from 0.004 to 6.5. The MIR values were updated in 1997. The VOCs and their respective MIR involved with this exchange are as follows:

Methanol	0.16
m-Pyrol	0.57

The pending emission credits of VOCs being used in the proposed emissions credit transaction are for methanol. The VOCs emitted from uncontrolled use of solvent-based coatings at Gates are from m-pyrol. Regulation Number 3 provides that if the VOCs are not of the same photochemical reactivity, a greater offset may be required. The Commission required that, based on a past ERC trade for Pioneer Metal Finishing, that methanol credits in a 1.1:1 offset ratio be exchanged for toluene and xylenes. Here, however, the Commission finds that m-pyrol and methanol have similar photochemical reactivities, so no offset will be required.

The second requirement states that the transaction must not result in an increased concentration, at the point of maximum impact of hazardous air pollutants. This provision was derived from the EPA Emissions Trading Policy Statement and referred to NESHAP requirements involved in bubble transactions. If this provision is interpreted to apply generally to a facility which is limited by an existing permit to some level of VOC emissions on a twenty-four-hour basis, any additional VOCs allowed pursuant to an emission transaction would by its application increase the concentration of VOCs at the maximum point of impact. Since it appears to have been intended to limit NESHAP offsets in bubble transactions, and no NESHAPs are applicable in the Gates transaction, and recognizing the earlier action of the Commission in approving the use of ERC transactions to satisfy CTG requirements and in approving a previous ERC transaction for Pioneer Metal Finishing, the Commission determined that this requirement should not apply to this transaction.

The next requirement states that no transaction may be approved which is inconsistent with any standard established by the Federal Act, the state Air Quality Control Act or the regulations promulgated under either, or to circumvent NSPS requirements or BACT or LAER, although the Commission may approve a transaction using a certified emission reduction credit in lieu of a specified CTG method or RACT. The emissions involved in this transaction at Gates are not subject to NSPS, BACT, or LAER. Regulation Number 7 applies only RACT to the Gates operations involved. Regulation Number 3 clearly permits the use of emission reduction credits to satisfy RACT.

The emission must involve sources which are located within the same nonattainment area. In the present case, both Gates, whose operations are located at 900 S. Broadway, Denver, Colorado, who is proposing to use the credits, and the source of the credits, Verticel, whose operations were located at 4607 South Windermere Street, Englewood, Colorado, are located in the Denver nonattainment area, less than five miles apart.

The next requirement prohibits the use of emission reduction credits to meet applicable technology-based requirements for new sources, such as NSPS, BACT, or LAER. As stated, the Gates operations involved in this transaction are not subject to NSPS, BACT, or LAER or any other technology-based requirement except for RACT requirements for which an ERC transaction may be used to satisfy such requirements.

The next requirement states that VOC trades will be considered equal in ambient effect where the trade is a pound for pound trade in the same control strategy demonstration area. It appears that this requirement, which was taken from the EPA Emissions Trading Policy Statement, made the assumption that the “pound for pound” trend would have an equal impact on the ambient environment, with respect to ozone. Since there was no independent photochemical reactivity equivalency requirement in the 1986 Policy Statement, this requirement appears to be redundant with the requirement for insuring the same degree of photochemical reactivity among traded pollutants.

For VOC trades involving surface coating, the requirements state that emissions must be calculated on a solids-applied basis and must specify the maximum time period over which the emissions may be averaged, not to exceed 24 hours. The proposed emissions credit transaction is based on a 24-hour period. With respect to the solids-applied basis calculation, this transaction will be calculated on the basis of the pounds of VOCs from uncontrolled solvent-based coatings.

The emissions credit transaction will require a SIP revision. The source specific rule for Gates will be forwarded to EPA for approval. The state emissions permit for Gates pursuant to the emissions credit transaction will be state effective (but not federally effective) until the SIP revision is approved by EPA.

Gates proposed the following VOC emissions limitation in its state permit taking into consideration the pounds per year VOC emissions allowed by this emissions credit transaction:

1. A daily maximum limitation of 400 lbs. of VOC emissions from uncontrolled solvent-based surface coatings, calculated on a monthly basis for compliance purposes. Calculations will be performed by the 30th of the following month.

2. An annual limitation of no more than 24,000 lbs. (12 tons) of VOC emissions from uncontrolled solvent-based surface coatings.

Gates proposes to calculate the annual total VOC limitation on a rolling 12-month basis. Gates further proposes to keep monthly totals of non-compliant surface coatings used and to calculate daily usage based on monthly usage divided by the number of days’ non-compliant surface coatings were used. Records of usages and calculations will be kept and produced at the Division's request.

This source-specific rule has a negligible or no effect upon the other provisions of the ozone SIP.

It is contemplated that a State construction permit will be issued to Gates upon final approval by the Commission. Should the approval come after the issuance of Gates' Title V operating permit, the terms of the construction permit will be added to the operating permit.

E. January 11, 2001 (Sections III.C., IX.L.2.c.(1), and X.D.2. through XI.A.3.)

Readoption of Changes to Regulation Number 7 that were not printed in the regulation or the Colorado Code of Regulations.

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Basis

During a review of the version of Regulation Number 7 adopted by the Air Quality Control Commission and the version of Regulation Number 7 published in the Colorado Code of Regulations, several significant discrepancies have been identified. This rule making will clarify the Commission's intent to adopt the following revisions to Regulation Number 7:

1. Section III.C regarding General Requirements for Storage of Volatile Organic Compounds omits the following revision:

   "Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 PSIA at actual conditions are exempt from the provisions of Section III.B."

2. Section IX.L.2.c.(i) contains discrepancies in reference to the permit number of Coors Brewing Company Emissions Reduction Credit Permit issued on July 25, 1994.

3. Section X.D.2. through Section XI.A.3. was omitted from the CCR as published in the current version of Regulation Number 7.

Authority

Sections 25-7-109, C.R.S. (1997) authorize the Commission to adopt emission control regulations.

Purpose

Re-adoption of the proposed rule will eliminate the discrepancies between the Commission's adopted provisions within Regulation Number 7 and those contained within the Colorado Code of Regulations. Adoption of the amendments will benefit the regulated community by providing sources with consistent information.

F. November 20, 2003 (Sections I.A.2. through I.A.4., II.D. and II.E.)

The Commission repealed the provisions establishing a procedure for granting exemptions for de minimis sources, and the procedure for approving alternative compliance plans without source-specific SIP revisions. The Commission had adopted the repealed provisions in March 1996, but had delayed the effective date pending EPA approval through the SIP revision process. Earlier this year, EPA informed the Commission of its intent to disapprove the provisions unless they were withdrawn. Thus, the provisions that are the subject of this rulemaking action never took effect. The Commission hereby repeals such provisions in order to avoid disapproval of the earlier SIP submittal, and to remove extraneous provisions from Regulation Number 7. Such repeal is required in order to comply with federal requirements, and is not otherwise more stringent than the requirements of the federal act.

Sections 25-7-105(1)(a)(I) and 25-7-301 authorize the Commission to adopt and revise a comprehensive SIP, and to regulate emissions from stationary sources, as necessary to maintain the national ambient air quality standard for ozone in accordance with the federal act.

G. (March 2004, Sections I.A, I.B., XII., and XVI.

The March 2004 revisions were adopted in conjunction with the Early Action Compact Ozone Action Plan, which is a SIP revision for attainment of the 8-hour ozone standard by December 31, 2007. The Commission adopted four new control measures in Regulation Number 7 to reduce emissions of volatile organic compounds (VOC). The control measures require the installation of air pollution control technology to control: (1) VOC emissions from condensate operation at oil and gas (E&P) facilities; (2) emissions from stationary and portable reciprocating internal combustion engines; (3) certain VOC emissions from gas-processing plants; and, (4) emissions from dehydrators at oil and gas operations.

The new requirements in Sections XII., and XVI. apply to a larger geographic area than the pre-existing requirements of Regulation Number 7, as set out in Section I.A. of the rule. The reference to the "Denver Metro Attainment Maintenance Area", which is not a defined term, in Section I.A was changed to refer to the "Denver 1-hour ozone attainment/maintenance area", which is defined in the Ambient Air Quality Standards Rule. Similarly, the reference to the "Denver Metropolitan Nonattainment Area Ozone Maintenance State Implementation Plan" was changed to the "Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area," which is the correct name of the document submitted to EPA in May 2001.

Regarding VOC emissions from condensate operations, the Commission has determined that an overall reduction of 47.5% VOCs is required of each E&P operation so as to meet the requirements of the SIP. Further the Commission decided not to take a unit-by-unit approach, but rather, the amendments take a more flexible approach to regulating such emissions by requiring sources that have filed, or were required to file, APENs to choose emission controls and locations for applying those controls. This approach also minimizes the risk that sources may reconfigure tanks to avoid implementing the regulation.

Section XII.A.6. provides an exemption for owners and operators with less than 30 tpy of flash emissions subject to APEN reporting requirements. Regulation Number 7 previously included more general exemptions for emissions from condensate operations, but such pre-existing exemptions should have been repealed as part of this revision to Regulation Number 7. To the extent any pre-existing exemption for condensate operations remains, such pre-existing exemption shall not be construed to supersede the requirements of Section XII.

The rule also requires annual reports describing how E&P sources will achieve the requisite emission reductions. Such reports are necessary so that the Division can determine whether or not the emission reductions are being achieved.

Section XII.B. of Regulation Number 7 is required to ensure that existing and new natural gas processing plants employ air pollution control technology to control emissions from leaking equipment, and atmospheric condensate storage tanks (and tank batteries). The Commission is specifically requiring a leak detection and repair (LDAR) program for all gas plants, according to the provisions of 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the affected facility. This is necessary to ensure these large facilities are well controlled and VOC emissions minimized.

Section XII. C. pertains to control of VOC emissions from natural gas dehydration operations. The Commission determined that, in order to meet the requirements of the SIP, emissions must be reduced from all dehydration operations located in the 8-hour Ozone Control Area if such operations produce emissions above the minimum threshold specified in the rule. Further the Commission decided that flexibility should be allowed in how emissions are reduced, so several options are listed from which a source owner or operator may choose. If other equally effective measures or control devices are available, the Division may, on a case-by-case basis, approve the use of such alternatives.

Similarly, Section XVI. establishes controls for reciprocating internal combustion engines. Both "lean" and "rich" burn engines are addressed and though the Commission has specified the default control technology to be applied to each engine type, the Division is allowed to approve alternative technology if a demonstration can be made that the alternative is at least as effective as the listed device in reducing VOC emissions. Parties to the rulemaking hearing provided evidence that suitable, cost-effective control equipment may not be available for some existing engines. The rule adopted by the Commission includes an exemption for lean burn engines if the owner demonstrates that such emissions controls would cost $5,000 or more per ton of VOC removed. In calculating such costs, the Division shall use an appropriate amortization period and current discount rate. The Commission directs the Division to further investigate the question of whether controls are available and suitable for lean burn engines, and to recommend any revisions necessary for the regulation applicable to such engines. New engines locating in the control area must comply with the requirements effective June 1, 2004, but existing engines have until May 1, 2005 to come into compliance. Since the rule provides an exemption for existing engines that cannot be controlled for less than $5,000 per ton, the rule must make the distinction between new and existing engines so that engines will not be moved into the area during prior to May 2005 and subsequently apply for such an exemption.

The Commission recognizes that, at this point in time, the controls required by the rule amendments constitute Reasonably Available Control Technology (RACT), at a minimum, and in some cases, the controls mandated by this regulation may, in fact, constitute Best Available Control Technology (BACT). This means that this regulation shall not be used: (a) to preclude a source from asserting that one of the controls mandated herein constitutes BACT or Lowest Achievable Emissions Rate (LAER) for a new source or major modification, (b) require the Division or Commission to mandate different control technologies as BACT, or (c) preclude the Division or Commission from requiring additional or more stringent air pollution control technologies as necessary or appropriate to comply with applicable BACT or LAER requirements for new sources and major modifications.

By its terms, the New Source Performance Standard (NSPS) applicable to leaking equipment at onshore natural gas processing plants (40 CFR Part 60, Subpart KKK) applies to “affected facilities” and “process units” at such facilities as those terms are defined in the standard. In general, plants that were constructed prior to January 20, 1984 are exempt from the standard, unless subsequently modified or reconstructed, or newly constructed after that date. Since process units at a single gas plant can be distinct, certain gas plants may contain equipment that is not presently subject to the NSPS because of its date of construction. The control requirement in Section XII.B. would extend leak detection and repair program requirements to such equipment.

The statutory authority for the revisions to regulation Number 7 is set out in Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The March 2004 revisions to Regulation Number 7 are based on reasonably available, validated, reviewed, and sound scientific methodologies. All validated, reviewed and sound scientific methodologies and information made available by interested parties has been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution. The Commission chose the most cost-effective mix of control strategies available to comply with the 8-hour ozone NAAQS. Where possible, the regulations provide the regulated community with flexibility to achieve the necessary reductions. The Commission chose the regulatory alternative that will maximize the air quality benefits in the most cost-effective manner.

H. (December 2004, SECTIONS I.A., II.A., XII. and XVI.)

The December 2004 revisions were adopted to respond to U.S. EPA comments on the Ozone Action Plan the Commission adopted in March 2004. EPA required the rule revision in order to make the control measures incorporated into the State Implementation Plan practically enforceable as required by the federal Clean Air Act. The Federal Act requires all of the regulatory provisions adopted in this rulemaking action, and none of the provisions are more stringent than the requirements of the federal act.

The revised rule includes a process for obtaining emission reduction credit for pollution prevention measures. In order to qualify for an emission reduction credit, a pollution prevention measures must, among other things, be included in a permit even if it does not involve the construction of an air pollution source and would not otherwise trigger a requirement for a permit. The revisions to the regulation do not, however, create a requirement for sources to obtain a permit for pollution prevention measures for which the source will not take emissions reduction credit.

The Commission has the statutory authority to adopt the revisions pursuant to Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The control measures necessary to achieve the 8-hour ozone standard were adopted in March 2004. The December 2004 rule changes do not impose new emission control requirements or emission reduction requirements on industry. Instead, the December 2004 rule revisions are intended to make the previously adopted requirements more enforceable, and to make sure that the requisite emission reductions occur during the ozone season when they are needed. Thus, the December 2004 are administrative in nature in that they are intended to assist with the administration and enforcement of the previously adopted controls. The Commission recognizes that the December 2004 rule amendments impose additional recordkeeping and reporting requirements, and therefore costs, on the regulated community. The changes, however, are not intended to achieve further reduction in emissions of volatile organic compounds beyond the reduction requirements adopted in March 2004. They are instead intended to make the March 2004 revisions fully enforceable and acceptable to EPA. Since the December 2004 rule changes are administrative in nature, the requirements of Section 25-7-110.8 C.R.S. do not apply.

I. December 17, 2006 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

<u>Basis</u>

Regulation Number 7, Section XII imposes emission control requirements on oil and gas condensate tanks located in Adams, Arapahoe, Boulder, Douglas and Jefferson Counties, the Cities and Counties of Broomfield and Denver and parts of Larimer and Weld Counties ("8-Hour Ozone Control Area"). The condensate tank requirements, along with other requirements applicable to oil and gas operations and natural gas fired reciprocating internal combustion engines, were initially promulgated in March 2004, and later revised in December 2004, in connection with an Early Action Compact Ozone Action Plan ("EAC") entered into between the State of Colorado and the United States Environmental Protection Agency. The purpose of the EAC is to prevent exceedances of the 8-Hour Ozone Standard and avoid a nonattainment designation for the area. Pursuant to the EAC, Colorado committed to limiting Volatile Organic Compound ("VOC") emissions from condensate tanks located in the 8-Hour Ozone Control Area to 91.3 tons per day ("TPD") as of May 1, 2007 and 100.9 TPD as of May 1, 2012. Because of unanticipated growth of condensate tank emissions since 2004, the control requirements for condensate tanks adopted during the 2004 rulemaking are insufficient to meet these daily emission numbers. The current revisions require a greater level of control of condensate tank emissions in the 8-Hour Ozone Control Area in order to meet the commitments set forth in the EAC and to prevent future exceedances of the 8-Hour Ozone Standard.

These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Section, 25-7-105(1)(a), C.R.S., which gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of a comprehensive state implementation plan that will assure attainment of national ambient air quality standards. Additional authority for these revisions is set forth in Sections, 25-7-106 and 25-7-109, which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to specified areas within the state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XII. were adopted in order to meet the commitments with respect to condensate tank emissions set forth in the Early Action Compact Ozone Action Plan entered into between the State of Colorado and U.S. EPA, prevent exceedances of the 8-Hour Ozone Standard, and simplify recordkeeping and reporting requirements. To accomplish these goals, the revised regulation raises the system-wide control requirements for the ozone season from the current 47.5% to 75% commencing in 2007 and 78% in 2012. While the rule establishes a higher percentage reduction in 2012 the Commission recognizes that given the uncertainty of emissions growth over the next 6 years, this reduction requirement may be too high and may need to be revisited as the 2012 deadline approaches. For the non-ozone season the required reduction has been raised from 38% to 60% commencing October 2007, and 70% commencing January 1, 2008. Determination of compliance during the ozone season under the revisions will be on a weekly basis instead of a daily basis, in recognition of the fact that condensate production is not typically measured on a daily basis. Under the previous version of the Rule, production could be tracked on something greater than a daily basis and the total divided by the number of days to obtain a daily number. As such, the prior rule did not truly give a daily average and thus the move to a weekly average is of little substance. Apart from this change, calculation of emissions for compliance purposes will remain the same as under the previous version of the rule.

In addition to raising the system-wide reduction requirements, the current rule adds significant new monitoring, record-keeping and reporting requirements, and a “backstop” threshold requirement to have emission controls on all condensate storage tanks with uncontrolled actual emissions of 20 tpy or more of VOC flash emission, as a state-only requirement within the EAC area pursuant to Section XVII.C.1. of Regulation Number 7. Owners and operators will continue to keep a spreadsheet that tracks emission reductions and submit an Annual Report as required under the previous version of the rule. Owners and operators are now also required to submit a semi-annual report on November 30 of each year detailing their emissions during the preceding ozone season. Additional record keeping has been added so as to require that a weekly checklist be maintained detailing inspections of control devices. This checklist will assist operators in the inspection and maintenance practice and provide a record that proper inspections have been done. If the inspections show a problem with the control device, the owner or operator will be required to notify the Division of problems on a monthly basis. This requirement will allow the Division to track problems on a timelier basis and ensure compliance with the rule. Finally, a provision has been added to require owners or operators to submit a list of all their controlled tanks on April 30 of each year and notify the Division monthly during ozone season if the control status of any tank changes.

J. December 17, 2006 (Sections I.A.1.b. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted these state-only provisions as a means of reducing air emissions from oil and gas operations throughout Colorado. Due to the large growth in oil and gas production in a number of regions of the state emissions from oil and gas operations have rapidly increased over the past few years and are expected to increase further in the foreseeable future. These revisions are a proactive measure designed to eliminate air emissions that could threaten attainment of ambient air quality standards and adversely affect visibility in Class I Areas. These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-106 and 25-7-109 of the Colorado Air Pollution Prevention and Control Act (“Act”), which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Additional authority is set forth in Section 25-7-105.1, which allows the Commission to adopt state-only standards. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to the entire state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XVII. were adopted in order to reduce air emissions from oil and gas operations and natural gas fired reciprocating internal combustion engines in Colorado. These revisions constitute a forward-looking approach to deal with a rapidly growing source of air emissions, and are designed to reduce the possibility of future problems with respect to the attainment of National Ambient Air Quality Standards and state and federal Class I Area visibility goals. Since the requirements are not mandated under federal law and are not currently necessary to meet National Ambient Air Quality Standards they are being adopted as a state-only requirement in accordance with the Act and as provided for under the Federal Clean Air Act.

These revisions establish emission control requirements for condensate storage tanks, glycol dehydrators and natural gas fired reciprocating internal combustion engines in Colorado. These provisions require that condensate tank and dehydrator controls meet a 95% percent control efficiency. As in the EAC Area, this requirement does not contemplate stack testing in order to verify the control efficiency. The insertion of the word average allows operators some downtime without a violation occurring so long as the downtime does not result in an average control efficiency of less than 95% considering the actual engineered control efficiency. For the purposes of XVII.C.4.b. observed operation of flare auto-igniters can include telemetric monitoring systems, physical on-site function tests or auditory confirmation of the auto-igniter function.

The requirements applicable to glycol dehydrators mirror the requirements applicable in the 8-Hour Ozone Control Area set forth in Section XII, and should be interpreted consistently with those provisions notwithstanding the addition of clarifying language. For example, language has been added clarifying that grouping of dehydrators is limited to dehydrators at a single site. Similarly, the word “production” has been added to the definition of condensate tank to clarify that the requirements, as within the EAC, do not apply to produced water tanks.

Determination of whether a condensate tank’s emissions are at or above the threshold is based on the emissions from the tank during the preceding twelve-month period. If a tank has been in service for less than twelve months, applicability shall be based on uncontrolled actual emissions over the service period of the tank multiplied out to twelve months. Accordingly, if a tank has been in service for three months, applicability of the control requirements will be based on the uncontrolled actual emissions from the tank for those three months multiplied by four. If emissions from a controlled tank decrease, operators may remove the controls when emissions from the previous twelve-month period falls below the applicable threshold. Operators will remain responsible, however, for controlling a tank if a subsequent emission increase results in emissions being over the applicable threshold during the preceding twelve months. For tanks serving newly drilled, recompleted or restimulated wells (including refrac’d wells) the owner or operator will have 90 days to determine anticipated production and, if necessary install a control device. In determining anticipated production, the owner or operator may use an appropriate decline factor to determine expected emissions over the first 12 months after the new drilling, recompletion or re-stimulation. If the owner or operator determines that emissions will be below the 20 tpy threshold following the new drilling, recompletion or restimulation, the owner or operator shall notify the Division of this determination.

Certain differences with the requirements applicable to the 8-Hour Ozone Control Area have been included in order to provide greater flexibility to operators in other areas of the state and in light of the fact that the regulation represents a proactive attempt to avoid future impacts from oil and gas emissions. Specifically, the standards for obtaining approval of an alternative pollution control device have been relaxed to promote innovative control strategies. Additionally, a provision has been added to allow an extension of the control requirement deadlines at the Division’s discretion for good cause shown. This provision allows the Division to extend a deadline where shortages of control equipment, and crews may prevent an operator from meeting the deadlines, particularly in areas where access is limited by the weather or other issues. With respect to Section VII.B.1.c. of the General Provisions, the Commission has determined that as a general rule during normal operations no emissions should be visible from the air pollution control equipment.

Normal operations include reasonably foreseeable fluctuations in emissions from the condensate tank, including the fluctuations that occur during a separator dump. However, a transient (lasting less than 10 seconds) “puff” of smoke when the main burner ignites or shuts down would not be considered a violation of the “no visible emission” standard. Finally, a provision has been included that exempts units’ subject to the rule if such units are also subject to a control standard under the MACT, BACT or NSPS Programs. This exception is of most importance for new and newly relocated engines that may become subject to a currently pending NSPS Standard under Subpart JJJJ.

The engine provisions only apply to engines that are constructed or relocated into Colorado after the applicability date and do not impose requirements on units that are currently located in the state.

The Commission recognizes that the adopted emission control requirements represent a first step in addressing rapidly growing emissions from oil and gas operations throughout the state. Accordingly, the Commission directs the Division to provide an annual update on emission growth trends, environmental impacts, modeling and monitoring efforts, the adequacy of emission controls to protect the NAAQS and the health impacts of emissions from the oil and gas sector.

K. December 12, 2008 (Title, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions throughout Regulation Number 7 to address ozone formation in the 8-Hour Ozone Nonattainment Area (NAA), including the 9-county Denver Metropolitan Area and North Front Range (DMA/NFR) NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions are necessary to ensure attainment with the current 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) set at 0.08 parts per million (ppm), and to achieve additional ozone reductions in light of both the new ozone NAAQS set at 0.075 ppm and the Governor's July 27, 2007 directive to proactively and pragmatically reduce ozone levels.

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the area in question expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-hour Ozone NAAQS of 0.08 ppm for ground level ozone. The DMA/NFR includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties. This area is now known as the DMA/NFR NAA.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a revision to the State Implementation Plan (SIP) to the EPA no later than June 30, 2009 that demonstrates attainment of the 8-Hour Ozone NAAQS no later than 2010. The Commission has adopted an Attainment Plan that satisfies this requirement. The Attainment Plan demonstrates attainment with no additional control measures.

Photochemical grid dispersion modeling indicates that without further emission controls, Colorado will attain the 8-hour standard by 2010. The dispersion modeling reflects that Colorado would attain the standard by a narrow margin. Photochemical dispersion modeling analysis is the primary tool used to assess present and future air quality trends, and is required for EPA to approve the state attainment demonstration in the SIP.

In addition, pursuant to EPA guidance, if modeling results indicate that the highest ozone levels will fall between 0.082 and 0.087 ppm, Colorado must conduct a "weight of evidence" analysis and other supplemental analyses in order to corroborate the modeling results. Colorado's model results are within this range, and thus the state has conducted this analysis. The analysis supports the conclusion that Colorado will attain the standard by 2010.

The Commission is also adopting State-only revisions to Regulation Number 7 to further address ozone formation in the DMA/NFR NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions help Colorado make progress toward eventual compliance with the new ozone NAAQS set at 0.075 ppm as well as the Governor's directive to proactively and pragmatically reduce ozone levels.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act ("Act"), C.R.S. § 25-7-101, et seq., specifically, C.R.S. §25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and § 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

These revisions to Regulation Number 7 are part of an overall ozone reduction strategy. The Commission intends that this overall ozone reduction strategy accomplishes six objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the Ozone NAA and across the state, B) revise the control requirements for condensate tanks by a refined system-wide control strategy in the Ozone NAA, C) expand VOC RACT requirements for listed source categories for 100 tpy sources such that all Ozone NAAs are subject to Regulation Number 7's RACT requirements, D) clarify how the RACT requirements in Regulation Numbers 3 and 7 interact in the Ozone NAA, E) improve the Division's inventory of condensate emissions and other relevant sources in the NAA; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

In support of objectives A-D and F, the Commission adopts these revisions to Regulation Number 7 to revise condensate tank regulations, set pneumatic controller regulations, expand RACT applicability and make associated corrections (Regulation Number 7, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F).

In the course of this proceeding, the Division and certain parties supported a compromise proposal regarding the control of condensate tanks. The Commission finds this proposal to be appropriate with certain changes noted herein. The Commission is requiring an increase from 75% to 81% control on a system-wide basis in 2009; to 85% control on a system-wide basis in 2010; and to 90% control on a system-wide basis in 2011 in the 8-Hour Ozone NAA. The Commission is adopting new VOC controls for pneumatic controllers in the 8-Hour Ozone NAA in Regulation Number 7, Section XVIII.

These system-wide control percentages achieve significant ozone precursor reductions in 2009, 2010 and 2011, with emphasis on significant VOC emissions reductions in 2010, during the monitoring period for the attainment demonstration. These revisions will help to ensure that the non-attainment area realizes the necessary reductions during the 2010 attainment year. Further, these revisions are an important step in putting the State on a path towards attaining the 2008 8-Hour ozone standard. A number of parties including the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization supported this proposal to secure VOC reductions from this source at these levels and according to this schedule. The system-wide approach has been approved by the Commission in the past, as well as by EPA in revisions to the State Implementation Plan. The Commission decided to defer decision making on the implementation of a 95% system-wide level of control, given concerns regarding the notable incremental cost associated with control to the equivalent of 2 tpy tanks as well as concerns regarding the flexibility intended to be afforded by a system-wide approach. Tank operators also expressed concern about the loss of incentive to over-control their systems to meet the standard, and the difficulty for small operators to control at the 95% system-wide level at this time.

The proposed control percentages continue to afford flexibility in operations to condensate tank operators, while ensuring attainment of the standard by 2010. Therefore, the Commission is deferring further control for future modeling, air quality analysis, and/or administrative review, whether to control this source in the future at the 95% system-wide control level or through some other approach for purposes of the 2008 8-Hour standard.

The provisions of the compromise proposal, including the commensurate emissions reductions, support the State Implementation Plan's ability to assure attainment and maintenance of the 1997 8-Hour Ozone NAAQS. Inclusion of these provisions enhances the Weight of Evidence demonstration supporting attainment by 2010 pursuant to this State Implementation Plan. The Commission recognizes parties subject to the compromise Regulation Number 7 provisions for condensate tank system-wide emissions reductions concur that these provisions are appropriate for inclusion in the State Implementation Plan.

Further the Commission intends to expand the applicability of RACT requirements to existing, new and modified sources in Ozone NAAs outside of the historic one-hour Ozone NAA or attainment/maintenance area (Regulation Number 7, Sections I and II). The Commission further intends to clarify how the control technology requirements of Regulation Number 7 interact with Regulation 3, Part B, Section II.D.2.

Finally, the Commission intends to make grammatical, typographical, formatting revisions, and other editing revisions throughout Regulation Number 7.

Condensate Tank Emissions Control

Condensate storage tank control requirements in Regulation Number 7, Section XII. are revised by reorganizing the rule, adding/revising definitions, adding monitoring requirements, revising recordkeeping and reporting requirements, and setting additional control requirements for tanks. The current requirements are reorganized by specifying applicability, definitions, general provisions, emissions controls, monitoring, and recordkeeping and reporting sections. The terms new, existing, modified/modification, auto-igniter, and surveillance system were defined.

Tanks serving newly drilled, recompleted or stimulated wells are required to employ air pollution control equipment during the first 90 days of production. After the first 90 calendar days, the control device may be removed. This requirement is designed to address the fact that production, and thus emissions, is at their greatest during the period immediately after drilling, recompletion or stimulation, and the fact that the actual production/emission level is not known prior to drilling, recompletion or stimulation. By requiring controls on all tanks serving newly drilled, recompleted or stimulated wells, the proposed rule significantly reduces emissions during the initial period, while allowing owners and operators to remove control devices afterward, as part of the overall system-wide control regime. All tanks over 2 tpy must participate in the overall system-wide program. Furthermore, since Regulation Number 7's system-wide program is essentially RACT for condensate tanks in the NAA, new and modified 2 tpy or greater condensate tanks (affected by Regulation Number 3 RACT) may also move their control devices after the first 90 days when participating in the overall system-wide control regime, as long as the overall system-wide requirements are being met. Such flexibility is provided as to avoid two regulatory programs: one for tanks that might never be allowed to move their control devices under Regulation Number 3 RACT and one for tanks that would be allowed the flexibility under a system-wide program. Finally, it is the intent of this rule that sources may use their 2 tpy or greater "modified" tanks emissions (i.e., during those tanks' first 90 days of production) in the source's overall system wide calculation. After 90 days, sources must include – whether controlled or otherwise - the 2 tpy or greater "modified" tanks in the overall system-wide calculation. In the case of modified tanks that fall below 2 tpy, it is not the intent of the commission for sources to include these less than 2 tpy tanks in any system-wide calculation. However, sources may use the less than 2 tpy controlled tanks, if necessary to demonstrate system-wide compliance.

The Commission is requiring the installation and operation of auto-igniters for each combustion device. In many cases, condensate tanks are remotely located and unmanned. Auto-igniters will provide greater assurance that the control devices are functioning, under these circumstances. Auto-igniters may be relied on to identify when the pilot is not lit and attempt to relight it, and ensure control operation. The Commission is also requiring surveillance on batteries with uncontrolled emissions greater than 100 tpy. Operators must use surveillance to document the duration of time when the pilot is not lit, and to discover if repairs are necessary to ensure proper control operation. The Commission is targeting this size of battery in order to strike a balance between the need to more carefully monitor performance among the largest batteries, the cost associated with surveillance and the division's capacity to manage the information. The Commission acknowledges that three well operators, Encana, Anadarko and Noble Energy, have agreed to participate with the Division in a pilot program regarding the implementation of electronic surveillance systems.

With regard to recordkeeping and reporting requirements, operators will still record estimated emissions each week (as part of the current Regulation Number 7 requirements) and will report this information to the Division semi-annually. In addition, the Division has revised these requirements so that sources now must keep monthly records throughout the year and provide any of those records within 5 business days of a division request. Further, operators may only use a Division-approved spreadsheet to submit emissions records. Further, a responsible official must now certify the accuracy of the data in the semi-annual reports. This level of recordkeeping and reporting will allow the Division greater capacity to verify compliance and additional availability to work with sources (especially smaller operators). The Commission intends that record-keeping and reporting requirements for surveillance apply only to tanks with uncontrolled emissions greater than 100 tpy.

Controls on 2 Tons Per Year Tanks and Lower

The Commission intends that substantial emissions reductions be achieved from condensate storage tanks and that industry retain the flexibility to decide which tanks to control in order to achieve those reductions. The rule has been revised to subject any condensate storage tank to this rule in the Applicability Section, but stipulates in the Emission Control Section that in order to determine the appropriate system-wide emissions reductions, only two tons per year tanks be considered. In doing this, the Commission intends that tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year or more be considered in determining compliance with the system-wide emissions reductions for the specific ozone non-attainment or attainment maintenance area, and that industry have the flexibility to control smaller tanks in those specific ozone non-attainment or attainment maintenance areas if needed in order to meet the applicable system-wide emissions reductions. For example, if a company owns 20 tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year in a specific ozone non-attainment area, and 15 tanks that emit less than two tons per year, the company would determine its required emission reductions of the production through the 20 two tpy tanks, but be able to control any of the 15 additional less than 2 tpy tanks in order to comply with the system-wide emissions reduction or maintain the desired over control as buffer. However, all tanks controlled in order to comply with the system-wide emissions reduction standard must have filed an APEN and obtained a valid permit in order to be considered as part of the compliance demonstration.

Calendar Weekly and Calendar Monthly Records and Reports

The Commission intends that records and associated reports demonstrating compliance with the weekly emission reduction requirement shall start with the calendar week containing May 1st and end with the calendar week containing September 30th, or other specified dates in the rule. A calendar week begins midnight Sunday morning and ends the following Saturday evening at midnight. Thus, where May 1st falls on any day other than Sunday, the calendar week of May 1st begins on midnight of the preceding Sunday morning. Similarly, the weekly emission reduction requirement applies to the full calendar week that includes September 30th.

So, if September 30th falls somewhere in the middle of a calendar week, the emissions reduction requirement applies to that calendar week in full, beginning midnight Sunday morning and ending the following Saturday evening at midnight.

Consequently, calendar monthly records and associated reports demonstrating compliance with the monthly emission reduction requirement shall apply to midnight the morning of day 1 through midnight the evening of the last day of each specific calendar month.

The Commission intentionally broadened the definition of surveillance to provide that: 1) electronic surveillance is not specifically required, and other means to gather information from remote locations is allowed; and 2) data only had to be gathered on a daily basis. The Commission intends that currently required surveillance need only monitor combustion device flame presence or temperature once every day, in order to balance the need to gather adequate data on combustion device operation with the amount of data to be gathered, handled and processed. The Commission believes this is a fair approach considering that only the largest atmospheric condensate storage tanks (those with actual uncontrolled volatile organic compound emissions equal to or greater than 100 tons per year) are subject to this surveillance requirement.

Finally, the Commission intends that the monitoring be completed to ensure compliance, and has determined that failing to monitor as required, losing monitoring data, and failing to maintain monitoring data should be treated similarly to recordkeeping requirements. Thus, these actions "may be treated by the Division as if the data were not collected."

The Commission intends that system-wide emissions control requirements apply to each specific ozone non-attainment or attainment maintenance area and not collectively to all ozone non-attainment or attainment maintenance areas state-wide. This means that the system-wide emissions control requirements apply specifically to the Ozone Control Area (a.k.a. the Denver Metropolitan Area/North Front Range Ozone Control Area), separately from any future designated ozone non-attainment area. Each new ozone non-attainment area designated in the future shall be subject to the system-wide control requirements by themselves. This is needed to ensure that necessary controls are achieved and maintained in each ozone non-attainment or attainment maintenance area, and that these controls are not removed and offset by system-wide controls in some other ozone non-attainment area.

Pneumatics Emissions Control

This revision establishes new VOC controls for pneumatic controllers in the 8-hour Ozone NAA in Regulation Number 7, Section XVIII. Pneumatic controllers are widely used in the oil and gas industry to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature. Pneumatic controllers of interest are instruments that are actuated using natural gas pressure (of which some natural gas may be bled to the atmosphere from the pneumatic controller and some may be vented from the associated valve). Natural gas-actuated pressure relief devices are not intended to be covered by this rule. There are high-bleed controllers designed to emit more than six standard cubic feet of gas per hour (scfh) to the atmosphere, and low-bleed controllers that emit six scfh or less. Historically, high-bleed controllers have been used.

A 2003 EPA study reported that emissions from pneumatic controllers are collectively one of the largest sources of methane emissions in the natural gas industry. Estimated annual nationwide methane emissions are approximately 31 billion cubic feet (Bcf) from the production sector, 16 Bcf from the processing sector, and 14 Bcf from the transmission sector. As stated, by definition, high-bleed pneumatic controllers emit more than six scfh of natural gas to the atmosphere. The highest bleed rate listed in one source, a table published by the EPA, is 42 cubic feet per hour (cfh). The average bleed rate for high-bleed pneumatic controllers in the NAA is 21 cfh. Natural gas is primarily composed of methane, but also contains other compounds including VOCs and hazardous air pollutants (HAPs).

VOC emissions from pneumatic controllers within the NAA were 24.8 tons per day (tpd) for the 2006 baseline and have been projected to be 31.1 tpd for the 2010 baseline. These emissions represent 14.0

and 15.1 percent of the total VOC emissions from oil and gas sources in the NAA in 2006 and 2010, respectively. Therefore, emission reductions related to this source category have the potential to be significant.

These rules require that most high-bleed controllers must be replaced with the equivalent of low-bleed or better pneumatic controllers by May 1, 2009. There is an exception that allows high-bleed controllers that the Division agrees are necessary for safety purposes. Operators must inspect and maintain in-use high-bleed controllers on a monthly basis. Operators must also keep logs of the number of in-use high-bleed controllers, as well as the reasoning that high-bleed controller remains in place, and the inspection and maintenance of the in-use high-bleed controllers. These revisions further require operators to physically tag the in-use high-bleed controllers to enable the Division to track compliance.

The oil and gas industry has already begun replacing high-bleed controllers with low-bleed controllers, understanding the financial gain of minimizing the bleed rate of pneumatic controllers.

RICE Controls

Reciprocating internal combustion engine (RICE) requirements of Regulation Number 7, Section XVI. applies in what was the early action compact area (now the Ozone NAA). These revisions extend the RICE requirements' applicability to a state-wide basis.

Expand and Clarify RACT Requirements

Regulation Number 7 is revised to expand its application to all subject sources in any Ozone NAA and Attainment/Maintenance Areas. This previously applied to the one-hour attainment/maintenance area nonattainment area. Accordingly, this regulation will apply to some sources that were previously outside of its geographic scope. It is intended that existing sources become subject to previously adopted Control Technique Guidelines (CTGS) or general RACT requirements, and are given time to comply to implement the general RACT requirements. Specifically, existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements. All new or modified sources become subject to these general RACT requirements upon commencing operation after the new ozone non-attainment designation date. This revision is considered a measured approach to ensuring the consistent use of best practices across the NAA as well as reductions in ozone precursors considered necessary to attaining the 8-hour ozone standard.

This revision expands Regulation Number 7's applicability to any Ozone NAA or attainment/maintenance area. This is done intentionally to apply Regulation Number 7 requirements to current as well as any future Ozone NAA or attainment maintenance areas in Colorado.

Additionally, this revision clarifies how the Regulation Number 3 RACT requirements interact with Regulation Number 7. This revision specifies that pursuant to Regulation Number 7, Section II.C. all existing sources that emit 100 tons per year of VOC emissions and that are located in the 8-hour Ozone NAA become subject to RACT.

Further, Regulation Number 7 is currently unclear on whether or not existing sources that are modified become subject to new source requirements. This revision clarifies that existing sources that are modified are subject to the Regulation Number 3, Part B, Section II.D. requirements and are considered to be a new source for the purposes of Regulation Number 7.

This revision also clarifies that the both case-by-case and general RACT requirements of Regulation Number 7, Section II.C. only apply to existing, new and modified sources. For sources at which all air pollution generating activities at that source are already subject to RACT or BACT, the RACT analysis would show that all activities are already subject to RACT or BACT. For any other air pollution generating activities not covered by RACT or BACT, the source would only have to complete a RACT analysis specific to those activities.

Typographical, Grammatical, Formatting and Other Changes

The commission changed the title of Regulation Number 7 to include NOx. An outline of the sections is provided to better understand the contents of Regulation Number 7. Outdated sections are removed (i.e. Section II.F.1. specific to Gates Rubber Company, which is now out of business). Section XII., specific to condensate tanks in the Ozone NAA is reorganized for clarity. One appendix (new Appendix A) is added to provide maps of Ozone NAAs and chronologies of attainment designations, of which certain requirements key off. Finally, sections and appendices are renumbered and formatted as necessary.

Section 110.5 and 110.8 Analysis

Some of these revisions are not intended to be incorporated into Colorado's SIP. To the extent these revisions could be construed to exceed the requirements of federal law, the Commission provides the following additional statement, consistent with C.R.S. § 25-7-110.5(5)(a):

(I) These rules are intended to reduce uncontrolled emissions of ozone precursor pollutants. The rules thereby serve to attain and maintain compliance with the National Ambient Air Quality Standard (NAAQS) for Ozone. However, there are no comparable federal requirements that apply to the sources in question.

(II) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. There is considerable flexibility in meeting the NAAQS. However, there are very limited sources of uncontrolled anthropogenic ozone precursor emissions to target in order to reduce ozone. Consequently, the sources in question, as a significant source of uncontrolled VOCs and NOx, must be targeted in order to attain the standard.

(III) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. The ozone NAAQS was not determined taking into account concerns that are unique to Colorado.

(IV) These rules may prevent or reduce the need for costly retrofit to meet more stringent requirements at a later date. The DMA/NFR non-attainment area has violated the 0.08 ppm ozone NAAQS. Colorado will soon be required to comply with the new ozone NAAQS of 0.075 ppm. Colorado Governor Ritter has directed that Colorado air quality planning agencies implement measures to reduce ozone to a level below the NAAQS. If these rules are not adopted now, it may be necessary to require costlier retrofitting in order to meet the Governor's directive as well as the new NAAQS.

(V) Since there are no applicable federal requirements, there is no timing issue with regard to implementing federal requirements. However, these controls are intended to help the DMA/NFR attain the NAAQS. If the standard is not attained by the 2010 ozone season, the area may face a "moderate" non-attainment designation.

(VI) The adopted rules will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rules establish reasonable equity for sources subject to the rules by providing the same standards for similarly situated sources.

(VIII) If the state rules were not adopted, other sectors may face a disproportionate share of the burden of reducing precursor pollutants.

(IX) There are no corresponding federal requirements.

(X) Demonstrated technology is available to comply. Sources are already using the control devices intended to be used to comply with these rules. However, sources face an additional burden of implementing auto-igniters and surveillance. The Commission anticipates a reasonable degree of delay in securing and installing the technology in question and has accommodated the sources by providing for a reasonable delay for the application of these requirements.

(XI) The adopted rules will reduce VOC and NOx emissions, thereby contributing to the prevention of the formation of ozone through the most cost-effective means available.

(XII) Alternative rules requiring additional controls for other sources would also provide gains toward attaining the ozone NAAQS. However, oil and gas industry members are the largest anthropogenic stationary source of precursor pollutants in the State. A disproportionate benefit to this industry would accrue if their uncontrolled emissions remain at current levels compared to other stationary sources.

(XIII) A no-action alternative may address the ozone NAAQS. Modeling and other analysis suggests that the NAA would attain the standard by 2010 without these rules. However, this analysis suggests that ambient levels of ozone would be very close to the NAAQS. These rules provide more assurance of attaining the ozone NAAQS while also providing for reductions that are necessary to make progress toward the new ozone NAAQS. No action would only delay the necessary reductions.

<u>Further, pursuant to C.R.S. § 25-7-110.8(1), the Commission makes the determination that:</u>

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of ground-level ozone.

(III) Evidence in this record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost effective, provide the regulated community flexibility, and achieve any necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

L. January 7, 2011 (Outline and Sections I. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

Basis and Purpose

The Commission intends that the current Regulation Number 7, Section XVII.E.3.a. identifying technology-based control requirements for existing rich burn reciprocating internal combustion engines (RICE), or rich burn RICE that were constructed or modified prior to February 1, 2009, become a NOx emission control measure that is included as part of the Regional Haze SIP and become federally enforceable upon EPA approval.

The technology-based control requirements of Section XVII.E.3.a. reduce NOx. This proposal only changes the enforceability of these currently state-only requirements such that they become federally enforceable. This proposal does not change emission control, monitoring, recordkeeping or reporting requirements.

The Commission also intends that the following provisions, added in Sections XVII.E.3.a.(i)(a) through (c), will continue to be effective under the Regional Haze SIP. Specifically, these provisions require good air pollution control practices and allow for exemptions from the requirements for existing rich burn RICE. The exemptions apply to any existing rich burn RICE either with uncontrolled actual emissions below permitting thresholds or that is subject to a New Source Performance Standard (NSPS), National Emission Standard for Hazardous Air Pollutants (NESHAP), or Best Available Control Technology (BACT) limit.

Existing lean burn RICE requirements are not incorporated into the Regional Haze SIP, as the associated controls do not reduce NOx or SO2.

Colorado has determined that it is reasonable and appropriate to make these RICE requirements federally enforceable in this first planning period, as part of the state's strategy for addressing reasonable progress towards achieving natural visibility conditions in federal Class I areas.

M. December 20, 2012 (Sections II., XII., and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), Colorado Revised Statutes (C.R.S.) for new and revised regulations.

Basis

Regulation Number 7 is designed to implement substantive regulatory programs authorized under the Colorado Air Pollution Prevention and Control Act (Act) including provisions of the State Implementation Plan (SIP) addressed in C.R.S. Section 25-7-105(1)(a), emission control regulations addressed in C.R.S. Section 25-7-105(1)(b) and authorization of the development of a program for the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) in C.R.S. Section 25-7-301, as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were made to address the U.S. Environmental Protection Agency's ("EPA") partial disapproval of Colorado's ozone SIP.

On August 5, 2011, EPA published the “Approval and Promulgation of State Implementation Plans; State of Colorado; Attainment Demonstration for the 1997 8-Hour Ozone Standard, and Approval of Related Revisions” (76 Fed. Reg. 47443, August 5, 2011). EPA partially approved and partially disapproved revisions to Colorado’s SIP adopted by the Air Quality Control Commission (Commission) in December 2008 and submitted to the EPA in June 2009.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act, C.R.S. Section 25-7-101, et seq., specifically, C.R.S. Section 25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and Section 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

The Commission revised Regulation Number 7 to address the EPA’s partial disapproval of Colorado’s Ozone State Implementation Plan (“SIP’). On August 5, 2011, the EPA issued a final action on Colorado’s June 2009, Ozone SIP submittal, both approving Colorado’s attainment demonstration for the 1997 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) and disapproving specific revisions to Regulation Number 7. 76 Fed. Reg. 47443, August 5, 2011. Specifically, the EPA disapproved both the repeal of Regulation Number 7, Section II.D. and all revisions to Section XII. as adopted by the Commission in December 2008. As a basis for its action, the EPA stated that Colorado demonstrated attainment with the 1997 8-Hour Ozone NAAQS, however Colorado did not adequately provide an anti-backsliding demonstration for the revisions to Regulation Number 7 that were adopted by the AQCC in December 2008, and submitted to the EPA in June 2009.

The Commission intends that these 2012 revisions include both SIP and state-only revisions that address EPA’s partial disapproval of SIP provisions in Sections II.D and XII., and make related state-only revisions to Section XVII. for consistency.

The Commission does not intend that these 2012 revisions add or strengthen emissions control measures of Section II.D., XII. or XVII. at this time. All SIP revisions are intended to specifically address those provisions that EPA included as part of its basis for disapproving revisions to Regulation Number 7.

While the EPA indicated general approval of the concept of the June 2009 SIP submittal, the EPA took exception to some of the details in the SIP revisions, characterized as “deficiencies,” that formed the basis of EPA’s disapproval during the SIP review process. EPA’s objections to the 2009 SIP revisions and the Commission’s responses are summarized as follows:

1. Section II.D. – Alternative Control Plans and Test Methods

   EPA Objection: The EPA objected to the deletion of SIP approved language, allowing for alternative control plans and testing methods.

   Commission Response: The Commission reinstated the SIP approved language.

2. Section XII.C.2. – Emission Factor Calculation Methodology for Condensate Tanks

EPA Objection: The EPA objected to the deletion of the term “gas-condensate-glycol separators” from the emission factor requirements for atmospheric condensate tanks.

Commission Response: The Commission made no revision to the rule text, and instead explained to EPA that this term was used in error as such a separator does not exist. The term used here is a misnomer, which the Commission believes refers to a flash tank located on a glycol dehydration unit, covered by Section XII.H. It is inappropriate to apply emission factor calculation methodology for atmospheric condensate tanks to glycol dehydrators because their emissions vary greatly.

3. Section XII.D.2.a. – System-wide Control Requirements for Condensate Tanks

EPA Objection: The EPA objected to the sunset of the system-wide control requirement in Section XII.D.2.a.(x), which ended the control requirement as of April 30, 2013.

Commission Response: The Commission revised the system-wide control requirements so that the system-wide control requirements do not sunset. Neither the Commission nor the parties to the December 2008 rulemaking intended for the system-wide control to end. The sunset was unintentionally caused when making other revisions to the rule text.

4. Section XII.E.3. – Monitoring Combustion Devices as Control for Condensate Tanks

EPA Objection: The EPA objected to providing a state-only monitoring option (electronic surveillance) as a substitution for the SIP required monitoring of combustion devices being used to control emissions from condensate tanks in accordance with Section XII.

Commission Response: The Commission removed the option of conducting state-only electronic monitoring in lieu of the SIP approved monitoring requirement. This allowance to substitute a SIP required monitoring provision for a state-only monitoring provision was unintentional. None of the sources employing electronic surveillance may use it in place of the SIP approved requirement. If conducted, the electronic surveillance monitoring option must occur in addition to the SIP approved monitoring requirement.

5. Section XII.F.3. – Recordkeeping for Condensate Tanks

EPA Objection: The EPA objected to the lack of SIP required recordkeeping for the control requirement in Section XII.D.1., which requires all condensate tanks at exploration and production sites to be controlled during the first 90 days of well production.

Commission Response: The Commission revised Section XII.D.1. to specify it is state-only. The Commission and parties to the December 2008 rulemaking intended for this first 90-day control requirement to be state-only, which corresponds to the state-only designation on the recordkeeping requirements under Section XII.F.3. Therefore, the Commission made no revision to Section XII.F.3., and instead revised Section XII.D.1. to alleviate this discrepancy.

6. Section XII.F.5. – Recordkeeping and Reporting Exemption for Compressor Stations and Drip Stations

   EPA Objection: The EPA objected to the removal of a SIP approved provision that exempted natural gas compressors or drip stations from recordkeeping and reporting requirements, where total emissions from such facilities are less than 30 tons per year.

   Commission Response: The Commission reinstated the SIP approved 30 tons per year provision.

7. Section XII.G.2. – Control Equipment Requirement for Natural Gas Processing Plants

   EPA Objection: The EPA objected to two aspects of the revisions to this section. The first objection was replacement of the term "APEN de minimus levels" with "greater than or equal to two tons per year." The second objection was inclusion of a rolling 12-month averaging period for the 95% control requirement.

   Commission Response: The Commission made no revision to the replacement of the term "APEN de minimus levels." The Commission explained to the EPA that the associated modeling relied on evaluating condensate tanks with emissions greater than or equal to two tons of volatile organic compounds per year. Therefore, the change in reference does not constitute a lessening of the stringency of the rule. In addition, the Commission removed the rolling 12-month averaging period.

8. Section XII.G.5. Recordkeeping and Reporting for Alternative Compliance Option

   EPA Objection: The EPA objected to the reliance on Title V or construction permits as the location for recordkeeping and reporting requirements for condensate tanks at natural gas compressor or drip stations.

   Commission Response: The Commission revised this section to specify recordkeeping and reporting requirements for condensate tanks at natural gas compressor and drip stations.

9. Section XII.H. Control Requirements for Glycol Dehydrators

   EPA Objection: The EPA stated this entire section lacked clarity and contained redundant language.

   Commission Response: The Commission revised the section in its entirety, while maintaining the intent and applicability of the requirements. Along with this revision, the Commission specified that this control requirement is applicable only to glycol dehydrators with emissions equal to or greater than one ton per year, but that all glycol dehydrators at a stationary source must be included for comparison to the 15 ton per year threshold. The term stationary source is defined in the Common Provisions. Further, the Commission revised the provision to include emission calculation methodology requirements in Section XII. H.

Items 1-9 are all SIP revisions.

In addition, the Commission is also revising the state-only Section XVII.D. for consistency with the 2012 SIP revisions. The Commission does not intend that this state-only revision change the applicability of the control requirements for glycol natural gas dehydrators. Finally, the Commission made typographical, grammatical, and formatting revisions, as necessary.

N. February 23, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 CFR Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result and further addresses the volatile organic compound ("VOC"), an ozone precursor, and other hydrocarbon emissions, such as methane, from the oil and gas sector.

The Commission supports the EPA's development of NSPS OOOO and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. First, the Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"); it is likely that EPA will lower the ozone NAAQS in the near future, potentially expanding Colorado's nonattainment area; and Division air monitors and other sampling indicate elevated levels of oil and gas related air emissions in oil and gas development areas. Second, Colorado has seen substantial growth of oil and gas development in recent years, which is a significant source of VOC emissions, and expects that growth to continue in the foreseeable future. In particular, oil and gas storage tanks contribute significantly to the VOC emissions from oil and gas development. Further, oil and gas operations also emit methane, a negligibly reactive ozone precursor and potent greenhouse gas. Third, oil and gas operators have had difficulty meeting the current 95% control requirements in Regulation Number 7 established for condensate tanks in 2004 and 2006 due to "flash" emissions. Fourth, improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs and methane in a cost-effective manner. These technologies and practices include, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras).

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both SIP and state-only requirements. During the rulemaking process, various parties provided extensive evidence concerning whether the proposed revisions, in particular the STEM and LDAR requirements, should apply either statewide or only in the ozone nonattainment area. Based upon careful consideration of all the evidence provided during the rulemaking, the Commission determined it was appropriate to apply the proposed requirements statewide. Further, in addition to the extensive evidence concerning the benefits of statewide hydrocarbon emission reductions, the Commission believes that the tiered and phased nature of many of the requirements properly focuses on emissions. Under this tiered approach, lower emitting sources such as marginal, stripper, and coal bed methane wells will appropriately be subject to less rigorous and costly requirements. In addition, evidence in the rulemaking record and testimony of industry members supports the conclusion that the rules can be effectively implemented. Accordingly, the Commission concludes that the proposed rules are technologically feasible and cost-effective. Moreover, because these revisions apply on a state-wide, state-only basis, and are not a part of Colorado's SIP, the Commission, the Division, and stakeholders have the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and natural gas compressor stations. The Commission expands existing oil and gas control requirements and establishes additional monitoring, recordkeeping, and reporting requirements. For example, the revisions increase control requirements and improve capture efficiency requirements for oil and gas storage tanks. The Commission also seeks to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells and wells undergoing maintenance and during liquids unloading events. The Commission also expands control requirements for pneumatic devices and glycol natural gas dehydrators. The Commission believes that this combination of revisions is appropriate to complement the full adoption of NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, remove the off-ramp for condensate tanks if subject to a NSPS, MACT, or BACT, and remove the leak detection and repair requirements off-ramp for glycol natural gas dehydrators and internal combustion engines if subject to a NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;
- Limit venting and establish a storage tank emissions monitoring system ("STEM"), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol natural gas dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for natural gas compressor stations and well production facilities in Section XVII.F.;

- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance and liquids unloading in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVIII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Joint Applicability of NSPS OOOO and Regulation Number 7, Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates some overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with six (6) tons per year ("tpy") of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. It is the Commission's intent that compliance with Regulation Number 7, Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions from storage vessels under NSPS OOOO. In those limited cases where storage tanks are subject to both NSPS OOOO and Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring. However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy, the equivalent of the NSPS OOOO six (6) tpy VOC on a controlled actual basis. While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary and intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT control requirement to avoid having to comply with Section XVII.

It is also possible for glycol natural gas dehydrators and internal combustion engines to be subject to both federal and Regulation Number 7, Section XVII. leak detection and repair requirements. NESHAP HH and HHH require glycol natural gas dehydrators at major sources of hazardous air pollutants ("HAP") that utilize a closed-vent system to conduct annual visual inspections for leaks and defects that could result in air emissions. NESHAP HH and HHH also require detected leaks and defects be repaired within fifteen days, as long as it is technically feasible to do so without a shutdown. NESHAP HH also requires triethylene glycol ("TEG") natural gas dehydrators located at area sources of HAPs that utilize a closed-vent system to conduct annual visual inspections. However, the revisions to Regulation Number 7 require more frequent inspections of all types of glycol natural gas dehydrators at all facilities, resulting in more emissions reductions than NESHAP HH and HHH. Therefore, the Commission believes joint applicability concerning leak detection and repair requirements is necessary.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC and other hydrocarbon emissions, such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of greater than or equal to one (1) minute during a fifteen (15) minute time period, pursuant to EPA Method 22. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. The regulated community may, alternatively, immediately shut-in the equipment to investigate the cause for smoke and perform repairs. While the presence of visible emissions constitutes a violation of the rules, the Commission recognizes that there may be instances where visible emissions occur notwithstanding the owner or operator's best efforts, such as when an upset or malfunction occurs. Accordingly, the Division should consider the owner or operator's efforts and whether the visible emissions resulted from factors outside the owner or operator's control in determining how to best enforce this requirement.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Approved instrument monitoring method" ("AIMM") means the methods and technologies utilized for monitoring storage tanks and components at well production facilities and natural gas compressor stations. The instrument being used for AIMM inspections must be capable of measuring hydrocarbon compounds at the applicable leak definition concentration specified in the revisions, and calibrated as appropriate. See EPA Method 21 at 6.0. In addition, while the definition lists EPA Method 21 and IR cameras, the Commission does not intend to limit industry to only EPA Method 21 and IR cameras as the Division may approve the use of additional monitoring devices and methods.

"Component" excludes compressor seals and open-ended valves and lines, which are defined separately, because they are designed to leak and are better addressed with equipment specific work practices, also included separately. Based on concerns that the requirements for small reciprocating compressors at well production facilities may not be cost-effective, the adopted work practices for reciprocating compressors are limited to reciprocating compressors located at natural gas compressor stations. Nevertheless, there is an issue as to whether compressors at well production facilities are a significant source of emissions. The Commission, therefore, directs the Division to investigate whether reciprocating compressors at well production facilities are a significant source of emissions, and if so, whether there may be appropriate, cost-effective work practices to reduce fugitive emissions from reciprocating compressors at well production facilities. The Commission further directs the Division to brief the Commission on this investigation in March, 2015.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both COGCC and Commission requirements.

“Natural gas compressor stations” are subject to leak detection and repair requirements. This definition is meant to exclude compressors at well production facilities and gas processing plants. This definition is also meant to exclude natural gas compressor stations that are downstream of the natural gas processing plant at this time.

“Normal operation” is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of “malfunction” as set forth in the Common Provision regulations.

“Storage tank,” means a single storage tank or a storage tank battery if the storage tanks are manifolded together. In recent years, it has become more common for multiple storage tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of “storage tank,” the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery. The Commission’s definition, and Colorado’s approach to emissions reporting and permitting for storage tanks, differs from EPA’s definition of “storage vessel” and the description of an affected storage vessel facility in NSPS OOOO because EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. The Commission intends to maintain this distinction and, therefore, deletes the previously used definition of “atmospheric condensate storage tank” and creates a new definition of “storage tank” which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

“Well production facilities” are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The “owned, operated, or leased” qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from “well production facility” and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells.

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas operations, including those below control thresholds or even below Regulation Number 3 APEN and permitting thresholds, adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;

- Inspecting and repairing seals on thief hatches, access points, or other openings of storage tanks;

- Initiating timely action to address leaks or unpermitted emissions; and

- Maintaining equipment and the facility in good operating condition.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. The Commission intends these revisions to address venting emissions from storage tank thief hatches, pressure relief valves, or other access points during normal operations. Access points are not limited to points of entry of liquids or gas into the storage tank but include any route from which emissions can escape. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices and that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. The Commission does not intend to increase risk or compromise safety of personnel and equipment. However, inadequate design of a storage tank emissions capture system is not a legitimate reason for venting.

Therefore, the Commission intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to owners or operators, provided that the owners or operators demonstrate that the elements of the malfunction defense have been met. The Commission intends that the burden remain on the owner or operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2. The Commission further recognizes that meeting the no venting requirement may be challenging in some cases, and accordingly has adopted additional provisions requiring owners and operators to develop a STEM plan to help ensure compliance. In some cases, development and implementation of the STEM plan may be an iterative process involving ongoing improvements before continuous compliance with the no venting standard is achieved. With this in the mind, the Division should consider the efforts of owners and operators in developing and implementing their STEM plan as part of the Division’s assessment about how best to enforce the no venting requirement.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and natural gas compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered by the owner or operator or the Division inspector pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if a leak is identified and the owner or operator is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the owner or operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners or operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tanks Controls (Section XVII.C.)

EPA established a six (6) tpy VOC threshold on a controlled actual emissions basis for applying storage vessel controls. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for applying reporting, permitting, and control requirements. This means that the EPA’s six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control equipment may be removed if: (1) the storage tank (including manifolded tanks) emissions fall below the uncontrolled actual six (6) tpy threshold, on a rolling twelve-month basis; and (2) those controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the uncontrolled actual six (6) tpy threshold on a rolling twelve-month basis, air pollution control equipment must be installed within sixty (60) days of discovery of the increase.

The Commission does not intend for the storage tank control, or related, requirements to apply to frac tanks that are located at a well production facility for less than 180 consecutive days.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used the device must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Audio, Visual, Olfactory ("AVO") and Visual Inspections (Section XVII.C.)

The Commission intends that owners and operators of subject storage tanks (including storage tanks during the first ninety (90) days of production and storage tanks containing only stabilized liquids) conduct applicable AVO and visual inspections for venting or leaking. Visual inspections are in addition to AVO monitoring and require further inspections of the storage tank and associated equipment, such as thief hatches and air pollution control equipment. These inspections are not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO and visual inspection, and indicates the frequency at which inspection is required.

Storage Tank Emission Management System ("STEM") Plan, Monitoring, and Recordkeeping (Section XVII.C.)

Owners and operators of storage tanks with uncontrolled actual emissions equal to or greater than six (6) tpy must develop, certify, and implement a STEM plan designed to ensure compliance with the "without venting" requirement of Section XVII.C.2., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies, monitoring, maintenance, and operational practices to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility to develop STEM plans on an individual basis for each storage tank or for multiple storage tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review. Owners and operators of storage tanks controlled during the first ninety (90) days of production or containing only stabilized liquids are not required to develop and implement a STEM plan. However, owners or operators of such storage tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include, but is not limited to, the following elements:

- A monitoring strategy including, at a minimum, the applicable inspection frequencies and methodologies;

- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the owner or operator to demonstrate the quality and achievements of the STEM plan;

- The calibration methodology and schedule for emission detection equipment used in the monitoring;

- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;

- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;

- A procedure to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and

- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

In addition to AVO and visual inspections for storage tanks, STEM plans must include AIMM inspections on a frequency schedule that is tied to the uncontrolled actual VOC emissions from the storage tank. The Commission intends that the AIMM inspection satisfy any simultaneous AVO and visual inspection requirement.

The STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of applicable monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Unsafe, Difficult, or Inaccessible to Monitor (Sections XVII.C. and XVII.F.)

The Commission does not intend to require owners or operators to conduct either AVO or AIMM inspections of unsafe, difficult, or inaccessible components or storage tanks and associated equipment. The Commission acknowledges that, in limited circumstances, unsafe to monitor may include unsafe weather or travel conditions. However, in those limited circumstances, the Commission expects the owner or operator to resume monitoring once the weather or travel conditions cease to be unsafe. Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season.

Glycol Natural Gas Dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. This revision requires that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of six (6) tpy or greater be controlled with air pollution control equipment achieving at least a 95% reduction. This revision also requires that existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled if the dehydrator is located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations.

The Commission does not intend to apply this proximity requirement to the glycol natural gas dehydrator owner or operator's buildings, where public access to the building is also restricted. Further, because glycol natural gas dehydrators are different and unique sources, a similar proximity requirement for storage tanks is not appropriate at this time as storage tanks are more appropriately addressed based on emission thresholds.

This revision also requires that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. The leak detection and repair program more broadly targets leaks from components at natural gas compressor stations and well production facilities, even if such facilities do not include storage tanks. In contrast, STEM targets venting from storage tanks. The use of an AIMM as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may have lower emissions and may need additional time to comply. Owners or operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor. Owners or operators also have flexibility in timing the AVO and AIMM inspections to coordinate overlapping AVO and AIMM inspections, as well as inspections of facilities in the same area or on the same inspection frequency. The Commission intends that the AIMM inspection satisfy any simultaneous AVO inspection requirement. However, the Commission expects that owners and operators will also utilize this flexibility to ensure that inspections are appropriately spaced on the frequency schedule (e.g. quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Commission distinguished between new and existing well production facilities by utilizing an October 1, 2014, commenced construction date and created an inspection phase-in schedule for existing facilities.

The Commission also distinguished the emissions thresholds for determining inspection frequencies for well production facilities with storage tanks and well production facilities without storage tanks. For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on "facility emissions." The Commission has determined that "facility emissions" means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.

The Commission has defined a leak requiring repair in a manner that is dependent on the monitoring methodology. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identify the emission rate. Similarly, while IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in selecting a leak detection methodology.

If EPA Method 21 is utilized, the Commission set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing natural gas compressor stations and

500 ppm for new (constructed after May 1, 2014) natural gas compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is utilized, a leak is any detectable emission not associated with normal equipment operation (e.g. the acceptable level of leaks from a component designed to leak). These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources.

Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO identifies leaks at natural gas processing plants at 500 ppm. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices. Further, the Commission finds that the repair deadlines set forth in Section XVII.F.7. provide flexibility for operational differences, including the potential range of leaks and degrees of repair difficulty that may be encountered.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country.

The Commission expects that owners and operators will remonitor leaks requiring repair with either the approved instrument monitoring method the owner or operator used to identify the leak or any method approved for remonitoring of leaks under EPA Method 21.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in permits existing as of the promulgation date of the revisions. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and owners and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

During the rulemaking, several parties requested more stringent requirements for all oil and gas operations located within 1,320 feet of a building unit or designated outside activity area. Residents living within close proximity to oil and gas operations, particularly those living within 1,320 feet of oil and gas operations, may understandably have heightened concerns regarding potential impacts of emissions from such facilities. It is the Commission’s understanding that some oil and gas owners and operators implement practices beyond what is currently required under state law in order to minimize emissions and otherwise be good neighbors, including conducting increased site inspections. The Commission supports such practices.

Also during the rulemaking, various parties provided extensive evidence concerning the frequency of instrument monitoring method inspections, the timing of leak repair, and the costs and benefits associated with more or less frequent monitoring and repair. The Commission recognizes that additional information would benefit the Commission, Division, industry, and other stakeholders and therefore encourages the Division to work with energy companies, to evaluate the comparative effectiveness of various kinds of instrument based monitoring methods and program designs at a range of types, sizes, and frequencies at well production facilities and natural gas compressor stations.

The Commission also encourages the Division to work with industry and other stakeholders to evaluate emissions from and potential control strategies for downstream natural gas compressor stations and intermittent pneumatic controllers.

Lastly, several parties to the rulemaking requested greater transparency and public access to air quality information associated with oil and gas development. In particular, a coalition of local community organizations requested that owner and operators' annual reports as required by these rules be posted on the Division's website. The Commission believes these reports will provide important information when reviewing the efficacy of the inspection and maintenance program, as well as valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make this information available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. In addition, the Commission requests an annual briefing on these regulations. Such briefing will assist the Commission and interested stakeholders to understand the data and implementation issues relating to this new program, as well as other initiatives covered in this rulemaking. The Commission believes that this information would also be valuable to all parties.

Well Maintenance and Liquids Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well maintenance and well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading emissions are estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008, rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. However, the Commission does not intend to expand the pneumatic device requirements to intermittent pneumatic controllers at this time. Further, while the use of low-bleed pneumatic controllers will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources.

However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is only requiring the use of no-bleed pneumatic controllers at facilities that are connected to the electric grid, using electricity to power equipment, and where technically and economically feasible.

Additional Considerations

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Sections XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) The revisions to Regulation Number 7 address VOC and other hydrocarbon emissions from oil and gas facilities, including storage tanks, glycol natural gas dehydrators, pneumatic controllers, well production facilities, and natural gas compressor stations. In addition to NSPS OOOO, NSPS Kb, and NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks, glycol natural gas dehydrators, leaking components, and pneumatic controllers, and address more hydrocarbon emissions. For example, the Regulation Number 7 revisions address more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to TEG dehydrators. Similarly, the Regulation Number 7 revisions address more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. In addition, the Regulation Number 7 revisions address more component leaks than the major source provisions of NESHAP HH, as well as NSPS KKK, which has a 10,000 ppm leak threshold and only applies at natural gas processing plants.

Compared to NSPS OOOO, the revisions to Regulation Number 7 will apply a low- or no-bleed control requirement to more pneumatic controllers because NSPS OOOO only requires zero bleed pneumatic controllers at natural gas processing plants, while the Regulation Number 7 revisions no-bleed provision applies to all facilities. The revisions to Regulation Number 7 will also require a leak detection and repair program for more oil and gas operations because NSPS OOOO only requires leak detection and repair for natural gas processing plants, AVO inspections for storage vessels with controlled actual emissions greater than six (6) tpy, and annual visual inspections for leaks for subject centrifugal compressors. In contrast, the revisions to Regulation Number 7 require a leak detection and repair program for all components at all well production facilities and natural gas compressor stations. Further, the revisions to Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to further address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

(II) NSPS OOOO, and the other federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, which may be used to avoid NSPS OOOO applicability.

(III) Other federal requirements do not specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. Specifically, during the development of NSPS OOOO, Colorado submitted comments regarding, among other things, concerns with the storage vessel definition, storage vessel control requirements, and lack of leak detection and repair requirements. Colorado's concerns were not fully addressed in NSPS OOOO, therefore, the Commission believes the revisions to Regulation Number 7 are necessary to: (a) address hydrocarbon emissions in a more comprehensive manner; (b) address oil and gas operations and equipment at lower thresholds than NSPS OOOO thresholds, yet that collectively have significant VOC and other hydrocarbon emissions in Colorado; (c) address venting of emissions from storage tanks at oil and gas facilities caused primarily by over pressurization; and (d) address leaks of fugitive hydrocarbon emissions, particularly from well production facilities and natural gas compressor stations.

(IV) Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for costlier retrofits at a later date. Colorado may be required to comply with a lower ozone NAAQS in the near future and the Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS, while other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. The revised rules are proactive and intended to reduce ozone levels now by utilizing controls and techniques already being used by some Colorado oil and gas operators, or that are readily available.

(V) Adoption of these revisions at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

(VI) The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while utilizing many of the technologies and practices set forth in these revisions.

(VII) The revisions to Regulation Number 7 establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector. Furthermore, the application of the Regulation Number 7 revisions to oil and gas owners and operators regardless of location in the ozone nonattainment or attainment areas is equitable because the nonattainment area is not the only area in Colorado with ozone issues. For example, the Rangely monitor in western Colorado shows violations of the 2008 ozone standard and existing modeling shows that either the nonattainment area has increased its contribution to background ozone or ozone concentrations in the attainment area flowing into the nonattainment area have increased. Notably, the Division's inventory shows that the oil and gas industry contributes more than 50% of the VOC emissions outside the nonattainment area. This monitoring, modeling, and inventory data, considered with the likelihood of a lower ozone NAAQS and the expected growth of the oil and gas sector state-wide, supports the application of the Regulation Number 7 revisions to oil and gas sources in both the nonattainment and attainment areas.

(VIII) The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions. In reductions must come from other operations or sectors at this time, the cost effectiveness would decrease because these revisions reduce emissions from the most significant contributors to VOC emissions and costs will be higher for less emissions reductions from less significant contributors.

(IX) The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO (e.g. storage vessels emitting 120 tpy uncontrolled actual VOC emissions) or NESHAP HH and HHH (e.g. glycol natural gas dehydrators at major sources of HAPs and TEG glycol natural gas dehydrators at area sources of HAPs) and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to ensure compliance with and document the effectiveness of the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the requirements for auto-igniters and pneumatic controllers. In addition, oil and gas owners and operators are already using many of the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides owners and operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the revisions provide for Division approved extensions to compliance.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The reductions of other hydrocarbon emissions, such as methane, add to the already cost-effective and appropriate emission reduction requirements.

(XII) Alternative rules, such as the alternative proposals provided by several parties during the rulemaking process, requiring differing or additional controls for oil and gas facilities could also provide reductions in hydrocarbon emissions. The Commission could have adopted some or all of the proposed revisions or proposed alternatives. However, the proposed revisions to Regulation Number 7 were developed during a lengthy stakeholder process and provided a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. The alternative proposals provided during the rulemaking process were primarily either more or less stringent versions of the proposed revisions, further illustrating the balanced approach of the proposed revisions. Furthermore, a no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursor pollutants, necessary for reducing ozone in Colorado.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.

(III) Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(VI) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

O. November 17, 2016 (Sections I., X., XII., XIII., XVI., XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data. Due to the reclassification, additional planning requirements were triggered, including the requirement to submit revisions to the State Implementation Plan ("SIP") that address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA Section 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)).

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive state implementation plan that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 25-7-109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions. Separately, EPA had expressed concerns with approving previous Regulation Number 7 revisions related to oil and gas control requirements and submitted in 2009 and 2013 for inclusion in Colorado's ozone SIP.

In response to these related but separate issues, the Commission revised Regulation Number 7 to strengthen Colorado's ozone SIP; and include reasonably available control technology ("RACT") requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of volatile organic compounds ("VOC") or nitrogen oxides ("NOx"). More specifically, the Commission revised the applicability of Regulation Number 7 in Section I.A.1.; included the existing combustion device auto-igniter requirements in Section XII.C.1.e. and XII.E.2. in Colorado's ozone SIP; included existing audio, visual, olfactory ("AVO") storage tank inspection requirements for condensate storage tanks in Colorado's ozone SIP in Section XII.E.4.e.; added requirements for lithographic and letterpress printing in Section XIII.B.; added requirements for industrial cleaning solvents in Section X.E.; and added requirements for major sources in Sections XVI. and XIX.

Apart from the Moderate nonattainment area ozone SIP, the Commission revised Regulation Number 7 to address EPA's monitoring, recordkeeping, reporting, and other concerns with previously submitted Regulation Number 7 revisions. The Commission updated federal rule references for natural gas processing plants in Section XII.G.1.; renumbered the current Sections XII.G.5. and XII.G.6. under Section XII.I.; added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in Sections XII.H.5. and XII.H.6.; and addressed other EPA concerns in Sections XII.C.1.c., XII.C.1.d., XII.C.2.a.(ii)(B), XII.E.3., and XII.H.4.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Ozone reclassification SIP revisions

8-hour ozone control area

All provisions of Regulation Number 7 currently apply to the Denver 1-hour ozone nonattainment and attainment/maintenance area. The 1-hour ozone area does not include all of Adams and Arapahoe counties or the portions of Larimer and Weld counties included in the 8-hour ozone control hour. Therefore, to ensure that all sources in the 8-hour ozone nonattainment area are subject to applicable RACT requirements in Regulation Number 7 on a federally enforceable basis, the Commission revised Regulation Number 7, Section I.A.1.a. to state that all provisions apply to both the 1-hour and 8-hour ozone areas. The Commission intends that provisions clearly marked "state-only" continue to be enforceable only on a state-only basis, and are not included in the SIP.

Auto-igniter and storage tank AVO

Regulation Number 7, Section XII.C.1.e. includes auto-igniter requirements for combustion devices used to control emissions of VOCs. Pursuant to Section XII.E., the auto-igniter must be inspected weekly to ensure it is properly functioning. Prior to the revision, these requirements were "state-only". The Commission revised these provisions to include the auto-igniter installation, operation, and monitoring requirements in the SIP.

Regulation Number 7, Section XII.E. includes requirements for owners or operators of condensate storage tanks subject to Section XII.D. to inspect combustion devices, vapor recovery units, control devices, and thief hatches. These are SIP requirements. Regulation Number 7, Section XVII.C.1.d. also requires of owners or operators of storage tanks subject to Section XVII. to conduct AVO and additional visual inspection at the same frequency as liquids load-out. The requirements of Section XVI.C.1.d. are enforceable on a "state-only" basis. The Commission revised Section XII. to include in the SIP, the requirement that owners and operators conduct AVO inspections of condensate storage tanks with uncontrolled actual VOC emissions of 6 tons per year ("tpy") or greater, making them federally enforceable.

Lithographic and letterpress printing RACT

Pursuant to CAA Section 182(b), Colorado's ozone SIP must provide for implementation of RACT at sources of VOC for which EPA has issued a Control Technique Guideline ("CTG"). EPA's Offset Lithographic Printing and Letterpress Printing CTG ("Printing CTG") addresses VOC emissions from the use of fountain solutions, cleaning materials, and inks at lithographic and letterpress printing operations. The Printing CTG recommends controlling VOC emissions from heatset printing with dryer emissions of at least 25 tpy of VOC from heatset inks with add-on control technology. The Printing CTG recommends controlling VOC emissions from cleaning materials and fountain solutions at printing operations with facility emissions equal to or greater than 15 lb/day by limiting the VOC content of cleaning materials and fountain solutions. The Printing CTG also recommends work practices for printing operations with facility emissions equal to or greater than 15 lb/day.

Colorado has sources in the ozone nonattainment area in this CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included these requirements in Section XIII.B. as RACT for these sources. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy. This is roughly equivalent to the 15lbs/day threshold recommended in the Printing CTG. Based on the Printing CTG, the Commission added language to Section XIII.B.1.b. clarifying that fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses are considered part of the printing process and are not subject to the surface coating or industrial cleaning solvent requirements in Regulation Number 7. With respect to the compliance threshold for Section XIII.B., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. Only emissions from the printing operation and cleaning thereof should be considered in determining if emissions exceed 3 tpy.

The Commission included additional work practices, a VOC content limit for inks and monitoring, recordkeeping and performance testing requirements that are not specified in the Printing CTG but are intended to correspond to current permit requirements and ensure the enforceability of the requirements. With respect to the work practice requirements contained in Section XIII.B.1.c., the Commission applied these requirements to all lithographic and letterpress printing operations, regardless of potential or actual VOC emissions, because they are minimally burdensome, good housekeeping requirements that reduce emissions and correspond to current permit requirements. With respect to the VOC content limit for inks, the Commission included a 40% limit for heatset web offset and heatset web letterpress printing operations that require higher VOC content ink, and a 30% limit for all other lithographic and letterpress printing operations that are commonly already using low VOC inks. Compliance with the VOC content requirement for inks is demonstrated using a weighted average which takes into account the amount of the different inks used and their respective VOC contents.

For consistency with the Printing CTG, cleaning solutions are subject to VOC content or vapor pressure requirements, except that sources using less than 110 gallons of non-compliant cleaning materials per calendar year are exempt from the VOC content or vapor pressure requirements. Larger heatset printing operations, whose maximum allowable emissions before controls from petroleum inks are 25 tpy VOC or more, are subject to a control requirement (not capture and control). Printing operations' emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Industrial cleaning solvents RACT

EPA's CTG for Industrial Cleaning Solvent ("Cleaning Solvent CTG") addresses solvent use in cleaning operations such as spray gun cleaning, spray booth cleaning, large manufactured components cleaning, parts cleaning, equipment cleaning, line cleaning, floor cleaning, tank cleaning, and small manufactured components cleaning. The Cleaning Solvent CTG applies to facilities with VOC emissions from the use of industrial cleaning solvents equal to or greater than 15 lb/day of VOC. The Cleaning Solvent CTG recommends a cleaning solvent VOC content limit and work practices.

Colorado has sources in the ozone nonattainment area in this Cleaning Solvent CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included requirements in Section X.E. as RACT. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy on a calendar basis. This is roughly equivalent to the 15lbs/day threshold recommended in the CTG. The Commission intended for the term "industrial cleaning solvent operation" to be broad and apply to a wide range of work areas where manufacturing or repair activities are performed, but not to residential or janitorial cleaning.

The Commission included language to clarify that VOC emissions that are exempt from the industrial cleaning solvent rule do not count toward this 3 tpy threshold. Therefore, when determining whether a facility meets the applicability threshold of 3 tpy, a source should include facility-wide emissions from all industrial cleaning solvent operations and subtract those emissions that are exempt under Section X.E.4. In adopting the VOC content limit in Section X.E.1.a. and the vapor pressure limit in Section X.E.1.b., the Commission intended for these to be straight, as-applied limits for all industrial cleaning solvents used and not a weighted average. Additionally, in adopting the 90% control efficiency compliance option in Section X.E.1.c., the Commission did not intend for this control efficiency to include capture efficiency. The Commission acknowledged that capture efficiency may be lower than the control efficiency because industrial cleaning solvents are often used over large industrial complexes and result in relatively small VOC emissions.

With respect to the compliance threshold for Section X., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. The Commission also included monitoring, recordkeeping and reporting requirements that are not specified in the Cleaning Solvent CTG but are intended to align with current permit recordkeeping requirements and ensure the enforceability of the requirements.

The Commission included language in Section X.E.4.a.(ii) providing that industrial cleaning solvent operations subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT are exempt from the requirements of Section X. This provision was included so as not to subject sources to overlapping, duplicative, or contradictory RACT requirements. Therefore, if an industrial cleaning solvent operation is subject to a work practice or emission control requirement contained in another, federally approved section of Regulation Number 7, including but not limited to Sections IX. (surface coating operations), X.B. through X.D. (solvent cold-cleaners, non-conveyorized degreasers, and conveyorized degreasers), and XIII. (graphic arts and printing), then that operation would not also be subject to the requirements of Section X.E.4. However, this provision is not intended to exempt an industrial cleaning solvent operation from Section X. when the operation is subject to the restriction on disposal of VOCs by evaporation or spillage contained in to Section V.A. (and RACT is determined to be nothing). Therefore, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be nothing, the operator must comply with Section X. Conversely, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be a work practice or emission control requirement, then the operation is exempt from Section X. Lastly, the Commission adopted additional exemptions recommended in the Cleaning Solvent CTG in Section X.E.4.b. as well as an alternative compliance option for area source aerospace facilities in Section X.E.4.c. due to the unique solvent cleaning needs of those source categories.

Control requirements do not account for capture and control. General industrial solvent use emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Major VOC and NOx source RACT

Colorado has major sources of VOC or NOx (sources that emit or have the potential to emit greater than 100 tpy) in the DMNFR. While many of these sources are currently subject to regulatory RACT requirements in Colorado's SIP, some of the sources or emissions points are subject to RACT requirements in federally enforceable permits or New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado is submitting a SIP revision to include provisions requiring the implementation of RACT for major sources of NOx or VOC in the DMNFR. Therefore, the Commission included a work practice for combustion equipment at major sources of NOx emissions in Section XVI., a requirement for specific major sources to provide RACT analyses to the Division in Section XIX.B., and incorporated by reference applicable requirements of a NSPS or NESHAP in Sections XIX.C-G.

Specifically, the Commission adopted a combustion process adjustment requirement for individual pieces of combustion equipment at major sources of NOx in Section XVI.D., expanding on work practices currently required in federal NESHAP. The combustion process adjustment was modeled after NESHAP DDDDD, which applies to boilers and process heaters at major HAP sources, and NESHAP ZZZZ, which establishes various requirements for stationary reciprocating internal combustion engines. Section XVI.D. is intended to apply to some equipment that is not subject to work practices under the NESHAPs (e.g., natural gas fired boilers at area sources of HAPs) that have uncontrolled actual NOx emissions (annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice without consideration of any emission control equipment or procedures) equal to or greater than 5 tpy. The Commission intended major NOx sources to use the most recent APEN submitted to the Division as of January 1, 2017, to determine whether the combustion equipment is subject to the requirement to conduct an initial combustion process adjustment by April 1, 2017, or alternatively document reliance on an allowed, alternative adjustment. Subsequent determinations will be based on the most recent APEN submitted to the Division as of the year the combustion equipment may be subject to the combustion process adjustment requirements (e.g., most recent APEN submitted to the Division as of January 1, 2018, to determine whether a combustion process adjustment is required in 2018). In addition to the specific adjustment requirements, the Commission intended owners and operators to operate and maintain subject equipment consistent with manufacturer specifications or best combustion engineering practices.

The Commission also established RACT requirements for emission points at major sources of VOC or NOx in the DMNFR area in Section XIX. In Section XIX.A., the Commission listed all major sources of VOC or NOx at the time of adoption of the Moderate nonattainment area RACT SIP. The Commission determined that not all emission points above permitting thresholds at major sources were necessarily subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP. Therefore, in Sections XIX.C. through XIX.G., the Commission incorporated federal NSPS or NESHAP requirements, including monitoring, recordkeeping, and reporting requirements, for some sources to further satisfy Colorado's RACT obligation for Colorado's major VOC and NOx sources. The Commission acknowledges concerns over potential EPA revisions to NSPS and NESHAP incorporated by reference in Sections XIX.C. through XIX.G., and intended that sources comply with applicable requirements in the most up-to-date version of the federal rule, or alternative requirements approved by EPA in accordance with the NSPS or NESHAP. The Commission also directs the Division to initiate efforts to update the incorporation by reference in the SIP, as necessary and with all due diligence. Sources identified in Section XIX.A. but not specifically included in Sections XIX.B. through XIX.G., were determined to be subject to other, existing regulatory RACT requirements in Colorado's SIP (see the Moderate ozone SIP revision, RACT Chapter 6 and the Technical Support Document for Reasonably Available Control Technology for Major Sources for additional detail). Concerning major sources or source emission points not subject to other, existing regulatory RACT requirements in Colorado's SIP or specified in Sections XIX.C. through XIX.G., the Commission required owners or operators to submit RACT analyses for the facility or specific emission points to the Division by December 31, 2017. The RACT analyses should identify potential options to reduce NOx and/or VOC emissions from the facility or emission point(s), propose RACT for that facility or point, propose associated monitoring, propose a schedule for implementation, and include economic and technical information showing why the RACT proposal is RACT for the particular facility or point. These RACT analyses are not to be limited by a January 1, 2017, implementation date.

CoorsTek submitted a permit application to limit permitted emissions of VOC below 100 tpy. Metro Wastewater Reclamation District submitted an application for minor modification to its Title V permit to correct inconsistencies and remove obsolete limits, which lowered the combined Metro Wastewater/Suez Denver Metro permitted NOx emission limit below 100 tpy. Consequently, the Commission determined that the facilities no longer met the definition of a major source, and therefore were not included in Section XIX. Should either source fail to obtain such federally enforceable permits by July 1, 2018, the Commission directs the Division, with all due diligence, to initiate efforts to establish RACT requirements for that source in Colorado's ozone SIP.

Current SIP review

In 2009, the Commission submitted revisions to Regulation Number 7, Section XII. to EPA related to the 1997 ozone NAAQS attainment plan. In 2011, EPA approved the attainment demonstration but disapproved portions of the Regulation Number 7 revisions. In 2013, the Commission submitted revisions to Regulation 7, Section XII. to EPA to address EPA's disapproval. During the review of the 2013 submittal, EPA noted additional concerns with the monitoring, recordkeeping, and reporting requirements for natural gas processing plants and glycol natural gas dehydrators, as well as other concerns unrelated to the attainment demonstration for the SIP revision required following the reclassification of the DMNFR area to Moderate.

Natural gas processing plants

Regulation Number 7, Section XII.G.1. identifies a leak detection and repair ("LDAR") program applicable to natural gas processing plants. This "LDAR program" includes all applicable requirements in NSPS KKK. EPA has promulgated new LDAR programs for natural gas processing plants in NSPS OOOO and NSPS OOOOa. Therefore, the Commission updated references to applicable federal NSPS (i.e., NSPS OOOO and NSPS OOOOa) monitoring, recordkeeping, and reporting requirements for natural gas processing plants in the SIP.

Glycol natural gas dehydrators

Regulation Number 7, Section XII.H. already includes a 90% control requirement for glycol natural gas dehydrators. This is a SIP requirement. During the review of the 2013 submittal, EPA noted practical enforceability concerns with the monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators. Therefore, the Commission added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in the SIP to address EPA's concerns with ensuring compliance with the control requirement. The Commission based these requirements off of the Division's glycol natural gas dehydrator Operation and Maintenance Plan template to align the Section XII.H. monitoring, recordkeeping, and reporting requirements with the Operation and Maintenance Plan template, where possible. For any glycol dehydration system monitoring, recordkeeping and reporting requirement adopted for inclusion in the SIP during this hearing that conflicts with a similar provision in a Division approved Operation and Maintenance Plan, the Commission intends that sources only have to comply with the provision adopted for inclusion in the SIP and not the competing requirement in the approved Operation and Maintenance Plan. Further, the Commission directs the Division to work with industry to revise the Division's glycol dehydration systems Operating and Maintenance Plan template to remove requirements that are duplicative of the Section XII.H. monitoring, recordkeeping, and reporting requirements, to alleviate competing requirements with Section XII.H., as necessary.

EPA requested revisions

EPA also noted concerns with other previously submitted provisions in Section XII. EPA requested minor changes to Section XII.C.1.c., and a reversion to previously approved SIP language in Sections XII.C.1.d. and XIII.E.3.a. to address concerns with discretionary language. In response, the Commission revised Section XII.C.1.c. and reverted to previously approved SIP language in Sections XII.C.1.d. and XII.E.3.a., as requested by EPA.

Incorporation by Reference in Section XIX

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Section XIX.C through H by reference.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. The Commission also adopted revisions to Regulation Number 7 to address EPA concerns that are unrelated to the reclassification to Moderate. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address combustion device auto-igniters, condensate storage tank inspections, and glycol natural gas dehydrators at oil and gas facilities and equipment leaks at natural gas processing plants. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks and glycol natural gas dehydrators. For example, Regulation Number 7 addresses more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to tri ethylene glycol ("TEG") dehydrators. The Commission revised Regulation Number 7 to include glycol natural gas dehydrator monitoring, recordkeeping, and reporting requirements to ensure compliance with the current 90% system-wide control requirement in Section XII.D. Similarly, Regulation Number 7 addresses more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. Regulation Number 7 also addresses a broader set of storage tanks than NSPS OOOO and NSPS OOOOa, which address only those storage tanks with emissions greater than 6 tpy controlled actual emissions (i.e., 120 tpy uncontrolled actual emissions) and do not require auto-igniters on combustion devices. The Commission revised Regulation Number 7 to include the auto-igniter and condensate storage tank AVO inspections in Colorado's SIP to strengthen Colorado's SIP and support Colorado's 2017 emissions inventory. In addition, Regulation Number 7 addresses more equipment leaks at natural gas processing plants than NSPS KKK, which only applies to natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. The Commission revised Regulation Number 7 to reference the more recent equipment leak detection and repair requirements in NSPS OOOO and NSPS OOOOa.

The revisions to Regulation Number 7 also address RACT requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of VOC and NOx in Colorado's ozone nonattainment area. EPA published CTGs for lithographic and letterpress printing and industrial cleaning solvents in 2006. The Commission revised Regulation Number 7 to include regulatory RACT requirements for these VOC source categories. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission revised Regulation Number 7, Sections XVI. and XIX. to include source specific regulatory RACT requirements and a combustion process adjustment for combustion equipment at major sources of NOx. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with a lower ozone NAAQS in the near future. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Section XII. strengthen Colorado's SIP, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7 Sections X. and XIII. recognize products and practices currently utilized by printing and industrial cleaning solvent operations. The revisions to Regulation Number 7 Sections XVI. and XIX. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Section XII. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7 Sections X., XIII., and XVI. similarly establish the categorical RACT requirements for similarly situated and sized sources. Where a source is not subject to a categorical RACT requirement, RACT is, by its nature, determined on a case-by-case basis.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for auto-igniters, condensate storage tank inspections, and equipment leaks at natural gas processing plants. Other revisions reflect changes in industry practice and market forces, such as the VOC content of printing materials and cleaning solvents. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate Nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

P. November 16, 2017 Revisions to Section II., XII., Section XVII., and Section XVIII.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Basis

On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate nonattainment area, Colorado must revise its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guideline ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a nonattainment area's attainment date. EPA finalized the Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado must further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado has similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions are not currently in Colorado's Ozone SIP. Therefore, the Commission is adopting RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP (Sections XII. and XVIII.). In order to make additional progress towards attainment of the NAAQS, the Commission is also adopting State Only revisions to require owners or operators of natural gas-driven pneumatic controllers in the DMNFR area to inspect and maintain pneumatic controllers.

Further, the Commission is making clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

Specific Statutory Authority

Section 25-7-105(1) of the Act directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of the Act. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program.

Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides the Commission broad authority to regulate hydrocarbons.

Purpose

As discussed above, Colorado must adopt RACT into its Ozone SIP for sources covered by the Oil and Gas CTG. While the Oil and Gas CTG recommends presumptive RACT, it does allow states the flexibility to determine what constitutes RACT for the state's covered sources. Further, while EPA's Oil and Gas CTG implementation memorandum provides guidance that the emission controls determined by the state to be RACT for the sources covered by the Oil and Gas CTG must be implemented as soon as practicable but in no case later than January 1, 2021, states also have the flexibility to determine the appropriate implementation timeframe for the sources within the state's ozone nonattainment area. The Commission determined that some of Colorado's existing regulations (*i.e.,* the "system-wide" control program for condensate tanks in Section XII.D.2.) achieve greater emission reductions than the RACT recommended by the Oil and Gas CTG. The Commission determined that some sources covered by the Oil and Gas CTG were not addressed in existing regulations (*i.e.,* pneumatic pumps).

The Commission also determined that some sources addressed in the Oil and Gas CTG (*i.e.,* components at well production facilities and natural gas compressor stations, compressors, pneumatic controllers) are already subject to existing regulations that were not yet part of Colorado's Ozone SIP. The Commission adopted many of these rules in 2014, and intends to preserve the substance of these rules, where possible, in moving them into the Ozone SIP, while making a few adjustments and improvements in response to recommendations in the Oil and Gas CTG. The Commission also adopted correlating revisions to the applicability provisions of Sections II. and XII.

The Commission relied on existing regulations in the Ozone SIP for RACT for condensate storage tank controls to satisfy Colorado's obligation to address storage vessels under the Oil and Gas CTG. The Commission adopted requirements for pneumatic pumps in Section XII. to address recommendations in the Oil and Gas CTG. The Commission revised the existing SIP requirements in Section XII.G. for equipment leaks at natural gas processing plants to address recommendations in the Oil and Gas CTG. The Commission duplicated into the Ozone SIP from Section XVII. provisions for compressors and leak detection and repair ("LDAR") for components at well production facilities and natural gas compressor stations. The Commission adjusted these LDAR requirements to address recommendations in the Oil and Gas CTG, along with updates to the recordkeeping and reporting requirements. Corresponding revisions to the LDAR program in Section XVII. are made on a State Only basis. The Commission also revised Section XVIII. to include existing State Only requirements for continuous bleed, natural gas-driven pneumatic controllers in the Ozone SIP and specify that continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants maintain a natural gas bleed rate of zero scfh.

The Commission adopted State Only provisions for the inspection and maintenance of natural gas-driven pneumatic controllers in Section XVIII.

The Commission also made clarifying revisions and corrected typographical, grammatical, and formatting errors found within the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Oil and Gas CTG, generally

The Oil and Gas CTG provides recommendations for states to consider in determining RACT for certain oil and natural gas industry emission sources. EPA included storage vessels, pneumatic controllers, pneumatic pumps, compressors, equipment leaks, and fugitive emissions in the Oil and Gas CTG because EPA determined that these sources are significant sources of VOC emissions. EPA defines RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” States may implement approaches that differ from the recommendations in the Oil and Gas CTG so long as they are consistent with the CAA, EPA’s implementing regulations, and policies on interpreting RACT.

Applicability to hydrocarbons (Section II.B.)

Section II.B. currently exempts negligibly reactive volatile organic compounds, such as methane and ethane, from requirements of the SIP, while making hydrocarbon emissions, including methane and ethane, subject to State Only regulation under Sections XVII. and XVIII. Section XVII. sets a threshold for leaks requiring repair that is based on the concentration of hydrocarbons, as determined using EPA Method 21. Section XII.L. applies the same EPA Method 21 hydrocarbon threshold for leaks requiring repair. The Commission revised Section II.B. to clarify that the Section XII.L. hydrocarbon threshold and Section XVIII. natural gas emission standards serve only as VOC indicators and the SIP does not regulate hydrocarbon emissions.

The continuous bleed, natural gas-driven pneumatic controller requirements in Section XVIII. reduce natural gas emissions, which consists of other pollutants in addition to VOCs. Despite the presence of other constituents, natural gas is principally methane and the Commission intends to regulate emissions of natural gas as hydrocarbons, including methane and ethane, on a State Only basis as described in Sections II.B. and XVIII. The Oil and Gas CTG also utilizes a natural gas bleed rate standard for continuous bleed pneumatic controllers and the Oil and Gas CTG LDAR program employs a methane-based threshold for EPA Method 21 leak detection. Therefore, these revisions are consistent with the Oil and Gas CTG and the CAA.

While the revisions to Sections XII. and XVIII. to include provisions in Colorado’s Ozone SIP are limited to the DMNFR, the Commission acknowledges the importance of reducing hydrocarbon emissions from the oil and gas sector (*i.e.*, upstream, midstream, and transmission) statewide. Therefore, without prescribing any particular outcome, the Commission directs the Division to initiate and lead a stakeholder process over the 2018-2019 timeframe to evaluate potential areas for cost-effective hydrocarbon emission reductions. Stakeholders will nominate topics for evaluation, which may include, but are not limited to, the frequency of LDAR inspections, transmission segment compressor emissions, natural gas-driven and zero emission pneumatic controllers outside the DMNFR (to be informed by the pneumatic study and inspection program), and potential expansion of the requirements adopted in the DMNFR as part of this rulemaking. The Division will brief the Commission on the stakeholder process in January 2019 and present recommendations for any new proposals for emission reductions by no later than January 2020. The Commission intends that one representative of industry, local government, and the environmental community each will have the opportunity to speak during the briefings.

Applicability of Section XII. (Section XII.A.)

The Commission is clarifying the applicability of Section XII. Historically, Section XII. has applied to operations that involve the collection, storage, or handling of condensate in the DMNFR. While this remains the case, the requirements in Section XII.J. for compressors, Section XII.K. for pneumatic pumps, and Section XII.L. for components at well production facilities and natural gas compressor stations also apply to those facilities and equipment collecting, storing, or handling other hydrocarbon liquids.

Section XII.A.5. further provides that subject well production facilities are those with uncontrolled actual VOC emissions greater than or equal to one ton per year ("tpy"). This applicability threshold addresses the Oil and Gas CTG's recommended barrels of oil equivalent ("BOE") exemption. EPA crafted the BOE exemption believing that well production facilities with an average production less than 15 BOE per well per day were inherently low emitting facilities. EPA later determined that information submitted on the draft CTG and proposed NSPS OOOOa did not support this conclusion. Therefore, in addition to the complications concerning tracking BOE, the Commission chose to rely upon an uncontrolled actual VOC tpy threshold for well production facility applicability. The use of a tpy threshold is also consistent with Colorado's current air pollutant reporting and permitting thresholds.

Further, Section XII.A. historically exempted from the requirements of Section XII. those operations reflecting a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the DMNFR area. That exemption continues to apply to Sections XII.B. through XII.I., but is not extended to Sections XII.J., XII.K., and XII.L.

Definitions (Sections XII.B. and XVII.A.)

The Commission is adopting definitions into Section XII.B., most of which are consistent with the existing definitions of Section XVII.

In the definition of "component", the Commission is clarifying both in Section XII.B. and in Section XVII.A., that thief hatches and other openings on storage tanks are included in the definition as a pressure relief device. This revision clarifies that leaks can occur from the thief hatch (*e.g.*, faulty or dirty seals) that are different than vented emissions under the standard in Section XVII.C.2.a., and that such leaks are subject to the LDAR program. The Commission anticipates that emissions from storage tanks identified as leaks requiring repair through the LDAR inspections under Sections XII.L. or XVIII.F. will be recorded and reported as leaks starting in 2018 for the 2019 annual report.

The Commission is adding a definition of "custody transfer" that applies to custody transfers of both natural gas and oil products. The Commission is also adding definitions for "natural gas driven diaphragm pump" and "natural gas processing plant" that correspond to federal definitions.

Operate without venting clarification (Section XVII.C.2.a.)

The Commission is providing additional detail concerning provisions adopted in 2014 that established an "operate without venting" standard for storage tanks. In response to industry concern that Section XVII. does not sufficiently define "venting" or delineate "venting" from "leaking," the Commission is adopting provisions clarifying which emissions from storage tanks are considered "venting". Section XVII.F. defines "leaking" in terms of infra-red camera or EPA Method 21 inspections of components. While storage tanks may also have leaks, as the Commission recognizes by including thief hatches or other openings on storage tanks in the definition of component, the Commission now further clarifies the "venting" standard by specifying that "venting" is emissions that are primarily the result of over-pressurization or that are from an open or visibly unseated pressure relief device (*e.g.*, thief hatch). The Commission intends that "visibly unseated" means visible from the outside of the pressure relief device and does not require an owner or operator to open a pressure relief device to determine if the seal is proper. The Commission also authorizes the Division to request a demonstration from the owner or operator that "venting" emissions observed by the Division were not primarily the result of over-pressurization. The Commission intends that such demonstration request allow an owner or operator to provide case specific information or other sufficient details that the design, operation, and maintenance of the facility is adequate to prevent over-pressurization. In clarifying a difference between "leaking" and "venting," the Commission does not prohibit component leaks, per se, so long as leaks are repaired under the applicable repair time frames but does continue to prohibit "venting" from storage tanks.

Ozone season clarification (Sections XII.F.4. and XII.H.6.)

In October 2015, the EPA finalized a revision to the ozone NAAQS. (80 Fed. Reg. 65292 (Oct. 26, 2015)). In publishing its final rule, the EPA revised the length of Colorado's ozone season. Colorado's ozone season is now year-round, rather than the months of May through September. The Commission therefore revised references to "ozone season" in Sections XII.F.4. and XII.H.6. to reflect that the requirements now apply during the months of May to September. There are no substantive changes to the underlying requirements resulting from this revision.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Commission is updating the LDAR program applicable to equipment leaks at natural gas processing plants in the DMNFR by requiring owners or operators to comply with 40 C.F.R. Part 60 (NSPS), Subparts OOOO or OOOOa instead of complying with NSPS Subpart KKK, which is an earlier NSPS and less stringent. Subpart KKK requires sources to implement a NSPS Subpart VV level LDAR program, while Subpart OOOO requires sources to implement a NSPS Subpart VVa level LDAR program. A Subpart VVa level LDAR program is recommended for equipment at natural gas processing plants in the Oil and Gas CTG. The Commission determined that a 2019 implementation date would provide owners and operators of existing natural gas processing plants a reasonable period of time to establish and obtain the necessary resources to transition from Subpart KKK to Subpart OOOO LDAR requirements.

Compressors (Section XII.J.)

The Commission is adopting the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. into new Section XII.J. in order to include the requirements in Colorado's Ozone SIP. The Commission is expanding the existing reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to address recommendations in the Oil and Gas CTG. Owners or operators of existing reciprocating compressors at natural gas processing plants must begin monitoring the reciprocating compressor hours of operation on January 1, 2018, starting at zero, in relation to the rod packing replacement requirement, conduct the first rod packing replacement prior to January 1, 2021, or route emissions to a process beginning May 1, 2018.

The Commission intends to allow owners or operators the option to reduce VOC emissions by routing centrifugal compressor emissions to a process or control and reciprocating compressor emissions to a process, consistent with the recommendations in the Oil and Gas CTG. With respect to centrifugal compressors, the Oil and Gas CTG and related federal requirements reveal that "process" generally refers to routing emissions via a closed vent system to any enclosed portion of a process unit (*e.g.*, compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Similarly, with respect to reciprocating compressors, routing to a process includes using a rod packing emissions collection system that operates under negative pressure and meets cover and closed vent system requirements. The negative pressure requirement ensures that all emissions are conveyed to the process and avoids inducing back pressure on the rod packing and resultant safety concerns. The Commission recognizes that there may a distinction between air pollution control equipment and process equipment (see e.g., U.S. EPA Letter to Timothy J. Mohin RE: Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment (Nov. 27, 1995)). For example, as noted in the Oil and Gas CTG, vapor recovery units and flow lines that "route emissions to a process" may be considered part of the process and not a control device, however, a related cover and closed vent system, if present, are still subject to applicable requirements. Further, components (as defined in these rules) located within a process or that are part of process equipment are subject to the Section XII.L. LDAR requirements. The Commission intends that owners or operators will follow similar procedures when complying with centrifugal and reciprocating compressor requirements in Section XII.J.

The Commission has adopted an inspection program for compressors, but also intends to provide owners or operators with the alternative of complying with other requirements, including the LDAR program adopted into Section XII.L. While the requirements of the LDAR program would replace the annual visual inspections and EPA Method 21 inspections of the cover and closed vent systems for defects and leaks, owners or operators would still need to conduct monthly inspections of their combustion devices. Compliance with the LDAR program is not limited to the inspection frequency and methods specified therein; owners or operators will also need to maintain records of the inspections and submit reports to the Division, consistent with the requirements of the LDAR program.

The Commission has specified an inspection and repair schedule for compressors, but has recognized that there may be reasons that a system is unsafe or difficult to inspect, or where a repair may not be feasible. Owners or operators will need to maintain records of each cover or closed vent system that is unsafe or difficult to inspect and schedule for inspection when circumstances allow. Similarly, when a repair is infeasible, insofar as it would require a shutdown of the equipment, repair can be delayed until the next scheduled shutdown but must be completed within two years after discovery. The Commission expects owners or operators to attempt to confirm repair before starting up operation after shutdown, to the extent practicable. The Commission also expects that if the repair attempt can be made during an unplanned shutdown, it will be.

The Commission adopts the monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

As an alternative to complying with the control, monitoring, and recordkeeping requirements in Section XII.J., owners or operators may instead comply with centrifugal or reciprocating compressor control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

<u>Natural gas driven diaphragm pumps (Section XII.K.)</u>

The Oil and Gas CTG contains recommendations for RACT for natural gas-driven diaphragm pumps. The Commission has not previously adopted regulations specifically directed at this type of equipment, and does so in Section XII.K.

The Oil and Gas CTG recommends that the pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG also recommends that owners or operators of pumps located at well sites route VOC emissions from the pneumatic pump to an onsite control device or process, unless the pneumatic pump operates on fewer than 90 days or an engineering assessment shows that routing the pneumatic pump emissions to a control device or process is technically infeasible. The assessment of technical feasibility may include safety considerations, distance from the control device, pressure losses and differentials in the closed vent system, gas pressure, and the capacity of the control device, among other things. The Commission acknowledges that RACT, by EPA definition, includes both technological and economic feasibility elements. The Commission determined that the cost of routing pneumatic pump emissions to an existing control device or process is reasonable and is, therefore, only providing an exemption from the emission control requirement based on technical infeasibility. However, the Commission does not intend to limit future RACT determinations due to limiting the pneumatic pump infeasibility analysis to technical ability. In addition, the 90-day exemption for pumps was included to address intermittently used or portable pumps. Consistent with the Oil and Gas CTG, the Commission intends that if a pump operates on any period of a calendar day, that day would be included in the calculation for applicability of the 90-day exemption.

The Commission does not expect an owner or operator to install new equipment specifically to route pneumatic pump emissions to a control or process but intends that when an owner or operator subsequently otherwise installs a control device or it becomes technically feasible to route pump emissions to a process, then the owner or operator will capture the emissions from the pneumatic pump and route the emissions to the newly installed control device or feasible process. Routing to a control or process generally refers to routing the emissions through a closed vent system to a vapor recovery unit, combustion device, or enclosed portion of a process where emissions are recycled and/or consumed.

The Commission has applied the same flexibility for pneumatic pumps as it has for compressors; owners or operators may comply with the inspection requirements in Section XII.K. or may follow the LDAR program in Section XII.L. Also similar to compressors, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak or equipment requiring repair so long as repair is completed within two years after discovery. As with compressors, the Commission expects owners or operators to attempt to confirm repair before starting up operation after a shutdown and make an attempt to repair during unscheduled shutdowns, to the extent practicable.

As an alternative to complying with the control, monitoring, recordkeeping, and reporting requirements in Section XII.K., owners or operators may instead comply with pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

<u>Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)</u>

The Oil and Gas CTG recommends LDAR programs at well sites *(i.e.*, well production facilities) and gathering and boosting stations (*i.e.*, natural gas compressor stations), including inspection frequencies, recordkeeping, and reporting. The Commission established Colorado's well production facility and natural gas compressor station LDAR program in 2014 in Section XVII.F., which is not part of the Ozone SIP. In creating a LDAR program in the Ozone SIP, the Commission intends to maintain as much of the current program as feasible. Where the Commission adopted revisions in Section XII.L. that differ from language currently found in the State Only LDAR program, the Commission in most cases made the same or similar revisions to the corresponding provisions in Section XVII.F.

Inspection, repair, and remonitoring

The Oil and Gas CTG recommends LDAR inspections at a minimum quarterly frequency for gathering and boosting stations and a minimum semi-annual frequency for well sites. The Commission is adopting inspection frequencies to address those recommendations in Section XII.L. The Commission is not modifying the LDAR schedules in Section XVII.F. The Commission intends that for those sources required by Section XVII.F. to conduct more frequent LDAR monitoring than specified in Section XII.L., the owner or operator may comply with Sections XII L.1. and XII.L.2. by complying with Sections XVII.F.3. and XVII.F.4. As with the LDAR inspection frequency in Section XVII.F., the Commission expects that owners or operators will ensure that inspections are appropriately spaced on the frequency schedules (*e.g.,* quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Oil and Gas CTG does not recommend a semi-annual LDAR inspection frequency at well sites with a gas to oil ratio less than 300 and which produce, on average, less than or equal to 15 BOE per well per day. The Commission recognizes that a component of RACT is balancing the emission reductions with the cost of the controls, and agrees that there should be a floor below which the recommended minimum frequency does not apply. The Commission determined a threshold of one tpy VOC emissions addresses this balance and the recommendation in the Oil and Gas CTG. Adopting an emissions based threshold maintains consistency with the current Regulation Number 7 applicability program and promotes the clarity and effectiveness of the regulation.

The Commission determined that annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy and semi-annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than six tpy address the Oil and Gas CTG's recommendations.

The Commission understands that the revised inspection frequencies will result in a significant number of new inspections. However, annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy will be less burdensome than semi-annual inspections. The Commission has determined that the emission reductions achieved by this program will improve the ability of the DMNFR area to attain the ozone standard and are cost-effective. While the rule specifies that the new inspection frequencies begin to apply as of June 30, 2018, the rule does not require that the first periodic inspection be completed by June 30, 2018. The Commission also does not require that monitoring be conducted in advance of this date; however, inspections done after January 1, 2018, that are in addition to current required LDAR monitoring frequencies may count towards the first annual or semi-annual inspection, or inspections done in the previous quarter at natural gas compressor stations. The Commission encourages owners or operators to conduct inspections prior to the 2018 summer ozone months to more effectively take advantage of the resulting emission reductions.

To ensure that the Ozone SIP LDAR program in Section XII.L. works with the existing State Only LDAR program in Section XVII.F., the Commission has maintained the same thresholds for identifying leaks that require repair. While the Oil and Gas CTG employs a methane concentration threshold when detected with EPA Method 21, Colorado's LDAR program uses a hydrocarbon concentration threshold. The Commission has also revised Section II. to clarify that Section XII.L. includes the use of hydrocarbons as an indicator of VOC emission reductions.

Concerning the use of non-quantitative instrument monitoring methods, the Commission adopted a quality assurance requirement that owners or operators maintain and operate such devices according to manufacturer recommendations. This requirement corresponds to recommendations in the Oil and Gas CTG concerning the maintenance and operation of OGI uses to detect fugitive emission components. The Commission intends for the Division to work with owners or operator to address any concerns that arise from manufacturer specifications for the maintenance of non-quantitative instrument monitoring methods.

Consistent with the current LDAR program in Section XVII.F., the Commission adopted a requirement to make a first attempt to repair an identified leak within five working (*i.e.,* business) days of discovery. In both Section XII.L. and in Section XVII.F., the Commission has included a requirement that repairs be completed within 30 days unless one of the existing justifications for delay of repair applies. As with compressors and pneumatic pumps, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak requiring repair so long as repair is completed within two years of discovery. The Commission has also maintained the flexibility of the State Only LDAR program in the SIP by giving owners or operators detecting leaks with a non-quantitative method (*e.g.,* IR camera) the ability to quantify the leaks within five working days. If the quantification shows that the leak must be repaired under Section XII.L.5., the deadline to repair runs from the date of discovery, not from the date of quantification.

As it did for Section XVII.F.7.c. in 2014, the Commission has also memorialized its intent, in Section XII.L.5.c., that operators not be subject to enforcement for leaks so long as operators are complying with the LDAR program requirements. However, as it also explained in 2014, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Section XII.C. For example, closing an open thief hatch within five days of an LDAR inspection does not shield an owner or operator from a possible violation of the requirement to minimize emissions to the maximum extent practicable.

Similarly, the Commission does not intend to relieve owners or operators of the obligation, on a State Only basis, to comply with the requirements of Section XVII., including the requirements in Sections XVII.B. and XVII.C.2. to minimize leakage to the extent reasonably practicable and operate without venting, respectively. However, the Commission does not intend these State Only provisions be enforceable under the Ozone SIP.

Recordkeeping and reporting

The Commission has determined that the current requirements did not adequately incentivize owners or operators to make all reasonable good faith efforts to obtain parts necessary to complete repairs. As a result, some leaks continued on delay of repair lists for an unreasonable length of time. Therefore, the Commission has determined that a review and record of such delays by a representative of the owner or operator is necessary for those occasions where unavailable parts have resulted in a delay of repair beyond 30 days.

The Commission expanded the recordkeeping for repair dates to include records of the type of repair method applied. The Commission determined this recordkeeping element aligns with recommendations in the Oil and Gas CTG and will more accurately inform repair activities. The Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of repair to ensure that owners and operators are consistently recording the information required.

The Commission also expanded the requirements for the annual LDAR report to ensure that the data submitted to the Division more accurately represents and summarizes the activities and effectiveness of the LDAR program. The Commission intends that the LDAR reports include the number of inspections, leaks requiring repair, leaking component type, and monitoring method by which the leaks were found – broken out by facility type (*i.e.,* inspection frequency tier of well production facility or natural gas compressor station).

The Commission intends that both the SIP and State Only LDAR reporting requirement can be satisfied by one report. The Commission expects that the first annual report containing the information required by these revisions will be submitted by May 31, 2019 (*i.e.,* no changes are expected to current requirements for the May 31, 2018, annual report representing leak detection and repair activities conducted during 2017).

Alternative approved instrument monitoring method ("AIMM")

The Commission has adopted a process for the review and approval of alternative instrument monitoring methods. The CAA prohibits a state from modifying SIP requirements except through specified CAA processes. EPA interprets this CAA provision to allow EPA approval of SIP provisions that include state authority to approve alternative requirements when the SIP provisions are sufficiently specific, provide for sufficient public process, and are adequately bounded such that EPA can determine, when approving the SIP provision, how the provision will actually be applied and whether there are adverse impacts. (State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction, 80 Fed. Reg. 33917-33918, 33927 (June 12, 2015)) Therefore, the Commission includes an application and review process in the SIP for the potential approval of instrument monitoring methods as alternatives to an infra-red camera or EPA's Method 21. The approval may also include modified recordkeeping and reporting requirements based on the capabilities of the potential alternative instrument monitoring method. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative AIMM must be capable of reducing emissions through the detection and repair of leaks comparable to the leaks detected and repaired as specified in the SIP to be potentially approvable.

The Commission received comments from stakeholders requesting that the Commission explicitly provide for the ability to employ certain alternatives not equipped with the leak detection capabilities of infra-red cameras or Method 21. These stakeholders emphasized that monitoring technologies are evolving rapidly and new technologies and monitoring programs are being developed that, when used on their own or in conjunction with other methods, may provide the same or better leak detection and repair results, at potentially lower costs. The process outlined in Section XII.L.8. requires an applicant to demonstrate that the proposed alternative monitoring achieves emission reductions that are at least as effective as the leak detection and repair program in Section XII.L. The Commission intends that the rule be flexible enough to allow the Division to consider such alternative monitoring methods or programs, as long as the applicant can demonstrate that the proposed method or program achieves emission reductions that are as effective as other approved technologies or methods. To make this demonstration, an applicant may consider demonstrating that a program of alternative inspection frequencies, pollutants detected, or leak thresholds for repair achieves emission reductions comparable to the inspection frequencies and leaks requiring repair thresholds in Section XII.L., thus the consideration of an alternative leak detection program. The Commission recognizes that current, established approaches or methodologies to evaluate the performance of alternative monitoring technologies and programs as compared to baseline monitoring technologies (infra-red camera, EPA Method 21) do not yet exist. However, such methodologies are being developed.

For example, the Interstate Technology and Regulatory Council (ITRC), in which Colorado participates, is developing, but has not yet published, a guidance document to establish, if possible, a consensus for evaluating and comparing the effectiveness of leak detection technologies. While the criteria for evaluating the effectiveness of an alternative program as compared to the base program is being developed, alternative monitoring method applicants may submit an application for approval of an alternative monitoring method but must be prepared to present a robust and complete evaluation of the technology or program’s performance that allows for comparison to the base technologies in the SIP. It is possible the Division may delay consideration and final determination regarding an alternative monitoring method or program application until established comparison criteria are developed or submitted. Taking into account the deliberations of the ITRC process, the Commission expects that the Division will consider complete applications in a timely manner.

The Commission also received comments from stakeholders requesting that the Commission clarify EPA’s participation regarding potential alternative monitoring methods. As discussed above, the Commission believes that the process to review and potentially approve alternative monitoring methods is sufficiently constrained such that EPA, when approving the process, can be assured as to what emission reductions any such alternative monitoring will achieve in the context of the Section XII.L. LDAR program. However, the Commission also recognizes EPA’s technical knowledge and is requiring the Division to continue to engage with EPA concerning alternative monitoring methods. Specifically, the Division must provide complete applications to EPA early in the review process, which has previously ranged from three to nine months. The Division must also provide EPA six (6) months after approval of an alternative for further EPA review. The Commission believes this process provides sufficient time for meaningful engagement with EPA.

Clarifications

The Commission is clarifying, both in Section XII.L. and Section XVII.F., that all detected emissions are leaks, but that only those leaks above specified thresholds require repair. The Commission did not intend that leaks falling below the specified thresholds would not be considered “leaks,” only that those leaks did not require repair in accordance with the prescribed schedules. The Commission has further clarified that only records of leaks requiring repair need to be maintained.

Regulation Number 7 already requires that owners or operators remonitor repaired leaks with an AIMM. AIMM includes EPA Method 21, which includes the soapy water method, and the Commission further clarifies that an owner or operator may use the soapy water method in EPA Method 21 to remonitor a repaired leak.

Some stakeholders asked the Commission to “clarify” that the LDAR repair, remonitoring, recordkeeping, and reporting requirements applied only to those leaks discovered by the owner or operator, and not those discovered by the Division. The Commission believes that would not be a clarification, but a change to the current program, and does not make that requested revision at this time. Therefore, the repair, remonitoring, recordkeeping, and reporting requirements continue to apply to leaks discovered by the Division.

Pneumatic controllers (Section XVIII.)

The Commission is adopting both Ozone SIP and State Only revisions to Section XVIII.

The Commission added definitions of continuous bleed and intermittent pneumatic controller. The Commission also added “continuous bleed” to several provisions throughout Sections XVIII.C. through XVIII.E. to clarify that the provisions adopted in 2014 primarily applied to continuous bleed pneumatic controllers (which emit continuously) as opposed to intermittent pneumatic controllers (which emit only when actuating).

Pneumatic controllers at or upstream of natural gas processing plants

Section XVIII. already requires that owners or operators install low-bleed pneumatic controllers at or upstream of natural gas processing plants, unless a high-bleed pneumatic controller is required for safety or process purposes. This requirement is consistent with the Oil and Gas CTG and the Commission intends that these provisions be included in Colorado’s Ozone SIP.

The Commission adopts additional requirements, consistent with the Oil and Gas CTG, related to pneumatic controllers at natural gas processing plants. The Commission is requiring that all continuous bleed, natural gas-driven pneumatic controllers at a natural gas processing plant have a bleed rate of zero (*i.e.,* no VOC emissions), unless a pneumatic controller with a bleed rate greater than zero is necessary due to safety and process reasons. To satisfy this requirement, owners or operators of natural gas processing plants could, for example, drive pneumatic controllers with instrument air, use mechanical or electrically powered pneumatic controllers, or use self-contained pneumatic controllers that release natural gas to a downstream pipeline instead of to the atmosphere. The requirements to submit a justification for a pneumatic controller exceeding the emission standard to the Division, as well as the requirements for tagging and records, duplicate and are intended to be consistent with existing requirements related to high-bleed pneumatic controllers. The requirement to maintain pneumatic controllers exceeding the applicable emission standard are also duplicated from the existing high-bleed maintenance requirement, but revised to include the suggested maintenance actions specifically in the applicable provisions, instead of referring to an “enhanced maintenance” definition. The Commission revised the maintenance requirement in this manner to separate the actions taken to maintain a pneumatic controller exceeding the applicable emission standard from the, potentially very similar, actions taken to return a pneumatic controller to proper operation. For example, the owner or operator of a high-bleed pneumatic controller or a pneumatic controller with a bleed rate greater than zero at a natural gas processing plant is required to perform specified maintenance on the pneumatic controller regardless of whether or not the pneumatic controller is determined to be properly operating. In contrast, the owner or operator of a pneumatic controller inspected under Section XVIII.F. must conduct enhanced response to return that pneumatic controller to proper operation.

Additionally, the Commission is requiring owners or operators to maintain records demonstrating their continuous bleed, natural gas-driven pneumatic controllers meet the applicable low-bleed or bleed rate of zero standards. These records are also intended to inform the extent to which continuous bleed pneumatic controllers are used in the DMNFR. The Commission understands that the number of continuous bleed, natural gas-driven pneumatic controllers in use by an operator can change frequently, and is not requiring a running log or count of each individual pneumatic controller.

The Commission adopted these recordkeeping requirements with the expectation that owners or operators can keep records including, but not limited to, site-specific documentation of continuous bleed, natural gas-driven pneumatic controllers such as manufacturer specifications, engineering calculations, field test data, or documentation of a company's continuous bleed, natural gas-driven pneumatic controller purchase and installation program ensuring that any such pneumatic controller meets the applicable bleed rate standard.

Clarification

The Commission is also clarifying the intent behind provisions adopted in 2014 regarding the use of pneumatic controllers powered by instrument air (as opposed to natural gas) when grid power is being used. In 2014, the Commission intended that when a pneumatic controller was proposed for installation, owners or operators would power the pneumatic controller via electrical power instead of natural gas when electrical grid power was being used on-site. The provisions adopted in 2014 allowed owners or operators to install a pneumatic controller with VOC emissions equal to or less than a low-bleed pneumatic controller in some situations. The Commission has learned that some owners or operators interpret the rule as providing the option of installing either no-bleed or low-bleed pneumatic controllers in all situations.

Even though the Commission believes its intent was clear, the Commission recognizes that the rule could fairly be described as ambiguous and that there is a good faith legal argument for the alternative interpretation. The Commission is revising the rule to clarify that where electric grid power is being used on site and it is technically and economically feasible to install no-bleed pneumatic controllers, any newly installed pneumatic controllers must be no-bleed. Where the owner or operator determines it is not technically and economically feasible to install a no-bleed pneumatic controller, the owner or operator may install a low-bleed or intermittent pneumatic controller.

The Commission recognizes that the installation of an electrically-powered controller may have been feasible in 2014, but may not be feasible to retrofit at this time. The Commission nonetheless encourages owners or operators statewide who, based on a misreading of the regulation, did not install a no-bleed pneumatic controller to evaluate whether retrofitting controllers – with no-bleed or self-contained pneumatic controllers – at this time is technically and economically feasible. The Commission also encourages owners and operators statewide to install, or retrofit with, no-bleed or self-contained pneumatic controllers at locations across the state, even where on site electrical grid power is not available to the extent there is no significant air quality disbenefit in doing so.

Natural gas driven pneumatic controller inspection and enhanced response (State Only)

Following the 2014 rulemaking, the Commission requested that the Division continue its investigation into potential regulations for intermittent pneumatic controllers. During the recent 2016 ozone rulemaking, stakeholders again asked the Commission to address intermittent pneumatic controllers. In response, the Commission again directed the Division to evaluate potential emission reduction measures for intermittent pneumatic controllers.

The Commission is adopting an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven pneumatic controllers. While the Oil and Gas CTG notes the value of pneumatic controller inspection and maintenance, the Oil and Gas CTG does not specify a pneumatic controller inspection and maintenance as presumptive RACT. Therefore, while the Commission determined that these revisions are technically and economically feasible, the revisions are proposed as State Only in the DMNFR and are not made part of the Ozone SIP at this time. Natural gas-driven pneumatic controllers include continuous bleed, intermittent, and self-contained pneumatic controllers. Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere.

The Oil and Gas CTG suggests that maintenance of pneumatic controllers, including cleaning and tuning, can eliminate excess emissions from the devices. While the Oil and Gas CTG's recommended RACT (low-bleed or zero emissions) applies to continuous bleed, natural gas-driven pneumatic controllers, the discussion concerning enhanced maintenance of pneumatic controllers builds on earlier EPA discussions, such as EPA's 2014 Pneumatic Controller White Paper, and is not limited to continuous bleed pneumatic controllers. The Commission recognizes that continuous bleed and intermittent pneumatic controllers are designed to have emissions, however these pneumatic controllers can also have excess emissions when not operating properly. As a result, the Commission believes that a pneumatic controller inspection and response program will reduce the excess emissions from such pneumatic controllers.

The Commission intends to apply the same find and fix approach used in the LDAR requirements in Sections XII.L. and XVII.F. to all natural gas-driven pneumatic controllers in the DMNFR. The Commission is requiring that natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the pneumatic controller is operating properly, in contrast to quantitatively comparing pneumatic controller emissions to a regulatory threshold. The Commission is requiring that owners or operators inspect pneumatic controllers at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

The Commission expects that owners or operators will inspect their pneumatic controllers during the same LDAR inspections, and using the same AIMM, conducted for compliance with Sections XII.L. or XVII.F. The pneumatic controller inspection and enhanced response process is intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven pneumatic controller using AIMM to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those pneumatic controllers with detected emissions. Second, the owner or operator must determine whether the pneumatic controllers with detected emissions are operating properly. Use of an AIMM is not required during this second step; the Commission does not at this time intend to mandate to owners or operators how to determine if their pneumatic controllers are operating properly. During this second step, if an owner or operator determines that the pneumatic controller is operating properly, no further action is necessary. Third, where an owner or operator determines the pneumatic controller is not operating properly, the owner or operator must take actions to return an improperly operating pneumatic controller to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those pneumatic controllers that the owner or operator determined not to be operating properly.

Similar to the LDAR records, owners or operators must keep records of the date the pneumatic controller was returned to proper operation and a description of the types of actions taken. As with well production facility and natural gas compressor station LDAR records, the Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of response actions to ensure that owners and operators are consistently recording the information required. The Commission expects that owners or operators will include the pneumatic controller information as State Only information in their LDAR annual reports. In returning a pneumatic controller to proper operation, the Commission relies upon the previously defined term, now enhanced response, found in Section XVIII.B. related to maintaining high-bleed pneumatic controllers. The Commission has expanded this definition to guide responsive activities concerning all natural gas-driven pneumatic controllers. Recognizing that the function and potential maintenance or repair of pneumatic controllers can be variable, owners or operators are not restricted to using an AIMM to determine proper operation or verify the return to proper operation.

The Commission has adopted a "reassessment" provision for this inspection and enhanced response program following a Division led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The Commission also recognizes that owners and operators may currently have limited information on "good engineering and maintenance practices" for pneumatic controllers and intends that more information on these practices will be gathered during the pneumatic study and implementation of Section XVIII.F. to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry's proposal, a task force will be convened by January 30, 2018, consisting of representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection will begin no later than by May 1, 2018. The task force will brief the Commission annually and make any recommendations on its findings in a report to the Commission, due May 1, 2020. The Commission intends that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the Commission. The Commission intends that this information be used to reassess the natural gas-driven pneumatic controller requirements of Section XVIII.F. Section XVIII.F. will remain in effect until rescinded, superseded, or revised.

The Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers, which highlights the need for the reassessment of Section XVIII.F. as well as enforcement discretion. The Commission intends that while the task force is actively working on data collection and the 2020 report to the Commission, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator. Any information gathered through the task force, including on preventative, good engineering, and maintenance practices, will be used to reassess Section XVIII.F. and will not be used for enforcement purpose through 2020.

Additional Considerations

Colorado must revise Colorado's Ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. The Commission carefully considered what provisions to include in Colorado's Ozone SIP, especially given Colorado's pre-existing emission control requirements that address most of the same sources addressed by the Oil and Gas CTG, yet do so differently. Some of these pre-existing requirements were adopted into Colorado's SIP and some will remain as State Only requirements. In determining what existing provisions would be included in Colorado's Ozone SIP, the Commission considered: 1) whether or not Colorado had existing emission control measures for the same sources covered by the Oil and Gas CTG; 2) whether these existing requirements were already adopted for inclusion in the Ozone SIP; and 3) the degree of emissions reductions achieved by any existing Colorado emission control measures in comparison to the Oil and Gas CTG. In resolving differences between existing Colorado provisions and the Oil and Gas CTG, preference was given to existing Colorado provisions, especially those already incorporated into Colorado's Ozone SIP and Colorado's existing regulatory framework. For example, the Commission relied upon existing storage tank requirements already adopted into Colorado's Ozone SIP. In the case of well production facility LDAR, the Commission adopted a tpy applicability threshold in place of the Oil and Gas CTG's BOE threshold, which applies to more sources than the Oil and Gas CTG, yet adopted a less frequent inspection frequency into the Ozone SIP for the smaller facilities than the Oil and Gas CTG.

In determining whether or not any additional requirements would be relied upon in establishing RACT in Colorado's Ozone SIP for the oil and gas sector, the Commission determined whether or not the emission control measures were necessary for the ozone attainment demonstration. In the case of LDAR for pneumatic controllers at well production facilities and natural gas compressor stations, the Commission adopted emission control measures as State Only measures given the need to obtain emission reductions as well as more information on this source type. These examples illustrate the Commission's careful consideration of what provisions to include in Colorado's Ozone SIP.

The CAA requires that Colorado's Ozone SIP include RACT for all sources covered by a CTG, such as the emission sources addressed in the Oil and Gas CTG. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs.

The Commission is also revising certain State Only regulations to reduce emissions and promote attainment of current federal ozone standards. Specifically, the Commission is adopting requirements related to the inspection of natural gas-driven pneumatic controllers at oil and gas facilities. As discussed above, malfunctioning pneumatic controllers can result in significant hydrocarbon emissions. The DMNFR ozone nonattainment area is currently classified as a Moderate nonattainment area under the 2008 ozone NAAQS. The deadline for the DMNFR to attain the 2008 ozone NAAQS is July 2, 2018. If the DMNFR does not attain the standard or does not receive an extension, EPA may reclassify the DMNFR as a Serious nonattainment area under the 2008 ozone NAAQS. In addition, the Commission approved a designation recommendation for the DMNFR under the 2015 ozone NAAQS in September 2016.

While EPA has not yet acted on this recommendation, the Commission expects the DMNFR will be designated as nonattainment under the 2015 ozone NAAQS and is taking action to promote attainment of the more stringent standard. Given both the potential for a reclassification to Serious under the 2008 ozone NAAQS and the need to reduce ozone to meet the more stringent 2015 ozone NAAQS, the Commission is adopting the State Only pneumatic controller inspection requirements that further reduce ozone precursors emissions, notwithstanding the fact that a pneumatic controller inspection program is not specified as presumptive RACT in the Oil and Gas CTG.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission. The EPA revised the ozone NAAQS in 2015 and the DMNFR must attain the new standard or face additional requirements. The revisions to Regulation Number 7 address RACT for compressors, pneumatic pumps, pneumatic controllers, natural gas processing plants, natural gas compressor stations, and well production facilities. The revisions apply to equipment already regulated by Colorado on a State Only basis and apply to equipment not previously subject to regulation. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to the regulated equipment. The Commission determined that the adopted RACT SIP requirements are comparable to the Oil and Gas CTG's recommendations. The Commission also determined that there are not comparable federal rules requiring the inspection and maintenance of natural gas-driven pneumatic controllers.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa to allow an owner or operator to request EPA approve compliance with an alternate emission limitation (e.g., alternative monitoring, state program) instead of related requirements in NSPS OOOOa.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here. Further, the State Only pneumatic controller inspection requirements address the lack of federal requirements concerning emissions from malfunctioning pneumatic controllers.

(IV) Unless federal law changes, Colorado will be required to comply with the more stringent 2015 ozone NAAQS in the near future and may be required to comply with the more stringent requirements for a Serious nonattainment area. These current SIP and State Only revisions may improve the ability of the regulated community to comply with new, more stringent, future requirements. In addition, these revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommended oil and gas RACT provisions.

(V) EPA has established October 27, 2018, deadline for this SIP submission. EPA has not yet established deadlines for the DMNFR to attain the 2015 ozone NAAQS. However, given the potential reclassification of the DMNFR to Serious under the 2008 ozone NAAQS, the Commission determined that taking action to reduce ozone precursor emissions as soon as practicable, either as part of the SIP or on a State Only basis, is warranted.

(VI) The revisions to Regulation Number 7 Sections XII. and XVIII. strengthen Colorado's SIP and State Only provisions, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(VII) The revisions to Regulation Number 7 Sections XII. and XVIII., including the State Only provisions, establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, or qualify for an extension of the attainment deadline, EPA will likely reclassify Colorado as a Serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs. The State Only rule revisions are expected to reduce future costs by achieving emissions reductions that will assist the DMNFR in attaining both the 2008 and 2015 ozone NAAQS thus avoiding additional ozone nonattainment area CAA requirements.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The State Only pneumatic controller inspection program is tailored to be consistent with the SIP required LDAR program, thereby reducing costs related to pneumatic controller inspections.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants. Further, pneumatic controller inspections will be conducted using accepted technologies and some owners or operators already repair and maintain pneumatic controllers.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP. The Commission determined that the Division's proposal was reasonable and cost-effective. The Commission further determined the State Only natural gas-driven pneumatic controller inspection program is reasonable and cost-effective, given the potential for reducing emissions from malfunctioning pneumatic controllers and the absence of federal requirements addressing pneumatic controller emissions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's Ozone SIP to address the Moderate nonattainment area requirements. Colorado must also continue to reduce ozone concentrations to address both the possibility of reclassification under the 2008 ozone NAAQS and the 2015 ozone NAAQS. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, including regulatory changes made on a State Only basis, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

Q. July 19, 2018 (Sections XVI. and XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e. sources that emit or have the potential to emit 100 tons per year ("tpy") or more). The CAA does not define RACT. However, EPA has defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53762 (Sept. 17, 1979). RACT can be adopted in the form of emissions limitations or work practice standards or other operation and maintenance requirements as appropriate.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions.

In response to the reclassification, the Commission revised Regulation Number 7 to satisfy RACT SIP requirements for Moderate nonattainment areas by establishing categorical RACT requirements for major sources of VOC and/or NOx in the DMNFR. Specifically, the Commission adopted RACT requirements in Section XVI.D. for existing boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces, and compression ignition reciprocating internal combustion engines ("RICE") (collectively referred to as "stationary combustion equipment") located at major sources of NOx in the DMNFR as of June 3, 2016.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Major VOC and NOx source RACT

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. The following sources were known by the Commission to be major sources of VOC and/or NOx as of June 3, 2016 and were analyzed in Colorado's Moderate Area SIP for the 2008 8-Hour Ozone NAAQS:

Anheuser-Busch, Fort Collins Brewery (069-0060) and Nutri-Turf (123-0497) (major for VOC and NOx)

Ball Metal Beverage Container Corporation (059-0010 major for VOC)

Buckley Air Force Base (005-0028 major for NOx)

Carestream Health (123-6350 major for NOx)

Cemex Construction Materials (013-0003 major for VOC and NOx)

Colorado Interstate Gas, Latigo (005-0055 major for NOx)

Colorado Interstate Gas, Watkins (001-0036 major for VOC and NOx)

Colorado State University (069-0011 major for NOx)

CoorsTek (059-0066 major for VOC)

Corden Pharma Colorado (013-0025 major for VOC)

DCP Midstream, Enterprise (123-0277 major for VOC and NOx)

DCP Midstream, Greeley (123-0099 major for VOC and NOx)

DCP Midstream, Kersey/Mewbourn (123-0090 major for VOC and NOx)

DCP Midstream, Lucerne (123-0107 major for VOC and NOx)

DCP Midstream, Marla (123-0243 major for VOC and NOx)

DCP Midstream, Platteville (123-0595 major for VOC and NOx)

DCP Midstream, Roggen (123-0049 major for VOC and NOx)

DCP Midstream, Spindle (123-0015 major for VOC and NOx)

Denver Regional Landfill, Front Range Landfill, Timberline Energy (123-0079 major for NOx)

Elkay Wood Products (001-1602 major for VOC)

IBM Corporation (013-0006 major for NOx)

Kerr-McGee Gathering, Frederick (123-0184 major for VOC and NOx)

Kerr-McGee Gathering, Hudson (123-0048 major for VOC and NOx)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057 major for VOC and NOx)

Kodak Alaris (123-0003 major for VOC)

Metal Container Corporation (123-0134 major for VOC)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery, Rocky Mountain Metal Container (059-0006), MMI/EtOH (059- 0828), and Colorado Energy Nations Company, LLC (059-0820) (major for VOC and NOx)

Owens-Brockway Glass (123-4406 major for NOx)

Phillips 66 Pipeline, Denver Terminal (001-0015 major for VOC)

Plains End (059-0864 major for VOC and NOx)

Public Service Company, Cherokee (001-0001 major for NOx)

Public Service Company, Denver Steam Plant (031-0041 major for NOx)

Public Service Company, Fort Lupton (123-0014 major for NOx)

Public Service Company, Fort Saint Vrain (123-0023 major for NOx)

Public Service Company, Rocky Mountain Energy Center (123-1342 major for NOx)

Public Service Company, Valmont (013-0001 major for NOx)

Public Service Company, Yosemite (123-0141 major for NOx)

Public Service Company, Zuni (031-0007 major for NOx)

Rocky Mountain Bottle Company (059-0008 major for NOx)

Sinclair Transportation Company, Denver Terminal (001-0019 major for VOC)

Spindle Hill Energy (123-5468 major for NOx)

Suncor Energy, Commerce City Refinery Plants 1, 2, and 3 (001-0003 major for VOC and NOx)

Thermo Cogeneration, JM Shafer (123-0250 major for NOx)

Tri-State Generation, Frank Knutson (001-1349 major for NOx)

TRNLWB, LLC (Trinity Construction Materials, Inc.) (059-0409 major for NOx)

University of Colorado Boulder (013-0553 major for NOx)

WGR Asset Holding, Wattenberg (001-0025 major for VOC and NOx)

Many of the major sources listed above are subject to regulatory RACT requirements. Some of the sources or source emissions points are subject to regulatory RACT requirements in Colorado's SIP; other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement of inclusion of an applicable federal New Source Performance Standards ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado must include in the SIP, provisions to implement RACT for Colorado's major sources. During the November 17, 2016 rulemaking, the Commission adopted source specific RACT for a number of major sources of VOC and/or NOx (again greater than or equal to 100 tons per year) in the DMNFR. These were originally adopted as Sections XIX.C.-XIX.G. for stationary combustion turbines, stationary internal combustion engines, wood furniture manufacturing, and municipal landfills, respectively, during the November 17, 2016 rulemaking. These sections have changed to Sections XVI.D.4.b. and XIX.A.-D. during this July 19, 2018 rulemaking, where requirements for stationary combustion turbines were removed and consolidated into Section XVI.D.4.b. The original Section XIX.C.-XIX.G. RACT requirements became effective on January 1, 2017. However, during the November 17, 2016 rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Regulation 3, Part F. Therefore, the Commission opted to adopt RACT for Colorado's existing major sources of NOx on a categorical basis in this July 19, 2018 rulemaking.

Establishing RACT on a categorical basis is a distinctly different process from Colorado's minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process), and the designs of which can more easily accommodate changes prior to construction. Categorical RACT applies much more broadly to source category, including both existing sources/equipment and new/modified sources/equipment. This inclusion of existing equipment significantly impacts costs, as those sources are not already committed to a capital expenditure and any associated shut down to add controls. This ultimately impacts the decision on what controls are determined to be reasonably available, technologically and economically feasible for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement.

To determine RACT on a categorical basis, the Commission required specific owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NOx emissions from the facility or emission point(s), propose RACT for that facility or point(s), propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). The following major sources were required to submit RACT analyses:

Anheuser-Busch (069-0060) – emission points equal to or greater than 2 tpy VOC or 5 tpy NOx

Buckley Air Force (005-0028) – engines and engine test cell (pt 102, 103, 104, 105, 101)

Carestream Health (123-6350) – boilers (pt 004)

Colorado Energy Nations Company, LLC (059-0820) – boilers (pt 001, 002)

Colorado Interstate Gas, Latigo (005-0055) – engines (001, 011)

Colorado Interstate Gas, Watkins (001-0036) – engines (001, 002)

Colorado State University (069-0011) – boilers (pt 003, 005, 007, 013)

IBM (013-0006) – engines and boilers (pt 088, 090, 001, 011, 095)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057) – turbine (pt 052) and engines (pt 038 through 044, and 047 through 049)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery (059-0006) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

MMI/EtOH (059-0828) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Nutri-Turf (123-0497) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Owens-Brockway (123-4406) – emission points with emissions equal to or greater than 5 tpy NOx (pt 001-023, 025)

Public Service Company, Cherokee (001-0001) – turbines (pt 028, 029)

Public Service Company, Fort Saint Vrain (123-0023) – turbines (pt 010, 011, 001)

Public Service Company, Denver Steam Plant (031-0041) – boilers (pt 001, 002)

Public Service Company, Zuni (031-0007) – boilers (pt 001, 002, 003)

Public Service Company, Fort Lupton (123-0014) – turbines (pt 001, 002)

Public Service Company, Valmont (013-0001) – turbine (pt 002)

Rocky Mountain Bottle (059-0008) – glass melt furnaces (pt 001)

Suncor (001-0003) – boilers (pt 309, 019, 021, 023)

Tri-State Generation and Transmission, Frank Knutson (001-1349) – turbines (pt 001, 003)

TRNLWB, LLC (Trinity Construction Materials) (059-0409) – shale kiln (pt 001)

University of Colorado (013-0553) – Power House and East District – boilers (pt 001, 002, 012, 013) and Williams Village– boilers (pt 016, 017)

WGR Asset Holding, Wattenberg (001-0025) – boiler (pt 012), turbine and duct burner (pt 021) and engines (pt 004 and 018)

Based on the information provided in these RACT analyses as well as the Division's own in-depth review of rules adopted by Moderate nonattainment areas in other states and EPA guidance such as the RACT/BACT/LAER Clearinghouse, the Commission adopted RACT requirements in Section XVI.D. for stationary combustion equipment located at existing major sources of NOx in the DMNFR. The requirements of Section XVI.D. only apply to existing stationary combustion equipment located at sources in the DMNFR that were major for NOx as of June 3, 2016 (i.e. the effective date of the DMNFR's reclassification to Moderate nonattainment).

Definitions

The definition for "stationary combustion equipment" refers to individual emission points and not grouped emission points.

Emission limitations and operational requirements

The Commission adopted categorical emission limitations (Section XVI.D.4.), which vary based on fuel type and size of the stationary combustion equipment, where applicable. Affected stationary combustion equipment is required to comply with these exemptions by October 1, 2021. This compliance period is necessary in order to allow affected sources sufficient time to complete any capital expenditures, install any control or monitoring equipment, and/or satisfy any permitting requirements necessary to comply with the applicable emission limitation. The heat input size threshold for determining whether an emission limitation applies refers to the maximum design value of the stationary combustion equipment. De-rated heat input is not the equivalent of maximum design value heat input. Therefore, stationary combustion equipment cannot simply de-rate to fall below the size threshold. For certain categories of stationary combustion equipment, if the equipment's heat input is below the applicability threshold for the emission limitations, then the equipment would still be required to comply with the combustion process adjustment requirements originally adopted by the Commission during the November 17, 2016 rulemaking (now in Section XVI.D.6.) The compliance date for the categorical emission limits (i.e. XVI.D.4 and XVI.D.5) is independent of the compliance date for the combustion process adjustment (i.e. XVI.D.6(b)(vi)(A)).

The combustion process adjustment requirements shall apply as RACT to a particular piece of equipment in accordance with the applicability provision, Section XVI.D.6.a., regardless of whether or not that piece of equipment is subject to a categorical emission limit in Section XVI.D.4. As described in Section XVI.D.6.a., the combustion process adjustment requirements only apply to stationary combustion equipment with uncontrolled actual emissions of NOx equal to or greater than 5 tons per year located at major sources of NOx. For stationary combustion turbines, the heat input capacity threshold for the emission limitations takes into account to the heat input capacity of the stationary combustion turbine only and not the heat input capacity of the stationary combustion turbine and any duct burner that may be used.

For glass melting furnaces at major sources of NOx, the Commission adopted a production-based categorical emission limitation (Section XVI.D.4.d.). Emissions from some glass melting furnaces are routed through a common stack, where total emissions from multiple furnaces are monitored on a continuous basis. Where this is the case, the total emissions, as monitored from the common stack, shall be divided by the total glass production from all glass melting furnaces associated with the common stack to demonstrate compliance with the categorical RACT limit.

Exemptions

The Commission determined several exemptions from compliance with the categorical RACT standards to be appropriate for Colorado's source mix. In Section XVI.D.2.a., the Commission adopted a 20% capacity factor exemption for boilers and a 10% capacity factor exemption for stationary combustion turbines and compression ignition reciprocating internal combustion engines. The Commission established the 20% and 10% capacity factor exemptions, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units. The Commission determined that the capacity factor exemptions addressed each of these concerns, and thus that additional individual exemptions were not necessary beyond the capacity factor exemption.

At low capacities, controls are often cost prohibitive or technologically infeasible. The Commission determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the categorical standard or monitoring requirements. Many of the older boilers are not equipped with continuous emission monitoring systems ("CEMS") and may require add-on controls to comply with the categorical standard. The shift in capacity to newer, lower emitting boilers which are already equipped with NOx controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption for boilers provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall environmental benefit.

Some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating ("MCR"). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular low utilization boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard.

The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard runs contrary to the original intent of reducing emissions, thus the Commission concludes that it is reasonable to allow exclusion of limited-use boilers from the categorical standard and associated CEMS requirements, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with the categorical standard. Consequently, the Commission determined that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.

For stationary combustion turbines and compression ignition RICE, a 10% capacity factor exemption from the proposed categorical emission standards and monitoring requirements is appropriate because combustion turbines and compression ignition RICE are more likely to operate during the summer months. Moreover, for turbines and compression ignition RICE that are used primarily for emergency power generation or peak demand, historic capacity factors are extremely low (0%-5%), and a 10% capacity factor exemption will provide enough operational flexibility to respond to emergency and peak demand events.

Separately, the categorical RACT for glass melting furnaces provides a 35% low usage allowance similar to capacity factor.

The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input. Alternatively, for electric generating units, the proposal allows for capacity factor to be determined based on electric output, which is consistent with the federal Acid Rain Program.

The Commission intended that the exemption for stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx was based on the permitting threshold in Regulation 3. Similarly, this equipment was not exempted from having to undergo a RACT analysis. The owner or operator must use the most recent air pollution emission notice ("APEN") submitted to the Division to determine total uncontrolled actual emissions.

Stationary combustion equipment that meets one of the exemptions contained in Section XVI.D.2. is not required to comply with the emission limitations, the compliance demonstration requirements and the related recordkeeping and reporting requirements contained in Sections XVI.D.4., XVI.D.5., XVI.D.7., and XVI.D.8., except for XVI.D.7.g, which requires a source that qualifies for an exemption under Section XVI.D.2., to maintain records demonstrating an exemption applies. All stationary combustion equipment is subject to some level of recordkeeping and may also be subject to combustion process adjustment requirements.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of Section XVI.D. as expeditiously as practicable but no later than 36 months after the equipment is no longer exempt. Therefore, if any stationary combustion equipment has to undertake a capital expenditure, such as installing a CEMS, in order to comply with Section XVI.D., then they have up to a maximum of three years to come into compliance. However, if no such capital expenditure or change in operational practice is required, then the stationary combustion equipment should comply sooner than three years (i.e. as expeditiously as practicable.) Additionally, once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations. This means that a source can fall into and out of having to comply with the emission limitation, monitoring, recordkeeping and reporting requirements of the rule if they satisfy the performance test requirements (i.e. the Division will not follow a "once in/always in" approach with respect to emission control requirements of exemptions.) Similarly, this 180-day period starts once the equipment is no longer exempt.

Monitoring, recordkeeping and reporting requirements

The Commission determined that affected stationary combustion equipment comply with certain monitoring, recordkeeping and reporting requirements by October 1, 2021. In order to provide clarity and regulatory certainty, many of the monitoring requirements adopted by the Commission incorporate by reference existing federal requirements and are consistent with rules in Moderate nonattainment areas in other states establishing RACT for these source categories.

The Commission is requiring CEMS or continuous emissions rate monitoring systems ("CERMS") for boilers with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, lightweight aggregate kilns with a maximum heat input design capacity equal to or greater than 50 MMBtu/hr, and glass melting. CERMS may require a stack gas flow rate monitor, where necessary, in order to measure volumetric flow rate and mass emissions. Where stack gas velocity is extremely low, as may be the case for a glass melting furnace, flow can be measured using a Division approved calculation methodology if flow cannot be accurately measured using traditional differential pressure or ultrasonic flow measuring devices. Moreover, where measuring emission rates in terms of emissions per unit of heat input (i.e. lb/MMBtu), EPA Method 19 calculations may be used using the appropriate F factor (i.e. the ratio of combustion gas volumes to heat inputs).

Further, it is the Commission's intent to allow electric utility boilers and stationary combustion turbines subject to the Acid Rain Program to use the quality assurance/quality control and data validation procedures in 40 CFR Part 75 for monitoring emissions to satisfy monitoring, recordkeeping and reporting requirements in this rule. Affected units that are subject to a NOx emission limitation in an NSPS and use CEMS or CERMS to monitor compliance with that limit can use those monitoring, recordkeeping and reporting requirements to demonstrate compliance with this rule.

Similarly, owners or operators of stationary combustion turbines using performance testing to demonstrate compliance with NOx emission limitations of NSPS GG or KKKK may utilize those procedures for demonstrating compliance with the emission limitation in this rule. Where an initial performance test has already been conducted to determine compliance with NSPS GG or KKKK, it is not expected that another initial performance test must be performed for purposes of demonstrating compliance with Section XVI.D. Where an initial performance test has not been previously conducted, it must be completed by October 1, 2021 to demonstrate compliance.

For each initial or periodic test, sources should calculate the backup fuel's heat input for the calendar year prior to the year in which the performance test is required to determine if a test is required for each fuel or only for the primary fuel. Moreover, periodic performance tests must be conducted no more than 24 months apart.

With respect to the fuel flowmeter requirements, the Division reserves the right to audit quality assurance procedures with respect to manufacturer's instructions. The heat input measured and recorded by the fuel flowmeter is to be in the same unit of measurement as the applicable emission limitation. With respect to the quarterly or semi-annual reporting requirement, the Commission intended to only require that reports be submitted no less than semi-annually, but a source may submit quarterly reports in order to be consistent with existing reporting frequencies established in a permit and/or applicable NSPS or NESHAP.

With respect to the performance test reports, all performance test reports must compare average emissions determined by the performance test with the applicable emission limitation using the same number of significant figures as the emission limitation.

Incorporation by Reference in Sections XIX. and XVI.

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Sections XVI.D.5. and XIX.A. through D. by reference.

Additional Considerations

Colorado must revise its ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC and NOx in Colorado's ozone nonattainment area. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission adopted RACT requirements in Section XVI.D. for combustion equipment located at major sources of NOx in the DMNFR. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS Db, NSPS GG, NSPS KKKK, NSPS IIII, NSPS JJJJ, NSPS OOOO, NSPS OOOOa, and the compliance demonstration requirements in 40 CFR Parts 60 and 75 may apply to such stationary combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to specific existing stationary combustion equipment in the DMNFR.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in certain NSPS and MACT. Certain stationary combustion equipment with a lower heat input may trigger the combustion process adjustment work practice requirements of this rule.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7, Sections XVI. and XIX. establish categorical RACT for major sources of VOC and/or NOx, and thus are necessary to satisfy RACT SIP requirements for Moderate nonattainment areas and are specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The Revisions to Regulation Number 7, Sections XVI., and XIX. establish reasonable equity for major sources of VOC and/or NOx by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a 1-year clean data extension), EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal additional monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC and/or NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

R. November 15, 2018 (Sections I., II., VI., VIII., IX., X., XII., XIII., XVI., XVII., XIX., XX., and XXI.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable marginal attainment deadline and therefore reclassified the DMNFR area to moderate, effective June 3, 2016.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 100 tons per year ("tpy") or more) and VOC source categories addressed by an EPA Control Techniques Guideline ("CTG").

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

In November 2016, the Commission determined that some major sources and CTG VOC source categories were adequately addressed under existing SIP requirements. The Commission also adopted new requirements for some major sources and CTG VOC source categories. In November 2017, the Commission adopted categorical RACT requirements for the oil and gas industry in response to EPA's Oil and Gas CTG. In July 2018, the Commission adopted categorical RACT requirements for combustion equipment at major sources that the Commission determined in 2016 were not addressed by SIP RACT requirements.

In this rulemaking, the Commission adopts SIP requirements that further support and complete Colorado's obligation as a moderate ozone nonattainment area to revise Colorado's SIP to include provisions that implement RACT for all major sources of VOC and/or NOx and for all CTG VOC source categories in the DMNFR ozone nonattainment area. Specifically, the Commission adopts categorical RACT requirements for major source breweries, wood furniture manufacturing, and addresses EPA concerns with the industrial cleaning solvent, metal furniture surface coating, and miscellaneous metal surface coating requirements. The Commission also revises specific rule or reference methods incorporated by reference to add applicable citation dates. Last, the Commission adopts specific revisions in a SIP clean-up effort.

Further, the Commission corrects typographical, grammatical, and formatting errors found throughout Regulation Number 7.

Major source RACT

Colorado has major sources of VOC and/or NOx in the DMNFR. Under marginal and moderate ozone nonattainment classifications, major sources are sources with the potential to emit greater than or equal to 100 tpy of NOx or VOC. Many of the major sources analyzed in 2016 were already subject to regulatory RACT requirements in Colorado's SIP, individual RACT requirements established in federally enforceable permits as a minor source RACT requirements, or an applicable federal New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutant ("NESHAP"). However, as a moderate nonattainment area, Colorado must include provisions in the SIP to implement RACT for Colorado's major sources. In November 2016, the Commission directed some major sources to submit RACT analyses to the Division, including two major source breweries. The Commission adopts in this November 2018, rulemaking categorical RACT requirements for major source brewing activities.

Major source breweries

The Commission adopts RACT requirements for owners and operators of breweries producing malt beverages and their brewery related operations at a major source VOC as of June 3, 2016, located in the DMNFR. In a moderate ozone nonattainment area, a major VOC source is one that emits or has the potential to emit greater than 100 tpy VOC. A brewery includes brewhouse, fermentation, aging, and/or packaging operations. Brewery related operations include operations that support the production of malt beverages such as wastewater management, container manufacturing, and ethanol distillation. The Commission established RACT for combustion equipment, including at breweries, in July 2018, in Regulation Number 7, Section XVI. The Commission now adopts a process loss limit and pollution prevention requirements for brewery packaging operations. These pollution prevention provisions include performance metrics to reduce product loss, operator training, and packaging equipment to reduce container breakage and product loss. The Commission also adopts wastewater management and treatment requirements for land application of wastewater. Lastly, the Commission adopts requirements for owners or operators to keep records of production, pollution prevention activities, and wastewater to demonstrate compliance with the operational requirements.

The largest VOC emissions sources inside a brewery are associated with packaging operations, including can, bottle, and other container fillers. Breweries can reduce VOC emissions by optimizing packaging operations. The process loss limitation is representative of packaging and filling optimization and, therefore, is an indicator, and potential driver, of the resulting VOC emission reductions. The process loss limitation does not include the railcar loading of beer concentrate that is shipped off-site for packaging. In this process, empty railcars are filled with beer concentrate held in beer concentrate receiving tanks after the aging process. The process loss from the automated loading of the beer concentrate from tanks into railcars is minimal and emissions from the filling of cans, bottles, kegs, or other containers are included with the emissions of the off-site packaging facility.

The process loss is calculated on calendar month and rolling 12-month bases across all packaging operations (i.e., filling lines), which aligns with existing product tracking programs. Process loss equates to the difference in the quantity of malt beverage metered at the filler and the quantity in containers as tracked for the Alcohol and Tobacco Tax and Trade Bureau ("TTB"). Operators determine the average calendar month process loss by comparing the total volumes metered at the fillers to the total volume counted by the TTB case counters. Owners or operators will then determine monthly average process loss percentage by dividing the difference in meter and case counter values by the total volume metered at the fillers. Utilizing an average process loss limit also allows for variations in individual line or brand product loss due to specialty brands or innovative containers. The brewing industry is seeing decreased sales of high-volume brands and increased consumer demand for small-volume unique or complex brands. This market change impacts process loss as the high-volume brands have low process loss values whereas specialty brands often result in higher process loss values due to brand recipe complexity, brand mix complexity, and production schedule complexity. The packaging of more types of brands and more complex brands result in higher process loss values because of differences in recipes that require more time for the filler to adjust to the appropriate fill level, more frequent product change-overs of the filling lines, and more unique packaging. The requirement to completely flush a filling line between brands also increases process loss values when the specialty brands are produced in lesser quantities than high-volume brands. Further, bottle filling lines often have different process loss values than can filling lines, therefore the change in container demand can impact the overall process loss. The average process loss limit of 6 percent on a calendar month and 4 percent on a 12-month rolling average leaves the necessary margin for variability and innovation, while still providing an indicator of RACT-level control of brewery packaging operations VOC emissions.

The Commission exempts from the process loss, pollution prevention, and recordkeeping requirements emissions units' subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 and emission units with total uncontrolled actual VOC emissions less than two tons per year. The first exemption was adopted to avoid subjecting sources to overlapping, duplicative, or contradictory RACT requirements. The second exemption was adopted for consistency with other major source RACT provisions and the use of Colorado's permitting thresholds for NOx and VOC to identify the emission points at major sources for which Colorado evaluated RACT.

The Commission also exempts equipment or activities related to research and development and newly installed, upgraded, or replaced packaging operations. Research and development activities include testing different recipes and packaging types before a product is distributed into commerce. The six-month startup exemption for newly installed, upgraded, or replaced packaging operations allows for the testing and adjustment of the new equipment to meet performance requirements. Examples of newly installed, upgraded, or replaced packaging operations include a new filling line or an upgraded or replaced man-to-machine-interface. Startup of newly installed, upgraded, or replaced packing operations does not include the startup or changeover of malt beverages or new recipes. Quality assurance teams follow a statistical process to verify that equipment is meeting quality standards prior to releasing salable product. These processes may include additional container testing, product sampling, or additional filler flushes while packaging operations are fine-tuned to meet key performance indicators. The volume of the product metered at the filler during the research and development and startup processes is excluded from the monthly process loss calculations. However, new, upgraded, or replaced packaging operations are not exempt from employees training requirements to ensure that employees understand the new packaging operations after startup.

Pollution prevention provisions also include the use and operation of packaging equipment to reduce container breakage and product loss. The Commission exempts from the automated filling equipment requirements packaging operations at pilot brewery operations. Automated filling equipment may be mechanical with a set fill quantity or electric with a flow meter and adjusting fill quantity. Both processes improve consistency, reduce spillage and product loss, and reduce the variation that may occur from human error.

The automated filling lines also include fill level detectors that will reject inadequately filled containers for recovery and recycling. A pilot brewery operation may serve the purposes of research and development but can also be utilized to produce very small quantities of product that is distributed into commerce. Pilot brewery operations can include different filling operations (e.g., bottles, kegs) but may use some manual filling related processes instead of automated processes. The use of manual processes is consistent with industry practices for operations of this small size, less than 50,000 barrels per year, and provides flexibility to account for production variations that may occur during research and development or small batch production.

Wood furniture manufacturing

In 2016, the Commission determined that only one source in the DMNFR exceeded the Wood Furniture CTG applicability threshold, and that source was a major source of VOC. Therefore, the Commission incorporated by reference requirements in 40 CFR Part 63, Subpart JJ (National Emission Standards for Wood Furniture Manufacturing Operations) into the SIP for wood furniture surface coating operations. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could streamline their RACT analysis by relating MACT controls to VOC RACT considerations. However, EPA has since expressed concerns that the NESHAP JJ volatile hazardous air pollutant (“VHAP”) coating content limits may not adequately address coating VOC emissions. The Commission therefore removes the incorporation by reference of NESHAP JJ for wood furniture manufacturing operations in Section XIX. and is instead including the CTG recommended coating VOC content limits and work practices in Section IX.O.

The coating VOC content limits apply to sealers, topcoats, acid-cured alkyd amino vinyl sealers, or acid-cured alkyd amino conversion varnish topcoats. EPA’s Wood Furniture CTG does not define acid-cured topcoats or sealers but does describe acid-catalyzed finishes as the most common catalyzed finishes. The Wood Furniture CTG further states that the film-forming resins in these finishes are usually a urea-formaldehyde or melamine-formaldehyde prepolymer mixed with an alkyd resin that serves as a plasticizer. Common catalysts contained in the acid-catalyzed finishes include sulfuric acid and p-toluenesulponic acid and film formation occurs through curing (polymerization) of the resins rather than drying.

SIP Clean-up

Industrial Cleaning Solvent

In 2016, the Commission adopted provisions in Regulation Number 7, Section X. to include RACT requirements related to the use of industrial cleaning solvents. The Commission adopted several exemptions recommended by EPA’s Industrial Cleaning Solvents CTG as well as exemption for sources complying with cleaning solvent requirements in a federally enforceable NSPS, NESHAP, Best Available Control Technology requirement, or Lowest Achievable Emissions Rate requirement, which was similar to an EPA approved exemption in Colorado’s Regional Haze SIP. EPA has since indicated concerns with approving this broad exemption due to a perceived lack of specificity. The Commission therefore removes the broad exemption in Section X.E.4.a.(i).

Metal furniture and miscellaneous metal surface coating

EPA published Metal Furniture CTGs in 1977 and 2007 and Miscellaneous Metal Parts and Products CTGs in 1978 and in 2008. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could conclude that sources already addressed by RACT determinations for a previous ozone NAAQS do not need to implement additional controls because a new RACT determination would result in the same or similar control technology as the initial RACT determination and any incremental emissions reduction from the application of a second round of controls would be small and the cost unreasonable.

Therefore, in 2016 the Commission relied on the RACT provisions relating to the 1977 and 1978 CTGs adopted into Regulation Number 7, Sections IX.H. and IX.L. in 1978 and 1980 to continue to establish RACT for metal furniture and miscellaneous metal coating operations. EPA has since indicated concerns with the existing provisions due to a lack of specified application technique. The Commission therefore revises Section IX. to specify the use of good air pollution control practices, including efficient application methods.

1990 and 1991 RACT Reports

In 1990, the Commission adopted one of several requirements in Regulation Number 7, specifically Sections I.B.2.f. and I.B.2.g., for existing sources to address EPA concerns with the design, implementation, and enforceability of Colorado's previously submitted and approved Ozone SIP. The provisions included one-time reporting requirements concerning source emissions and RACT for sources existing as of 1989. The provisions were not an ongoing reporting requirement potentially necessary for monitoring compliance with applicable emissions limits. EPA approved these provisions into Colorado's SIP in 1995, without discussion. Due to these one-time requirements having passed and Colorado's major stationary sources being subject to RACT requirements in Regulation Number 7, as adopted by the Commission through 2018, the Commission removed these historic provisions. Removal of these provisions does not remove or modify any control measures, therefore does not affect emissions nor interfere with attainment or reasonable further progress. Where information in the Sections I.B.2.f. and I.B.2.g. reports informed RACT requirements under Section II.C., sources remain subject to applicable RACT requirements and any emission reporting requirements as addressed by the emission statement rule last approved by EPA in 2015 (See 80 Fed. Reg. 50205 (August 19, 2015)).

Incorporation by Reference

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Sections II., VI., VIII., IX., X., XII., XIII., XVI., and XVII.

Additional Considerations

Colorado must revise its Ozone SIP to address the moderate ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC in Colorado's ozone nonattainment area. Colorado's major sources of VOC are subject to various and numerous NSPS or NESHAP, Regulation Number 7 requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC in the SIP. Specifically, the Commission adopted RACT requirements in Section XX. for brewing activities located at major sources of VOC in the DMNFR. The Commission also adopted RACT requirements from EPA's Wood Furniture CTG for wood furniture surface coating in Section IX. MACT JJ may apply to wood furniture surface coating operations.

(II) The federal rule discussed in (I) is primarily technology-based in that it largely prescribes the use of specific coating VHAP contents in order to comply. The federal rule provides flexibility by allowing subject facilities to select any coating meeting the specified VHAP content limits.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP. There is no timing issue that might justify changing this time frame.

(VI) The revisions to Regulation Number 7, Sections IX., X., and XX. establish categorical RACT for major sources of VOC and CTG VOC source categories, and thus are necessary to satisfy RACT SIP requirements for moderate nonattainment areas. The provisions are specific to emission points at sources of VOC, allowing for continued growth at Colorado's sources.

(VII) The Revisions to Regulation Number 7, Sections IX., X., and XX. establish reasonable equity for sources of VOC by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a one-year clean data extension) EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

S. December 19, 2019 (Sections I. through XX. and Appendices A through F – reorganized into Parts A through F)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) Sections 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

<u>Basis</u>

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the Air Quality Control Commission (Commission). This proposed rulemaking focuses on the Air Quality Control Commission directives in Section 25-7-109, CRS, SB19-181 directs the Commission to adopt regulations to "minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx)" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the Commission should consider including semi-annual leak detection and repair (LDAR) inspection requirements at all well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This rulemaking addressed many of the specific provisions for consideration, except continuous methane monitoring, but is only the first of many rulemakings to come in addressing SB 19-181.

Further, on August 15, 2019, the Environmental Protection Agency (EPA) proposed to reclassify the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). See 84 Fed. Reg. 41,674 (Aug. 15, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy and the DMNFR's attainment date becomes July 20, 2021. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Therefore, as a first step to addressing the new statutory directives, and ensuring progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to minimize emissions from the oil and gas sector and to include reasonably available control technology (RACT) requirements for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy. The oil and gas industry is a significant source of VOC, NOx, ethane, and methane emissions, and the Commission expects the industry's growth to continue in the foreseeable future. Improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs, ethane, and methane in a cost-effective manner. These technologies and practices include, without limitation, frequent LDAR inspections, reducing emissions from pneumatic controllers, reducing emissions from the transmission segment, storage tank measurement systems, and vapor collection and return equipment.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO (and NSPS OOOOa) are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both State Implementation Plan (SIP) requirements that apply in the DMNFR and state-only requirements that apply state-wide. In addition, evidence in the rulemaking record supports the conclusion that the rules can be implemented effectively. Accordingly, the Commission concludes that the rules are technologically feasible and cost-effective.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, *et seq.* (Act), specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas operations, including well production facilities and natural gas compressor stations. The Commission expands the inspection and enhanced response program for pneumatic controllers it adopted in 2017 for pneumatic controllers in the DMNFR to a state-wide applicability. The Commission adopts a new, innovative performance based program to reduce emissions from the downstream transmission segment.

The Commission is replacing the system-wide condensate storage tank control strategy in the SIP with a more straight-forward storage tank control threshold. The Commission is also seeking to reduce emissions from storage tank measurement and sampling and loadout activities, and to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission is expanding the requirement to employ best management practices to minimize emissions at oil and gas wells during well plugging activities. The Commission is also establishing an annual emissions inventory report that oil and gas operators will submit to the Division, which will ensure accountability and assist the Commission in understanding the emissions of methane, ethane, VOC, CO, and NOx associated with different activities and equipment in oil and gas operations. The Commission believes that this combination of revisions is appropriate as a first step in minimizing emissions from oil and gas operations and continuing to make progress towards attainment of the ozone NAAQS.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources ($\geq$ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, including categorical RACT requirements, and requiring the submission of RACT analyses.

The Commission is also updating requirements for gasoline transport trucks, bulk terminals, and service stations to align with current federal requirements in a SIP clean-up effort.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Reorganization

Over the years, Regulation Number 7 has grown. In an effort to facilitate readability, and to better allow the regulated community to identify and understand the provisions governing their activities, the Division is proposing a full reorganization of Regulation Number 7 into parts. A table identifying the new section(s) along with the prior section/location is below. This Statement of Basis and Purpose will refer to the reorganized section numbers in the discussion of revisions and new provisions.

Reorganized Regulation Number 7 Section	Regulation Number 7 Section (as of 11/15/2018)
Part A	
Part A, Section I.	I. Applicability
Part A, Section II.	II. General Provisions
Part A, Appendix A	Appendix A. Colorado Ozone Nonattainment or Attainment Maintenance Areas

Part B	
Part B, Section I.	III. General Requirements for Storage and Transfer of Volatile Organic Compounds
Part B, Section II.	IV. Storage of Highly Volatile Organic Compounds
Part B, Section III.	V. Disposal of Volatile Organic Compounds
Part B, Section IV.	VI. Storage and Transfer of Petroleum Liquids
Part B, Section V.	VII. Crude Oil
Part B, Section VI.	VIII. Petroleum Processing and Refining
Part B, Section VII.	XV. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities
Part B, Appendix B	Appendix B. Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks
Part B, Appendix C	Appendix C. Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants (Vapor Balance System)
	Appendix E – deleted, paragraphs B and E moved into section, and references replaced with EPA Method 27

Part C	
Part C, Section I.	IX. Surface Coating Operations
Part C, Section II.	X. Use of Cleaning Solvents
Part C, Section III.	XI. Use of Cutback Asphalt
Part C, Section IV.	XIII. Graphic Arts and Printing
Part C, Section V.	XIV. Pharmaceutical Synthesis
Part C, Appendix D	Appendix D. Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers
Part C, Appendix E	Appendix F. Emission Limit Conversion Procedure

Part D	
Part D, Section I.	XII. Volatile Organic Compound Emissions from Oil and Gas Operations
Part D, Section II.	XVII. (State Only, except Section XVII.E.3.a., which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines
Part D, Section III.	XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations
Part D, Section IV. (State Only) Control of emissions from the transmission and storage segment	NEW
Part D, Section V. (State Only) Oil and Natural Gas Operations Emissions Inventory	NEW

Part E	
Part E, Section I.	XVI.A.-C. (natural gas fired reciprocating internal combustion engines in the 8-hour ozone control area) and XVII.E. (new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines)
Part E, Section II.	XVI.D. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area
Part E, Section III.	XIX. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-Hour Ozone Control Area
Part E, Section IV.	XX. Control of Emissions from Breweries in the 8-Hour Ozone Control Area

Part F	
	XXI. Statements of Basis, Specific Statutory Authority and Purpose

State Implementation Plan Revisions (Part D, Section I. (formerly Section XII.))

The Commission adopted several revisions to the SIP provisions that were previously found in Section XII. While not strictly necessary to comply with a particular CAA requirement pertaining to ozone, the revisions implement the mandate of SB 19-181, strengthen Colorado's Ozone SIP, and will achieve further reductions in ozone precursors and other hydrocarbons.

Applicability (Section I.A)

The Commission revised the applicability language of Part D, Section I. to clarify that all oil and gas operations at and upstream of the natural gas processing plant are subject to the provisions of Section I., as more specifically set forth in Sections I.A through L. The Commission also revised the applicability to ensure that storage tanks containing hydrocarbon liquids (*e.g.*, condensate, crude oil) and produced water are subject to the provisions of Section I., which previously applied only to condensate storage tanks.

Further, under previous provisions, owners and operators of condensate storage tanks for which the APENs reflecting emissions from all operations were 30 tpy VOC or less were exempted from Section I. Given the challenges with attaining the ozone NAAQS, the number of tanks that were exempt under this provision, and the need for further reducing emissions from those tanks, the Commission removed this exemption.

However, the Commission retained the exemption from the system-wide control strategy in Section I.I. (formerly Section XII.I.) for owners or operators of natural gas compressor stations that do not also own or operator exploration and production facilities and the exemption in Section I.G. (formerly XII.G.) for owners or operators of natural gas processing plants. Owners or operators of these facilities must continue to control condensate storage tanks as specified in Sections I.I. and I.G. By retaining these exemptions, the Commission does not intend to exempt these facilities from any applicable requirements in Part D, Section II.

Storage Tank Controls (Section I.D)

In 2004, the Commission adopted the initial system-wide control strategy, which required operators to reduce emissions from their system of condensate tanks. The “system” was comprised of condensate tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy, and allowed operators to decide which tanks to control so long as emissions from the “system” were reduced by specified percentages. The system-wide control strategy involved complicated and often times confusing recordkeeping and reporting. Further, the system-wide control strategy had the unintended impact of disincentivizing operators to build new facilities without storage tanks (a real emissions benefit), because operators could not take credit for the production at tankless facilities in their “system.” As a result, the Commission replaced the system-wide control strategy with a straightforward control threshold. Operators in the 8-hour Ozone Control Area will have until May 1, 2020, (prior to summer ozone season 2020) to install controls on storage tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy. Only the requirements for storage tanks with uncontrolled actual VOC emissions equal to or greater than 4 tpy are included in the SIP, while the requirements for the storage tanks between 2 and 4 tpy will remain state-only. This provision expands the control requirements to crude oil and produced water tanks, and will result in several hundred more tanks being controlled. The Commission has reviewed the evidence and has determined that the 4 tpy SIP threshold and implementation timetable is cost-effective, technically feasible, and will ensure no backsliding as provided for in the Clean Air Act, Section 110(l). In Sections I.D.3.b.(v) and I.D.3.b.(vi)., the Commission has required that storage tanks below the 2 tpy threshold that increase emissions above the threshold must be in compliance with 60 days of the first date of the month after which the threshold was exceeded. As a result, if a storage tank exceeds the 2 tpy threshold in September 2020, based on a rolling twelve-month total (*i.e.*, October 2019-September 2020), the tank must have controls installed and operating within 60 days of October 1, 2020. These provisions will not only minimize emissions from storage tanks but will ensure clarity in the applicability of control requirements and will assist Colorado in making additional progress towards attainment of the ozone NAAQS.

The Commission has also determined that storage tanks that cannot install controls by the applicable compliance date may shut-in all wells producing to the applicable storage tanks, so long as production from any well producing into the storage tank is not resumed until controls are installed. It is the Commission's intent that this allowance not apply unless the operator shuts in all wells feeding in to the storage tank/battery requiring controls. This will avoid the need for operators to install control equipment when wells are shut-in and where the operator may determine not to return those wells to production. Further, the Commission intends that the Division will work with operators in the DMNFR to allow for appropriate time to conduct design analyses to comply with Sections I.C.1.b. and II.C.2.a., as long as operators install required controls by May 1, 2020, and are pursuing compliance with reasonable diligence.

The Commission has also included in the SIP in Sections I.D.2.a. and II.C.1.b.(ii) the existing requirements (formerly Sections XII.D.1. and XVII.C.1.c.) that operators of newly constructed tanks employ controls during the first 90 days after the date of first production (this provision was previously designated state-only). However, these revisions to Regulation Number 7, in conjunction with revisions to Regulation Number 3, use the term "commencement of operation" instead of "date of first production." This SIP revision is not part of Colorado's ozone attainment requirements but is directed at making this requirement enforceable by the EPA and members of the public under the CAA. While the Commission does not believe inclusion of this provision in the SIP was required for compliance with Colorado's permitting program in Regulation Number 3 with CAA requirements, including ozone nonattainment area requirements, pursuant to Section 25-7-105.1(1), CRS, including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purpose of permitting.

Storage Tank Monitoring (Section I.E)

The Commission revised Section I.E. to apply the monitoring requirements to all storage tanks controlled pursuant to Section I.D., which will ensure monitoring not only of condensate tanks, but also of crude oil and produced water tanks on a weekly basis. The required inspections have also been updated to include common-sense elements that can have a real impact on performance of well production facility equipment and can reduce emissions. For example, checking that burner trays are not visibly clogged can improve the performance of air pollution control equipment. The Commission does not intend that operators should shut-in the combustor for the sole purpose of performing this inspection to observe the burner tray, and need only inspect those portions of burner trays that are visible without shutting in. The Commission also adopted into Section I.E. requirements that previously existed in Section II. (formerly Section XVII.) to check that pressure relief valves are properly seated and that vent lines are closed. Similarly, to the inspection in Section II.C.1.d.(i), operators are not expected to disassemble or otherwise manipulate the pressure relief valve to complete the inspection, unless the visual observation of the valve reveals it is unseated and corrective action needs to be taken. Further, the Commission does not expect operators to climb on top of a tank to observe the pressure relief valve. However, operators are expected to use an available catwalk or similar permanent access to ensure the best opportunity for inspection, except when a catwalk is not accessible due to a safety hazard.

The Commission has removed references to recordkeeping from Section I.E. and has attempted to condense all recordkeeping requirements in Section I.F. For example, Section I.E.2.c.(iv) no longer provides that operators must "check for and document" the inspection; instead, Section I.E.2.c. requires operators to "check", and the requirement to "document" the inspection is found in Section I.F.2.c.

Recordkeeping and Reporting (Section I.F)

As a result of replacing the system-wide control strategy with the fixed control threshold, the Commission revised the recordkeeping and reporting requirements for demonstrating compliance with Section I.D. Operators subject to the system-wide control strategy will still be required to submit an annual report for calendar year 2019 by the same deadline of April 30, 2020, and are given until August 31, 2020, to submit the report for the time period in 2020 during which the system-wide control strategy remains effective (*i.e.* January 1 – April 30, 2020). In Sections I.F.2. and I.F.3., the Commission has created a new recordkeeping and reporting scheme for the tanks subject to the new control threshold provisions. The Commission has largely maintained the same recordkeeping and reporting requirements for the monitoring provisions in Section I.E. However, the Commission streamlined the new storage tank recordkeeping and reporting requirements, which are included in the SIP for storage tanks at or above the 4 tpy threshold, but are included on a state-only basis for the storage tanks between 2 and 4 tpy.

Miscellaneous

The Commission adopted revisions to definitions (Section I.B.) and the general provisions (Section I.C.). A new definition for "commencement of operation" was added for consistency with Regulation Number 3 and for clarity as to the applicability of other control requirements (previous versions of Regulation Number 7 were tied to the "date of first production," which was not implemented consistently amongst operators). The Commission adopted the term "date of first production" in 2014 with the intent that it coincides with the date reported to the Colorado Oil and Gas Conservation Commission (COGCC) on COGCC Form 5A. Through implementation of the 2014 revisions, differences between the Commission's and the COGCC's use of the term were realized. Therefore, the Commission has replaced "date of first production" with the more clearly defined "commencement of operation" term.

The Commission also adopted new definitions for "hydrocarbon liquid," "produced water," "storage tank," and "storage vessel" to ensure consistency with the state-only program in Part D, Section II. The definition of "storage tank" referred to the federal definition of "storage vessel" and, therefore, captured crude oil and produced water tanks, in addition to condensate tanks. The federal definition has now been included as a standalone definition of "storage vessel."

The Commission also revised Section I.C.1.b. to reflect that Section I. now applies to oil and gas operations collecting, storing, processing, and handling hydrocarbon liquids and produced water, not just condensate. The Commission replaced the term "leakage" with the term "emission" in order to be consistent with the Common Provisions definition of "emission." The Commission does not intend this latter revision to reflect a change in the meaning or applicability of Section I.C.1.b. (or Section II.B.1.a., where this revision is also made), but only to improve clarity.

The Commission revised Section I.C.2., which specifies how operators must calculate emissions and emission reductions for purposes of demonstrating compliance with the control requirements. These revisions expand the current provisions to storage tanks storing hydrocarbon liquids other than condensate and to storage tanks storing produced water. For crude oil tanks and produced water tanks, operators will need to refer to default emission factors as established and updated by the Division. *See, e.g.* PS Memo 14-03, *Oil & Gas Industry Crude Oil, Condensate and Produced Water Atmospheric Condensate Storage Tanks, Regulatory Definitions and Permitting Guidance for General Permit GP08.*

The Commission has not substantively revised the LDAR SIP provisions of Section I.L. but clarified that applicability is based on emissions on a rolling twelve-month basis, not a calendar year basis. Such was the Commission's intention in adopting the program in 2017.

The Commission has also determined to incorporate Section II.F. (formerly Section XVII.G.) into the SIP. This provision requires control of emissions coming off a separator after a well is newly constructed, hydraulically fractured, or recompleted. These emissions must be routed to a gas gathering line or controlled by air pollution control equipment. This SIP revision is not part of Colorado's ozone attainment compliance requirements, but is directed at clarifying that this requirement is enforceable by the EPA and members of the public under the CAA. Including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purposes of permitting. *See* Section 25-7-105.1(1), CRS.

State-wide, State-Only Revisions (Part D, Section II. (formerly Section XVII.))

In Part D, Section II., the Commission adopted several revisions to begin its implementation of SB 19-181. These revisions further support existing control requirements and also seek reductions from previously unregulated emissions activities (*e.g.,* gauging and loadout).

Storage Tank Controls, Monitoring, Recordkeeping, and Reporting (Sections II.C.1.c., II.C.1.d., II.C.2.b. and II.C.3.)

Since 2011, Colorado has made significant progress in reducing emissions from storage tanks. However, storage tanks remain the largest source not only of oil and gas VOC emissions, but of all anthropogenic VOC emission sources in the state (per the 2017 nonattainment area emissions inventory in the Moderate area ozone nonattainment SIP). The Commission has determined that it is cost effective and technically feasible to lower the control threshold from 6 tpy VOC (as established in 2014) to 2 tpy VOC. However, the Commission does not want to facilitate or encourage the use of supplemental fuel to operate control equipment, and understands that this can occasionally be an issue on the West Slope, in particular, where the facilities have lower pressure. The Commission has therefore adopted a provision that allows operators to seek from the Division an exception to controlling tanks between 2 and 6 tpy VOC under these circumstances. Exceptions should be sought prior to compliance deadlines, and will be effective upon submittal unless and until the Division determines an exception is not appropriate. Storage tanks constructed on or after March 1, 2020, must have controls upon commencement of operation, ensuring reductions during the 2020 summer ozone season. Storage tanks outside the nonattainment area constructed prior to March 1, 2020, must be in compliance by May 1, 2021. The Commission determined it was appropriate to give tanks outside the nonattainment area between 2 and 6 tpy VOC extra time to install controls. The Commission does not intend to give extra time to storage tanks with air pollution control equipment already installed, even where controls are not currently required by Regulation Number 7 (e.g., where an operator has submitted an APEN claiming controls).

The Commission revised the approved instrument monitoring method (AIMM) schedule for inspections of controlled storage tanks to align with the Commission's revision of the LDAR inspection frequencies in response to SB 19-181, discussed further below. The Commission adopted a semi-annual frequency for storage tanks with emissions greater than or equal to 2 tpy and less than or equal to 12 tpy. For storage tanks with emissions greater than or equal to 6 tpy and less than or equal to 12 tpy, this is an increase in inspection frequency from annual to semi-annual. Where the Commission specifies that semi-annual monitoring must "begin" in a certain year, the Commission intends that there be at least two AIMM inspections during that year. The Commission also removed the phase-in schedule for storage tanks inspections (within 90 days of January 1, 2016 for storage tanks ≥ 6 and within 30 days for storage tanks > 50 tpy) as those schedules have passed. The Commission updated the recordkeeping requirements for AIMM inspections to be consistent with the LDAR recordkeeping in Section II.E. Records of AIMM inspections under Sections II.C. and II.E. may be maintained together, and need not be kept separately.

The Commission has also strengthened monitoring requirements for storage tanks and associated equipment. In Section II.C.1.d., the Commission has determined that it is cost effective and feasible, while already on-site for visual inspection, to check the dump valve on the separator to ensure that it is not stuck open or visibly clogged. The Commission does not intend that operators will need to manipulate equipment or stay on-site for the purpose of observing actuation of the dump valve for purposes of this inspection requirement. The Commission has also determined that excess liquids in the vapor lines can cause a multitude of problems, including over pressurization of the tanks or smoking flares. Therefore, the Commission is directing operators to check liquid knockout vessels, when present, unless the vessel is set up to drain automatically, and to drain liquids if above the low-level indication point. If the knockout vessel is not equipped with a liquid level indicator, operators can comply with this requirement by draining the knockout vessel during the inspection. Further, for underground lines and above-ground lines where no knockout vessel is used, operators should establish a procedure by which they evaluate for the presence of liquids in the vapor lines, and drain as necessary. Appropriate operating and maintenance program documents should set forth this procedure so as to provide clarity on how an operator determines draining is necessary. These actions can be taken while the operator is already on-site for the inspections previously required, are consistent with actions the Commission generally understands operators are already taking in the field and therefore, the Commission does not expect these actions to create additional burden.

The LDAR program in Section II.E. (formerly Section XVII.F.) has required remonitoring following repair of a leak (as has Section I.L.). However, Section II.C. did not include an explicit remonitoring requirement following actions taken to address venting from storage tanks. Operators must now confirm that actions taken to address venting were effective through remonitoring. This confirmation must be made within 24 hours of the action taken to address the venting. This requirement does not reflect a timeframe in which the operator may address the venting without incurring liability for the violation. There is currently no regulatory period in which venting will not be considered a violation of Section II.C.2.a., unless the venting is reasonably necessary for one of the reasons expressly contemplated by Section II.C.2.a. Only where the initial emissions observation was observed through AIMM does the success of the response action need to be verified through AIMM. However, the Commission believes that if the venting was found with an IR camera and was addressed while the IR camera operator was on-site, then there is little to no burden to use the IR camera to confirm, for example, an effective seating of the thief hatch upon closure. In Section II.C.3.f., the Commission has established supplemental recordkeeping requirements when venting is observed and addressed.

In Section II.C.3.d., the Commission has strengthened recordkeeping requirements of inspections under Section II.C.1. These recordkeeping requirements are consistent with the recordkeeping required in Section I.F. (formerly Section XII.F.). The Commission has maintained the exemption from recordkeeping under Section II.C.3.b., for instances where venting is reasonably necessary for maintenance, gauging (unless a storage tank measurement system is required under and the operator complies with Section II.C.4.), or safety of personnel and equipment. However, the Commission expects that the emissions associated with these venting events will be reported in the annual emissions inventory.

Storage Tank Measurement Systems (Section II.C.4.)

Historically, operators have needed – for operational purposes – to open the thief hatch on storage tanks in order to sample and measure the level of the liquid to be sold (i.e., to determine quality and quantity). Technology has advanced over the past few years, including, without limitation, the use of Lease Automatic Custody Transfer (LACT) units, automated tank gauges, and the development of API 18.2 (Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods), which allow for the sampling and measurement of liquids without opening the thief hatch. It is the Commission's intention that owners and operators of facilities and tanks constructed after the deadlines in new Section II.C.4. must measure the level of the liquid (e.g., use tank level sensors) and sample the liquids (e.g., check for temperature, BS&W, and other indicia of merchantability) without opening the thief hatch. These storage tank measurement systems can be employed at facilities with and without automation.

Further, a significant number of operators have already deployed such systems at large and small facilities in the DJ Basin, in some cases voluntarily and in some cases as required pursuant to a Consent Decree or Compliance Order on Consent. The Commission notes that a storage tank management system may be different for tanks where liquids are both sampled and measured than for tanks where liquids are not sampled. For example, Commission understands that some produced water tanks are not sampled for quality, and therefore do not need to have equipment to allow for the sampling of the liquids without opening of the thief hatch.

Therefore, the Commission adopted a requirement to employ storage tank measurement systems to determine the quantity of the liquid at well production facilities, natural gas compressor stations, and natural gas processing plants constructed on or after May 1, 2020. Any such facilities that are constructed after January 1, 2021, must have storage tank management systems in place that determine both the quality and the quantity of the liquid. This requirement also applies to storage tanks at existing well production facilities, natural gas compressor stations, and natural gas processing plants that are modified by adding storage tanks. When operators add new storage vessels to existing facilities (e.g., to add capacity because production or throughput is expected to increase), they must outfit the new storage vessels and retrofit the existing vessels in the same battery with a storage tank management system. However, the ability to retrofit an existing battery may not exist, and is therefore not required, where a single storage tank is replaced due to maintenance concerns or where a tank is installed to provide extra head space in the vapor control system, but no production increase is associated with the installation.

The Commission has adopted minimal recordkeeping provisions for this requirement, including a description of the storage tank measurement system and records of the annual training program. The description must be sufficiently detailed to enable the Division to determine whether the operator is in compliance (e.g., sampling the liquids without opening the thief hatch). If an operator relies on a third party (e.g., hauler) to perform the gauging activities, those operators will need to work with the haulers to facilitate the training that will familiarize haulers with this new requirement.

The Commission has also adopted a requirement to allow for periodic calibration and testing of the storage tank measurement system. The Commission recognizes that while the Bureau of Land Management expressly allows for automatic tank gauging (*see e.g.* 42 C.F.R. Section 3174.3(33), incorporating by reference API 18.2), it can be necessary to test and calibrate the automatic tank gauging system. *See* 42 C.F.R. Section 3174.6(b)(5)(ii)(B). It is not the Commission's intent to adopt requirements at odds with the Bureau of Land Management. Further, some manufacturers may recommend inspection, testing, or calibration more frequently than specified by the Commission; the Commission intends to allow for those maintenance procedures, as reasonably necessary (i.e., the exception should not render ineffective the Commission's intent that thief hatches remain closed during the sampling and measurement process). Operators that perform maintenance procedures more frequently than semi-annually need to document the manufacturer's recommendation for the increased frequency and provide those materials to the Division upon request.

Hydrocarbon Liquids Loadout (Section II.C.5)

In Section II.C.5., the Commission has adopted new requirements to control or avoid emissions associated with the unloading of hydrocarbon liquids into transport vehicles (e.g., trucks). These requirements do not apply to produced water loadout. The Commission has determined to prohibit the venting of hydrocarbons during loadout activities, because the venting is not reasonably necessary within the meaning of Section II.C.2.a.; however, the Commission notes that some thief hatches may be "open" during loadout but are not emitting and are instead operating only as vacuum relief for the storage tank. An "open" pressure relief device that does not emit, but instead creates a vacuum, would not be a violation of the prohibition on venting during loadout, though the burden will remain on operators to demonstrate that any open pressure relief devices are not venting.

These requirements will apply to well production facilities, natural gas compressor stations, and natural gas processing plants constructed before and after May 1, 2020, with annual hydrocarbon liquid loadout throughput equal to or greater than 5,000 barrels per year, on a 12-month rolling basis. Throughput is based on the throughput of liquids loaded out to transport vehicles and does not include liquids loaded out to pipeline. Facilities constructed after May 1, 2020, must control emissions from loadout upon commencement of operation if they anticipate having a loadout throughput over 5,000 barrels per year. Facilities that are modified (e.g., new well drilled, well re-fracked or recompleted) that expect to have throughput over 5,000 barrels per year must also control loadout operations upon commencement of operation following the modification. Facilities that increase throughput such that loadout throughput reaches 5,000 barrels must control the emissions from loadout upon reaching 5,000 barrels. The Commission does not intend that operators may loadout more than 4,999 barrels of hydrocarbon liquids without controls. Thus, if an operator currently loads out to pipeline, and is not subject to this requirement, but the pipeline becomes unavailable (e.g., due to maintenance, whether scheduled or unscheduled) and the operator has 6,000 barrels stored in tanks, the operator must control the emissions from the loadout to transport vehicles or wait to loadout to transport vehicles until it can arrange for controls.

The Commission recognizes that compliance may be more cost effective at newly constructed facilities for several reasons. Operators may account for the vapors associated with loadout in the initial evaluation of air pollution control equipment required. Operators may also design the facility to make compliance easier, with both these requirements and Section II.C.4. However, the Commission has determined that it is also cost-effective and technically feasible to retrofit existing facilities to control loadout emissions. Operators using air pollution control equipment to control loadout emissions must also comply with other Regulation Number 7 requirements applicable to air pollution control equipment (e.g., inspections, recordkeeping). Further, if operators employ vapor collection and return systems, operators should include this vapor source in the engineering evaluation of their storage tanks and vapor control systems to avoid over-pressurizing the tanks.

The Commission has also established additional requirements to ensure the effective control of loadout emissions, including many requirements that the Division has previously established as permit RACT (under Regulation Number 3 and not as categorical RACT used for ozone SIP purposes) in loadout permits. The Commission determined that observation of and/or training and signage related to the loadout process by operators will help ensure that new staff and third parties are effectively implementing these requirements. The Commission directed the Division to develop a template and/or guidance regarding expectations for signage. However, if tanks are loaded out less frequently than monthly, the observation needs to take place during loadout when it does occur, unless observation is not feasible. If observation is not feasible (e.g., the operator did not receive notice of the loadout, which occurred during the middle of the night when no operator personnel was on site), the operator must inspect the facility within 24 hours to ensure that loadout equipment was properly stored and that thief hatches were closed. The Commission encourages the Division to work with operators to better understand when observation is, or is not, feasible.

Leak Detection and Repair (Section II.E)

In SB 19-181, the Legislature directed the Commission to minimize emissions from the oil and gas sector, including the gathering and boosting segment (i.e., compression). In conjunction with this directive, SB 19-181 further instructed the Commission to consider semi-annual monitoring for leaks at well production facilities. Therefore, the Commission has revised the LDAR program of Section II.E. (formerly Section XVII.F.) to increase the frequency of approved instrument monitoring method (AIMM) inspections to semi-annual at compressor stations with emissions between 0 and 12 tpy VOC and at well production facilities with emissions between 2 and 12 tpy VOC. Phase-in of these new inspections begins in 2020, and the Commission expects that operators will conduct the first semi-annual inspection prior to the start of the summer ozone season (i.e., May 1, 2020). Current requirements in place for larger facilities to inspect on a more frequent basis remain unchanged.

The Commission adopted a proposal to require enhanced leak detection and repair requirements for facilities within 1,000 feet of an occupied structure. The commission also directed the Division to work on a proposal that would speed up repair times in these areas and bring forward for the Commission's consideration in a future rulemaking hearing as soon as possible.

There are no other substantive changes to the existing LDAR program.

Emissions Associated with Well Maintenance, Unloading, and Plugging Activities (Section II.G)

In 2014, the Commission adopted a requirement that operators use best management practices (BMPs) to minimize hydrocarbon emissions and the need for well venting associated with well liquids unloading and well maintenance. The Commission is replacing the term "venting" with "emissions" or "emitting" to ensure consistency with the Common Provisions definition of "emission" and to avoid any confusion with the new definition of "venting" that was added to Section II.C.2.a.(i) (formerly Section XVII.C.2.a.(i)) in 2017, though no change in meaning or applicability is intended. The Commission has determined that BMPs should also be employed to reduce emissions from the well associated with well plugging activities. These activities have been increasing in frequency in the DMNFR in recent years, and the Commission finds that BMPs are a cost-effective and flexible proactive strategy to address this emerging emissions source. BMPs include both practices that reduce the need for well liquids unloading or well maintenance activities and practices that reduce or control emissions resulting from the well maintenance, well liquids unloading, and well plugging activities.

The Commission has also clarified and strengthened the recordkeeping and reporting requirements associated with the well emissions and BMPs. The inventories that will be required to demonstrate attainment with the ozone NAAQS in future SIPs necessitate detailed information on the emissions associated with these activities. Further, understanding BMPs employed to reduce or eliminate these emissions will assist the Commission in developing both voluntary and regulatory strategies to make further progress towards attainment. In an effort to minimize duplication with the new emissions inventory in Section V., the Commission intends that all information associated with activities covered by this Section II.G. will be reported on a separate form and not as part of the Section V. inventory. While recordkeeping is to begin in July 2020, the Commission understands that current methods of reporting emissions from these activities may need to be updated or improved in the future, and the Commission directs the Division to work with stakeholders to update emission factors and/or calculation methods as necessary.

Miscellaneous

Section II.C.2.a. prohibits the venting of hydrocarbons, unless reasonably required for maintenance, gauging, or safety. The Commission now clarifies that venting during gauging is expressly prohibited under this requirement where a storage tank measurement system is required under Section II.C.4. If Section II.C.4. allows for the opening of the thief hatch, that activity will not be considered venting within the meaning of Section II.C.2.a.

The Commission has revised Section II.C.2.b.(i), to reflect its intention in adopting the STEM provisions in 2014. The Commission intended in 2014, and specifically noted in the Statement of Basis and Purpose at that time, that STEM plans should include an analysis of the engineering design of the storage tank and associated air pollution control equipment (i.e., the vapor control system) to ensure that storage tanks are not over pressurized, causing excess emissions. The Commission believes that operators now largely understand and comply with this requirement, but has clarified the language in the rule itself principally to aid operators that may be new to the control program as a result of the new, lower control threshold. The Commission notes that this requirement does not require that operators maintain a site-specific design analysis for each facility. Worst-case design analyses or like-kind design analyses for similarly configured facilities may be utilized; however, the burden remains with the operator to show that the design analysis provided for the facility demonstrates adequacy of design.

Further, the Commission acknowledges that closed-loop tank pressure control systems designed to maintain tank pressures below a specified point can be, if designed and operated property, indicative of adequate design. The Commission also acknowledges that design analyses do not need to be maintained within the STEM plan itself, so long as the STEM plan contains a description of the design analysis method employed and specifies the name and location of the design analysis for each facility covered by that STEM plan.

Pneumatic Controllers (Part D, Section III.)

SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.

The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.

The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings.

Downstream transmission (Part D, Section IV.)

SB 19-181 also directed the Commission to consider adopting a requirement that owners and operators of oil and gas transmission pipeline and compressor stations inspect and maintain all equipment and pipelines. The Commission's Regulation Number 7 has not historically regulated the transmission and storage segment, which includes pipeline, compressor stations, and other equipment transporting and storing natural gas downstream of the natural gas processing plant and prior to the distribution segment. Transmission pipelines, however, have been subject to federal and state pipeline safety regulations.

To address the new directive to minimize emissions from the transmission segment, the Commission adopted an innovative program that directs the setting of a methane intensity target and associated programmatic framework. This approach is the second recommendation from the SHER team, and again comes before the January 2020 deadline established by the Commission in November 2017. SHER team stakeholders involved in developing this program include trade associations, transmission segment operators, environmental and citizen groups, local governments, and the Division. The Division will approve a steering committee charter that will detail the purpose, responsibilities, and deliverables of the steering committee. The steering committee will develop an emissions protocol detailing the calculation and reporting of VOC, CO, NOx, ethane, and methane emissions and any associated program guidance documents or templates by September 30, 2020, determine a segment methane emissions intensity target by October 1, 2023, and certify initial target compliance based on the 2024 data. Each owner or operator in the segment will develop a company-specific best management practice (BMP) plan, the elements of which are enforceable by the Division. A goal of this program is continual improvement over time through review of BMPs, assessment of reported emissions and emissions intensity, and analysis of other data and best practices. In furtherance of this goal, the steering committee will periodically reassess the emissions intensity target and may consider, among other factors, the potential to reduce emissions from events beyond the control of the owner or operator.

The Division will provide an update on the development of the program to the Commission in 2021 as well as periodic updates regarding the progress of the program. The program will include a reporting element to demonstrate compliance and continual improvement. The steering committee will develop the criteria by which the industry participants will select a third-party contractor to collect and aggregate the company-wide reports into the segment-wide report prior to the first report due date of September 30, 2022. The third-party contractor, with involvement from the transmission segment owners or operators, may also provide VOC, NOx, and CO emissions data from the annual company-wide reports to the Division related to ozone modeling as needed and requested. Each year after the segment-wide emissions intensity target is established, the steering committee will submit a compliance certification to the Division that the transmission segment achieved the target. If such certification cannot be made, the steering committee will develop a plan for the segment to achieve compliance with the target. This plan, if needed, may include amendments to the program guidance documents, prescriptive control requirements, or other strategies to reduce methane emissions such that the transmission segment achieves the segment-wide emissions intensity target.

The inventory protocol may be based on existing EPA estimation and reporting mechanisms, specifically the EPA's Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI). The emission estimation mechanisms may be updated as emission factors or calculation methods are revised. The inventory protocol will include the method(s) by which the transmission segment owners or operators will quantify and report emissions. The findings of the Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems (MAC) report (May 2016), among other data sources, may be used to develop the segment-specific methane emission reduction goals that, when combined, will achieve the transmission segment's emission intensity target in a cost-effective manner.

Annual inventory (Part D, Section V)

The Commission established an annual emissions reporting requirement to regularly update the Division's emissions inventory for equipment and activities in oil and gas operations. This inventory is intended to assist Colorado in ozone planning and the creation of emission inventories for use in ozone attainment modeling, as well as to comply with the directives in SB 19-181 to minimize emissions from the oil and gas sector. This inventory will provide missing information about oil and gas operations and will supplement the limited information provided on other aspects of those operations to assist the Commission in identifying emission sources appropriate for further emission reduction strategies.

Additionally, this inventory will also help Colorado move forward in beginning to address the broad greenhouse gas directives in SB 19-096 (Concerning the collection of greenhouse gas emissions data to facilitate the implementation of measures that would most cost-effectively allow the state to meet its greenhouse gas emissions reductions goals) and HB 19-1261 (Concerning the reduction of greenhouse gas pollution, and, in connection therewith stablishing statewide greenhouse gas pollution reduction goals). This inventory is separate and apart from the APEN reporting and fee structure in Regulation Number 3, though the Commission expects that the Division, in consultation with stakeholders, will consider ways to align the reporting programs in the future to minimize duplication.

Operators will be required to submit a company-wide report on June 30 of each year for the preceding year. The first report will be due on June 30, 2021, covering emissions from July 1, 2020, through December 31, 2020. Operators are required to use the Division-approved form. The Commission expects that the Division will consult with stakeholders in the development of this form (or forms). The Commission understands that some of the emissions source category activities and equipment are not currently well defined, nor is there necessarily a well understood method of calculation for emissions (e.g., downhole well maintenance). The Commission therefore directs the Division to work with stakeholders from the adoption of this regulation throughout 2020 to, among other things: (1) appropriately define each emissions source category, activity, and equipment; and (2) identify reasonable methods of calculation for each emissions source category activity and equipment. For some emissions source category activities and equipment, achieving both goals may not be realistic before recordkeeping must begin in July 2020. Therefore, for those limited categories, the Commission expects that the Division will identify parameters that may be reported (e.g., frequency and duration) until such time as the category can be well defined and an appropriate calculation method can be identified. The Commission's intent here applies also to the well emissions reported under Section II.G.

Operators will need to include actual emissions information for various air pollutants, specifically methane, ethane, VOC, CO and NOx, for each emissions source category activity and equipment, as well as company-wide. The Commission has determined that monthly emissions information should be submitted for the summer months (May through September), while emissions for the remaining months can be aggregated into the annual figures. The Commission recognizes that, over time, these emissions inventories are likely to reflect ongoing emission reductions from the industry resulting from both the continued implementation of emission reduction strategies and the refinement of emissions estimation techniques. The Commission also recognizes that the emission estimation techniques used for inventory purposes may differ from regulatory methods for calculating, recording, and reporting emissions under the APEN and permitting program, and intends that such differences will be considered in any enforcement matter. It is critical that these inventories be as accurate and complete as possible, and operators are expected to perform quality assurance on the data prior to submittal. However, these inventories will require the submittal of a large amount of information, so operators are provided with timeframes for correcting information found to contain substantive errors.

The Commission directed the Division to report back to the Commission in 2020 regarding the inventory and progress made.

Ozone State Implementation Plan Revisions for Serious Reclassification (Part C, Section II.F. (new section in former Section X.; Part E, Sections II. and III. (formerly Sections XVI.D. and XIX.)

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the CAA's Serious ozone nonattainment area requirements, as set forth in CAA Sections 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., major stationary sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, to address the CAA Serious RACT SIP requirements, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx (which became major sources as of the effective date of the reclassification to Serious). The revisions include expanding the applicability of the combustion equipment requirements, including the combustion process adjustment requirements, in Section II. to equipment located at facilities with NOx emissions greater than or equal to 50 tons per year; incorporating by reference NSPS and/or NESHAP requirements for specific points at some 50 tpy major sources in Section III.; requiring some sources submit RACT analyses to the Division in Section III.; and a new categorical rule regarding general solvent use in Part C, Section II.F.

Consistent with Senate Bill 19-181, House Bill 19-1261 and Senate Bill 19-096, the Commission directs the Division to propose regulatory recommendations to the Commission in 2020 regarding: pneumatic devices that do not vent gas; continuous emission monitoring; alternatives to combustion for emissions control; enhanced LDAR, especially near occupied dwellings; and other options to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain," Colo. Rev. Stat. Section 25-7-109(10)(a), including "pre-production activities, drilling, and completion," id. Section 25-7-109(10)(c).

To increase transparency and accountability, the Commission further directs that in 2020 the Division explore options for developing a publicly accessible and searchable oil and gas complaint filing and tracking tool, and to accept public input on the development of this tool. The Division will report back to the Commission on its progress in 2020.

SIP streamlining (Part B, Sections IV. and VII. (formerly Sections VI. and XV.) and Appendices B, C, and E)

As a SIP clean-up effort, the Commission adopted revisions to Regulation Number 7, Part B, Sections IV. and VII. and removed Appendix E so the requirements align with current EPA methods and requirements.

In 1980, the Commission adopted requirements in Regulation Number 7, Section IV. requiring an annual pressure test for gasoline transport trucks. Those requirements were based on EPA's Control Techniques Guidelines (CTG) Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (December 1978) and included the test procedures for annual pressure and vacuum testing of gasoline transport trucks, as outlined in Appendix E. In 1980, The Commission also adopted Appendix B which specifies the criteria for controlling vapors from gasoline transfer to storage tanks. Those requirements are based on EPA's CTG Design Criteria for Stage I Vapor Control Systems Gasoline Service Stations (November 1975). EPA approved these provisions into Colorado's SIP in 1995.

Since the publication of EPA's CTGs, EPA has published similar requirements for gasoline transport trucks in EPA's NSPS Subpart XX Standards of Performance for Bulk Gasoline Terminals (40 CFR Part 60, Subpart XX (August 18, 1983, last revised December 19, 2003)); NESHAP R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) (40 CFR Part 63 Subpart R (December 14, 1994, last revised April 6, 2006)); NESHAP Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (40 CFR Part 63, Subpart BBBBBB (January 10, 2008, last revised January 24, 2011)); and NESHAP Subpart CCCCCC National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC (January 10, 2008, last revised January 24, 2011)). These federal standards reference EPA's Method 27, Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test, in contrast to the CTG's pressure-vacuum test.

The Commission adopted provisions to replace the outdated vacuum-pressure test in Regulation Number 7 with the more current EPA Method 27. The Commission also updated the test values in Regulation Number 7, which are based on EPA's CTG but also correspond to the EPA Method 27 test values in EPA's NSPS XX, NESHAP R, NESHAP BBBBBB, and NESHAP CCCCCC. The Commission also revised the recordkeeping and certification requirements in Section IV. to correspond to EPA's Method 27 and federal standards. Lastly, the Commission clarified the requirements for owners or operators using vapor collection systems that such systems must be leak-tight and properly maintained and operated.

These revisions will update Colorado's SIP and align the gasoline transport truck, terminal, and service station control and testing requirements with current EPA NSPS and NESHAP standards.

Miscellaneous

The Commission has also adopted revisions to provisions not discussed in detail above in order to facilitate and align the substantive revisions identified, including revisions to the Applicability in Part A, Section I.A., and exemptions in Part A, Section II.B.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone serious nonattainment area requirements. The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 that are unrelated to the reclassification to serious to update and streamline requirements for gasoline transport trucks, terminals, and service stations to align with current federal requirements; therefore, these revisions do not exceed or differ from the federal act or rules thereunder. Further, the Commission adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Sections II. (except II.C.1.b.(ii) and II.F.), III.F., IV., and V. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including storage tanks, storage tank loadout, fugitive emissions from components, pneumatic controllers, and downstream transmission operations. The proposed revisions also include an annual oil and gas sector emissions inventory report. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, the Greenhouse Gas Reporting Program (GHGRP), and Pipeline and Hazardous Materials Safety Administration (PHMSA) may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks and fugitive emissions components then the NSPS and NESHAP and more facilities and operations than the GHGRP and PHMSA.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (> 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part E, Sections II. and III. to include categorical RACT requirements for combustion equipment at major sources of NOx and incorporate by reference federal standards for specific sources or points. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment. The Commission also revised Regulation Number 7 to include categorical RACT requirements for general solvent use and is not aware of federal rules applicable to general solvent use.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Part D, Sections I. through IV. strengthen Colorado's SIP state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections II.F. recognize practices currently utilized by solvent operations. The revisions to Regulation Number 7, Part E, Sections II. and III. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D, Sections I. through V. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C, Sections II. and Part E, Section II. similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, or if Colorado continues to fail to achieve the NAAQS, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing an annual oil and gas inventory report are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for storage tanks and component leaks. Other revisions reflect changes in industry practice, such as for solvent use. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) The revisions adopted will reduce significant amounts of VOC and methane, addressing both Colorado's ozone problems and making strides to reduce the impact of climate change. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements related to LDAR, pneumatic devices, monitoring, and the transmission segment. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Hundreds of people from across the state submitted written comments on the proposed changes to Regulations 3 and 7. Most of these written comments called for additional regulation of oil and gas operations, to fulfill the directives of SB 19-181, protect public health, and reduce greenhouse gas emissions. Prior to the rulemaking hearing, the Commission held public comment sessions in Rifle, Durango, and Loveland, on December 10, 11 and 16, respectively. Dozens of members of the public spoke at each of these sessions. Many commenters expressed support for the proposed changes to Regulations 3 and 7, citing concerns about risks to health and to the climate from oil and gas emissions. Many commenters at the Rifle and Durango meetings emphasized the need for rules to be applied statewide. Commenters also called on the Commission to develop requirements for continuous monitoring of oil and gas emissions. Some speakers at each comment session expressed concern that the industry was being overregulated, with some on the Western Slope emphasizing that their part of the state was in attainment with ozone standards and expressing concerns with the impact more stringent rules might have on the industry.

T. September 17-18 & 23, 2020 (Part D, Sections II., IV., V., VI. and Part E, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act § 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

<u>Basis</u>

The Commission revised Part E, Section I. to reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) greater than or equal to 1,000 horsepower (hp) on a state-wide basis. The revisions are in response to four distinct directives to secure reductions: Senate Bill 19-181 (SB 19-181); the second implementation period of the Regional Haze Rule pursuant to Clean Air Act Section 169A; progress towards the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb and 2015 ozone NAAQS of 70 pp; and to address nitrogen deposition at Rocky Mountain National Park (RMNP).

The Commission also revised Part D, Sections II.G., IV., and V. to include annual reporting of carbon dioxide (CO_2) and nitrous oxide (N_2O) and Section V. to include additional emissions reporting from class II disposal well facilities. The Commission adopted a new Part D, Section VI. requiring owners and operators of pre-production oil and gas operations to monitor pollution during pre-production (i.e., drilling through flowback) and early-production and to control emissions from pre-production tanks and vessels (i.e., flowback vessels). Lastly, the Commission expanded the requirements in Part D, Section II. to control emissions from hydrocarbon liquids loadout at class II disposal well facilities. These proposed revisions are a next step in addressing the directives of SB 19-181, SB 19-096, and HB 19-1261, building upon revisions adopted by the Commission in December 2019.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, et seq. (Act), specifically § 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations. Sections 25-7-109(1)(a), (2), and (3) authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources; emission control regulations pertaining to NOx, hydrocarbons, and hazardous air pollutants; and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane, and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Purpose

To address SB 19-181, SB 19-096, HB 19-1261, ozone, visibility, and nitrogen deposition, the Commission adopted revisions to Regulation Number 7 that limit emissions from engines, limit emissions from pre-production tanks, reduce emissions from hydrocarbon liquids loadout at class II disposal well facilities, require reporting of emissions from class II disposal well facilities, expand annual reporting to include additional greenhouse gases, and require monitoring at pre-production and early production oil and gas operations. These revisions are all adopted on a state-wide and state-only basis.

Engines (Part E)

The Commission adopted requirements in Part E, Section I. to minimize emissions from natural gas fired RICE. The requirements apply to natural gas fired RICE greater than or equal to 1,000 HP. The requirements are responsive to SB 19-181 as it applies to engines used in the oil and gas sector, as well as securing NOx reductions that will also reduce ozone, visibility, and nitrogen deposition at RMNP.

Except for the combustion process adjustment requirements for engines at major sources, the Commission has not revised the requirements pertaining to engines since 2010, and emissions from engines associated with oil and gas production in Colorado have continued to increase. While the Commission recognizes the twin challenges currently faced by the oil and gas industry in Colorado - the COVID-19 pandemic and low oil prices - this regulation's provisions for phasing in compliance over time and, particularly, the unique characteristics of the Alternative Company-Wide Compliance Plan (Company-Wide Plan, affords the industry the flexibility necessary to achieve emission reductions necessary to protect public health and the environment in a cost effective manner.

Applicability (Section I.D.5.a.)

The Commission adopted a new subpart, Section I.D.5., to establish state-only standards to reduce emissions from a subset of existing stationary engines operating over or equal to 1,000 HP and those placed in service, modified, or relocated after November 14, 2020. As defined in the rule, "placed in service" addresses when an engine is brought to a site for utilization. "Placed in service" is a new term that deviates from the Division and industry's traditional reliance on the defined term "commence construction" or NSPS JJJJ's reliance upon manufacture date.

The Commission is clarifying when replacement of an engine under an authorized alternative operating scenario (AOS) would not trigger the engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. Subsequent replacements under an authorized AOS also would not trigger the replacement engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. If an engine is replaced under an AOS, while it may not trigger the lower standards based on "placed in service," it may nonetheless trigger the lower standards if it is "relocated" – i.e. if the replacement engine is brought into Colorado from outside Colorado, or brought into the nonattainment area from outside the nonattainment area. The return of an engine to the same site from which it was removed for the sole purpose of repair or maintenance is not considered "placed in service" or "relocated" for purposes of this Section I.D.5.

The Commission also adopted a different framework for "relocated" engines in Regulation Number 7, Part E, then in Regulation Number 6, Part B, which provides that engines brought to a site from another location in Colorado are not considered "new" and are not subject to the more stringent standards of the applicable NSPS. Under Regulation Number 7, there are only two exceptions to when an engine is considered new: when an engine is replaced under an alternative operating scenario (AOS) in an existing permit, which requires the engine to meet the same standards as the engine replaced, or when an engine subject to a Company-Wide Plan is moved from one site to another site with the same owner or operator. When an engine is subject to a Company-Wide Plan, the operator will have more flexibility to move an engine as long as it achieves at least the same emission reductions under the plan. However, an engine brought into the 8-Hour Ozone Control Area is considered "relocated" and must meet or exceed the standards as of the date it begins operation, whether or not it is subject to a Company-Wide Plan.

Emission Standards (Section I.D.5.b.)

The Commission adopted different emission standards based on engine configuration and the date that the engine was placed in service, modified, or relocated. The Commission intends that the applicable engine configuration is determined by the most current Division-issued permit or APEN filed prior to November 14, 2020. If the engine configuration is not identified in a Division-issued permit or APEN, the owner or operator is required to submit an APEN with this information to the Division by May 1, 2021. After November 14, 2020, any change to the identified configuration that results in an emissions increase is considered a modification.

The Commission adopted, generally, more stringent NOx standards applicable to engines placed in service, modified, or relocated after November 14, 2020. However, for 2-stroke lean burn engines, the NOx standard is the same whether the engine is currently in use at a site or brought on at a later date. The Commission also intends that any engines subject to a more stringent standard under a permit or other rule, such as Section I.D.2.b. of Regulation Number 7, must still comply with that more stringent limit. The Commission adopted varying timing requirements for owners or operators to meet the emission standards, based on the location of subject engines inside and outside of the 8-Hour Ozone Control Area. Owners or operators with any engines in the 8-Hour Ozone Control Area are subject to a more aggressive timeline, which requires 100% of engines inside the 8-Hour Ozone Control Area to meet the emission standards by May 1, 2024, and 100% of engines outside the 8-Hour Ozone Control Area meet the emission standards by May 1, 2026. Operators with no engines inside the 8-Hour Ozone Control Area must follow the second timeline and meet the standards of at least 20% of engines each year from 2022 to 2026.

The Commission intends that the emission standards in Table 2 are a gram per horsepower-hour limit based on appropriate averaging times. The Commission also intends that operators demonstrate compliance with the certification and recordkeeping requirements through the performance testing results required by Section I.D.5.d and the portable analyzer results obtained in accordance with Section I.D.5.e., using the appropriate averaging times.

The Commission requests that the Division consider evaluating strategies to increase the electrification of engines, lower emissions standards for engines, and possible controls applicable to smaller engines.

Notification to Division (Section I.D.5.b.(iii))

If an owner or operator has subject engines, the owner or operator must submit a notice to the Division no later than May 1, 2021. However, the owner or operator of engines covered by a Company-Wide Plan will not need to submit the information required by Section I.D.5.b.(iii) for all engines.

Permit Modification (Section I.D.5.b.(iv))

The Commission adopted two deadlines for when a permit modification application is required. If the engine can meet the standards through only a permit modification, the application is due May 1, 2021. If the engine cannot meet the standards through only a permit modification, the application is due 365 days prior to that engine's compliance deadline. An example of the first scenario is where an engine currently permitted with a high emission rate can meet the standards if operated at a lower emission rate and it is, in fact, already operating as of November 14, 2020, at that lower emission rate. In contrast, an example of the second scenario is where an engine is permitted at an emission rate above the applicable standard and operates at its permitted level, which would require the operator to change the operation of the engine in order to comply. This engine, therefore, would have a compliance date in accordance with Section I.D.5.b.(v)(B), and the permit application would be due 365 days prior to that engine's compliance deadline. Stakeholders expressed concerns that the Division may not be able to timely process all of the permit modifications. Therefore, the Commission determined that the flexibility outlined in the rule was necessary for both industry and the Division. In the case of a pending permit modification, the Commission intends that the most current APEN requested limits will be used to determine compliance with the rule.

Industry stakeholders have expressed that the rules need to be more accommodating for Division delays in permit issuance for those situations where owners and operators cannot take action to comply with the emission standards without a permit in hand. Industry notes that without a revised permit, owners and operators would be out of compliance with federal and state permit requirements, leaving the operator with the choice of what standards to comply with. Based on information provided by these stakeholders, the Division believes that there are only 15 such permits. Additionally, the vast majority of engine upgrades do not necessitate a permit modification prior to completing the upgrade.

The Division has indicated that it has enough dedicated staff to complete the required permit modifications in a timely fashion so long as the operator submits the permit application at least one year in advance of the compliance deadline. To address stakeholder concerns, the Commission expects the Division to work with operators that require a permit prior to commencing upgrades and create a process to give these permit applications priority. Should any permits push up against the one-year issuance deadline, the Division, in its discretion, will evaluate any potential operator compliance deadline extensions on a case-by-case basis.

Alternative Company-Wide Compliance Plan (Company-Wide Plan) *(Section I.D.5.c)*

The Commission adopted a Company-Wide Plan option to allow flexibility for each owner or operator to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emission reductions than would be achieved through compliance with the emission standards on an individual engine basis.

The Company-Wide Plan requires an overall emissions percentage reduction based on company-wide engine operations. Owners or operators using this option must demonstrate that the total NOx emissions allowed under the Company-Wide Plan are less than or equal to the total NOx emissions allowed through compliance with the emission standards on an individual engine basis. Engines included in a Company-Wide Plan remain subject to the performance testing, monitoring, recordkeeping, and reporting requirements.

This Company-Wide Plan option is available only to owners or operators with five or more engines that are subject to Section I.D.5.b(v)(B). For purpose of the Company-Wide Plan only, the term owner/operator refers to owners or operators that are participating in a Company-Wide Plan and are owned or operated by the same parent company. Engines that already meet the emission standards of Table 2 but only need a permit modification to reflect compliance may not be part of a Company Wide Plan for which credit is claimed by the operator. However, if the operator makes a further retrofit to the engine, the operator may include that engine in the Company Wide Plan and claim credit for the reductions achieved by the further retrofit. For example, if Engine A, a 4-stroke lean burn engine, has a permit limit of 1.8 g/hp-hr, but currently operates at 1.2 g/hp-hr, Engine A would not be included in the Company Wide Plan. However, if the operator installs additional control technology such that Engine A can now operate at 1.0 g/hp-hr, the emission reductions associated with the drop in emissions from 1.2 g/hp-hr to 1.0 g/hp-hr can be included in the Company-Wide Plan. Only physical retrofits, and not operational changes, can be accounted for in this manner.

Owners or operators will submit a notification (referred to as a compliance plan) using a Division-approved form that will be developed with stakeholder input. Recognizing that the Company-Wide Plan is intended to afford flexibility only where it will achieve the same or better reductions, the Commission has provided for detailed information to be submitted to the Division for review. The information submitted will allow the Division to compare the emission standards and operating conditions that an engine is meeting before and after the Company-Wide plan as well as the maximum emissions permissible if all Company-Wide Plan engines complied individually with the standards versus the permissible emissions under the Company-Wide Plan.

Owners or operators must calculate “Plan Emission Reductions” - i.e. a summation of NOx emission reductions from all engines in the Company-Wide Plan. This figure is calculated by looking at the maximum amount of NOx emissions from the engines before November 14, 2020 (using the current permitted emission rate) and subtracting the maximum amount of NOx emissions that will be allowed from those engines under the Company-Wide Plan.

Owners or operators must also demonstrate that the Company-Wide Plan will result in real emission reductions, and the Division is directed to disapprove any Company-Wide Plan that the Division determines does not achieve those reductions. Owners or operators will calculate the estimated historic emissions from the plan's engines in tons per year as a baseline, using the most stringent regulatory or permitted emission standards and operating conditions in conjunction with actual operating hours (averaged over 2017-2019). That baseline figure is then compared to the maximum amount of emissions permissible from the Company-Wide Plan engines to ensure that the Company-Wide Plan will result in emission reductions. The demonstration also includes a comparison of the emission reductions that would be achieved from the actual baseline figure if each engine complied with the emission standards on an individual basis to the reductions that will be achieved under the Company-Wide Plan. In this way, the Commission seeks to ensure that a Company-Wide Plan achieves demonstrable reductions in NOx emissions.

Owners or operators will not be allowed to utilize reductions in permitted operating hours to offset emission reductions that would otherwise be achieved where permitted hours are higher than actual hours of operation (on average over 2017, 2018, and 2019). For example, an operator with a permit to operate at 8,760 hours per year but that operated only at 5,000 hours per year (on average over 2017, 2018, and 2019) cannot modify its permit to lower the permitted hours of operation to 5,000 and thereby create NOx emissions for which it can take credit in its Company-Wide Plan.

Some stakeholders have expressed concerns over how engines that began operation during or after the averaging years will calculate "historic" emissions. For these types of engines, the Commission expects that the most recent year(s) of operation should be used to calculate "historic" emissions. If there is less than one year of operation during this time frame, the Commission expects that the operator should extrapolate the available operation emission data to one year to estimate "historic" emissions.

Owners or operators must also submit notice of relocated engines in the annual update to the Company-Wide Plan, beginning in 2022. A relocated engine will be categorized by its new location (inside or outside of the 8-Hour Ozone Control Area) for purposes of the engine's compliance deadline.

To assist with implementation, the Commission directs the Division to provide timely guidance to the regulated community as to how to develop a Company-Wide Plan. The Commission recognizes that the Company-Wide Plan provisions are complicated, and believes providing the following examples of how the Commission intends the program to work will be helpful.

Example 1:

An engine in a Company-Wide Plan is located inside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), also within the 8-Hour Ozone Control Area. The engine was not "placed in service" or "relocated" within the meaning of this rule, and compliance deadlines would not change. The owner/operator just submits the new location in its annual update.

Example 2:

An engine in a Company-Wide Plan is located outside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), except that site B is located inside the 8-Hour Ozone Control Area. The engine is not "placed in service" within the meaning of this rule but it is "relocated." The engine's relocation into the 8-Hour Ozone Control impacts both the standard with which it must comply and the timing of when the new standard must be achieved.

If the engine was not proposed for retrofit or if it was proposed for retrofit but under the Company-Wide Plan it would not meet the standard, the engine will need to meet the emission standards as of its date of operation following relocation. If the engine was proposed for retrofit to achieve performance below the emission standards (retrofit/shut-down, etc.), the engine must meet the more stringent of either the applicable standard or the proposed Company-Wide Plan standard as of the date of operation following the relocation date.

Conversely, if an engine subject to a Company-Wide Plan located in the 8-Hour Ozone Control Area is moved to a different site (same owner/operator) outside of the 8-Hour Ozone Control Area, the engine is not “placed in service” or “relocated” within the meaning of this rule. The engine must meet the standard specified in the Company-Wide Plan consistent with the applicable compliance date.

Example 3:

Operator A has 20 engines and submits a Company-Wide Plan that includes modifying five engines (in 2022 and 2023) and shutting down two engines (in 2024). Operator A then transfers ownership of one of the engines (either the engine or the entire facility) to be shut down to Operator B; that shutdown would have achieved 20 tons per year (tpy) NOx reduction. Operator A must find an additional 20 tpy NOx reduction from the 19 engines remaining in its Company-Wide Plan.

Example 4:

A Company-Wide Plan includes shutting down an engine. The operator then realizes it needs a replacement engine at that same site. The operator has a few options. First, the operator can amend its Company-Wide Plan to no longer shut down the engine (assuming the engine’s compliance deadline has not yet passed) and can identify other actions to be taken to achieve the emission reductions that would have otherwise been realized from the shutdown of the engine. Second, the operator can shut down the engine as originally intended and bring on a new engine. The new engine will be subject to the emission standards as an engine “placed in service” after November 14, 2020, and cannot be a part of the operator’s Company-Wide Plan because an engine scheduled for shut down under a Company-Wide Plan cannot be replaced with a different engine subject to the Company-Wide Plan. Because the operator must comply with the Company-Wide Plan, the operator will still need to cancel the APEN and permit for the existing engine and permit the new engine as a new source.

Example 5:

An operator has ten engines subject to a Company-Wide Plan and intends to modify five of those engines to achieve the required Plan Emission Reductions. However, in order to meet the CO standards for one of the engines that will not be modified to achieve Plan Emission Reductions, the operator must make an adjustment that has the effect of increasing NOx emissions from that engine. In calculating the maximum allowable NOx emissions from engines in the compliance plan and Plan Emission Reductions required, the operator must account for the increase in NOx emissions from the engine.

Performance Testing, Monitoring, Recordkeeping, and Reporting (Sections I.D.5.d., I.D.5.e., I.D.5.f., and I.D.5.g.)

The Commission adopted performance testing requirements to establish a baseline for evaluating an engine’s performance – i.e. to enable an operator to know whether the engine was meeting the standards already or how much action might be required to meet the standards. To conserve the resources of both the Division and the operators, the Commission has allowed for operators to rely on existing ongoing semi-annual portable analyzer testing requirements, as well as performance testing conducted under NSPS JJJJ, a permit, or testing conducted voluntarily after January 1, 2020.

The Commission also adopted semi-annual portable analyzer testing requirements. The portable analyzer monitoring must commence within twelve (12) months of the initial performance test. The Commission intends that operators will conduct two portable analyzer tests in 2022, the first of which must be completed by June 30, 2022.

The Commission has also adopted new monitoring, recordkeeping and reporting requirements. With respect to oil and filter changes under Section I.D.5.e.(iv)(A), the Commission acknowledges that the development of an oil analysis program that tests to ensure that oil does not need to be changed meets the requirements of that section.

In the recordkeeping section, the Commission requires that for both performance tests and portable analyzer tests, the owner or operator retains records regarding the date, engine settings on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission acknowledges that maintaining the test reports (for performance tests) and maintaining records consistent with the Division’s Portable Analyzer Monitoring Protocol (for portable analyzer test), is sufficient to demonstrate compliance with the requirements to maintain the date, engine setting on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission has required the reporting of the results of performance tests (Section I.D.5.g.(i)) and semi-annual portable tests (Section I.D.5.g.(iv)). By “results,” the Commission means that the owner/operator shall indicate whether the tests were passed or failed. Other, more detailed results are required to be maintained as part of the recordkeeping requirements and will be available to the Division upon request.

General provisions (Section I.D.2.)

In 2019, the Commission adopted a reorganization of Regulation Number 7 moving like-sections together, including engines. The Commission now completes the reorganization of the engine sections by duplicating the applicable general provisions that applied to engines in Part D, Section II. (formerly numbered Section XVII.) in Part E, Section I.D.2. These provisions will continue to apply to engines addressed in Part E, Sections I.D.3. and I.D.4. (formerly Sections XVII.E.) and will also apply to engines addressed under the new Part E, Section I.D.5.

<u>Oil and gas operations (Part D)</u>

The Commission expanded or adopted additional requirements in Part D to further minimize emissions of greenhouse gases, ozone precursors, and other hydrocarbons from the oil and gas sector.

Pre-production and early production monitoring

The Commission adopted a new Section IV. that requires owners or operators to monitor air quality at and/or around pre-production operations (i.e., drilling, fracturing, drill-out, flowback) and early production operations (i.e., six months). The purpose of this air quality monitoring is multi-faceted in that the Commission anticipates the monitoring program will gather information about the evolving oil and gas monitoring technologies, data about potential emissions during pre-production and early production operations (e.g., ozone precursor emissions, greenhouse gas emissions, hazardous air pollutants), and inform future monitoring efforts. Owners or operators will also monitor air quality for ten days prior to beginning pre-production operations. The Commission recognizes that ten days does not provide a comprehensive or long-term baseline but intends that it cover day-of-week variability in surrounding activities and short-term meteorological variability, in order to provide a reference point for interpreting subsequent data.

Owners or operators must submit an air quality monitoring plan to the Division for approval prior to monitoring air quality. The Commission created a flexible air quality monitoring program that allows the operator to specify what pollutant(s) representative of pre-production and early production hydrocarbon emissions will be monitored and by what monitoring technology. The Commission anticipates that the additional elements of the air quality monitoring plan, such as monitor siting, frequency of measurements, monitoring equipment limitations, and ability to trigger or collect speciated samples, will vary based on the monitoring objectives and technology utilized. The Commission also anticipates that the response level(s) will vary based on the monitoring technology, monitor placement, the pollutant(s) monitored, data collection and averaging times, and other factors. The response level may differ from a lower detection level established by the owner or operator that triggers an initial investigation of potential emissions at the facility. The Commission expects that the monitoring technology selected will have a detection ability sufficient to detect the pollutant(s) monitored at an appropriate level above area concentrations such that the monitoring objectives (e.g., detect ozone precursors, detect hazardous air pollutants, detect greenhouse gas emissions, associate elevated monitored values to an emission source within the monitored operations) are achieved. The Commission recognizes that not every elevated measurement constitutes a detection requiring a response but instead may be accompanied by analytics evaluating the measurements in comparison to an emission source or activity. The Commission also expects that placement of the monitors will be designed to be adequate to meet the objectives of the monitoring plan and that operators will select a monitoring technology that collects measurements at short-term intervals (e.g., 1 minute, 15 minutes, 1 hour) and appropriate sensitivity.

For example, concentrations at 2000-4000 feet away from the operations are likely to be low and, therefore, would require high-sensitivity instruments; monitors placed in close distance to the operations may need to be placed at variable heights to detect emissions from equipment of different heights; or monitors may need to be placed in both upwind and downwind locations, depending on the monitoring technology. In addition, the Commission expects the Division to work with operators in approving air quality monitoring plans to make sure that local jurisdiction air quality monitoring requirements and COGCC site preparation requirements are considered. The Commission expects the Division to consult with relevant local governments in reviewing monitoring plans, to obtain their input on local circumstances or concerns that may guide the Division's determinations on plan adequacy.

Owners or operators will also submit monthly reports of air quality monitoring to the Division. These monthly reports will include descriptions of activities that occurred during the monitoring period such that monitoring data can be understood in relation to activity onsite (e.g., accounting for engine emissions). The Commission recognizes that monitoring data often requires additional analysis to interpret the resulting data. Therefore, for this first oil and gas air quality monitoring program, the Commission expects that operators will make the raw data (e.g., monitor/sensor and meteorological readings prior to analysis or processing) available to the Division upon request (and expects the Division to make the raw data available to the relevant local government entities upon request) but submit the analyzed data results in the monthly reports. The Commission believes these reports will provide valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make the reports publicly available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. This flexible monitoring program is intended as an initial step to help inform future oil and gas monitoring efforts.

Recognizing that this pre-production emissions monitoring program represents a first step in understanding both pre-production emissions and the rapidly evolving technologies that may be used to monitor them, the Commission directs the Division to report back to the Commission no later than March 31, 2022 with an initial summary of activities to implement the rule since September, 2020; learnings and insights on monitoring technologies, including technologies for continuous methane monitoring; appropriate data summaries on observed emissions based on the monthly reports received; initial feedback on the adequate length of monitoring time during and possible identification of exemptions from monitoring for certain types of facilities.

Flowback vessels

The Commission also adopted in the new Section VI. a requirement for owners of operators of pre-production operations to control emissions from flowback vessels. After hydraulic fracturing, operators bring the frac fluids and entrained solids to the surface. EPA's NSPS OOOOa Section 60.5375a requires operators to route flowback during the initial flowback stage into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. During the separation flowback stage, NSPS OOOOa requires operators to route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into a well, or route the liquids to a collection system. NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to control well completion vessel emissions. Therefore, to build on the NSPS reduced emission completion requirements and further reduce pre-production tank emissions, owners or operators of pre-production operations must use enclosed flowback vessels after the drill-out phase, which the Commission recognizes has a high ratio of solids to liquids, and route emissions from flowback vessels to air pollution control equipment.

Class II disposal well facilities

The Commission added a new definition of class II disposal well facilities. This definition is based on EPA's Underground Injection Control Program: Criteria and Standard definition of class II well (see 40 CFR Section 146.5(b)(1)). The Commission did not include the element of EPA's definition concerning enhanced recovery of oil or natural gas as storage tanks related to those activities are considered part of the associated well production facility. The Commission recognizes that some class II disposal well facility operators interpret Part D, Section II.C. such that their storage tanks have not been subject to the storage tank control requirements. Although the Commission understands that the Division intended Part D, Section II.C. to apply to storage tanks serving class II disposal well facilities, the Commission also recognizes that a good faith argument existed under the prior rule language to support the alternative interpretation. The Commission intends for the Division to work with owners or operators to address implementation concerns that may arise including related to the May 1, 2021, state-wide compliance deadline for controlling emissions from storage tanks $\geq$ 2 tpy and associated monitoring requirements as well as concerns related to the need for supplemental fuel to control emissions.

The Commission also expanded the hydrocarbon liquids loadout requirements in Part D, Section II.5. to hydrocarbon liquids loadout at class II disposal well facilities. Operators inject fluids, primarily brines, associated with oil and natural gas production into class II wells. Current regulatory requirements in the Safe Drinking Water Act for class II wells relate to the construction, operation, and monitoring of the well. The Safe Drinking Water Act does not require emissions reporting or storage tank or loadout emissions controls at class II disposal well facilities. Therefore, the Commission expanded the hydrocarbon liquids loadout requirements to class II disposal well facilities to reduce emissions from these operations.

The Commission directs the division to evaluate potential emission issues associated with load ins at class II disposal facilities

Annual emissions reporting

In 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, CO, ethane, and methane emissions to the Division on an annual basis. To further address and inform the GHG directives of Senate Bill 19-096 and House Bill 19-1261, the Commission expanded the reporting requirements to include the reporting of CO2 and N2O emissions from Colorado's oil and gas sector.

As described above, the Safe Drinking Water Act does not require emissions reporting. Therefore, the Commission also clarified and expanded the annual emissions reporting requirements for class II disposal well facilities to better understand the emissions from these facilities and activities. Related to the fluids accepted for injection disposal, the Commission is requiring owners or operators to take periodic samples of the liquids to inform emission estimates. Acknowledging that fluid intake and facility designs may differ, the Commission expects the Division will work with owners and operators to develop sampling frequencies and protocols and to ensure accurate and consistent methods are used for emissions estimation and reporting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission includes reference dates to rules and reference methods incorporated in Regulation Number 7.

Community Engagement

Section 25-7-105(e) requires engagement with disproportionately impacted communities, other state agencies, stakeholders, and the public. The Division provided multiple ways for the public, local governments, industry, environmental groups, and other stakeholders to provide comment during the development of the proposed rules, including email and remote stakeholder meeting participation.

Additional Considerations

The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and Regional Haze Rule and requires Colorado to attain the NAAQS and reduce visibility. Therefore, the Commission adopted certain revisions to Regulation Number 7 to reduce VOC and NOx emissions in Colorado.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including engines, pre-production operations, and class II disposal well facilities storage tanks and storage tank loadout. The proposed revisions also revise the annual oil and gas sector emissions inventory report to include GHGs and class II disposal well facilities. NSPS JJJJ, NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, NESHAP ZZZZ, and the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR Part 98 may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks then the NSPS and NESHAP, more engines than NESHAP JJJJ, and more facilities and operations than the GHGRP.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. The Regional Haze Rule was also not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. And, Colorado must improve visibility in accordance with Regional Haze. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits. And, the current revisions will improve visibility across the state, in particular in Colorado's class I areas.

(V) Colorado must attain the 2008 ozone NAAQS by July 20, 2021, and the 2015 ozone NAAQS by August 3, 3021, or risk being reclassified. Colorado must make reasonable progress toward improving visibility or risk EPA establishing a federal regional haze plan for Colorado. EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. EPA has established a Regional Haze SIP submittal deadline of July 1, 2021. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 address emissions from engines and the oil and gas sector in a cost-effective manner, as detailed in the Economic Impact Analysis, allowing for continued growth of Colorado's industry.

(VII) The revisions to Regulation Number 7 establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado continues to fail to achieve the NAAQS or make progress to reduce visibility, EPA may promulgate Federal Implementation Plans; thus potentially determining requirements for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing and revising annual oil and gas inventory reporting are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for hydrocarbon liquid loadout. Other revisions reflect changes in industry practice, such as for controlling emissions from flowback vessels.

(XI) The revisions adopted will reduce NOx, VOC, and methane, addressing both Colorado's ozone problems, making strides to reduce the impact of climate change, and making progress to improve visibility. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in greenhouse gases, ozone, VOC, NOx, other hydrocarbons, impacts to visibility, and nitrogen deposition to address Regional Haze, SB 19-181, and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements for the oil and gas sector. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in the need for much more stringent requirements to reduce nitrogen deposition in RMNP, improve visibility in Colorado's Class I areas, and reduce ozone across the state but particularly in the DMNFR.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

To the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

U. December 17-18, 2020 (Part D, Section II.; Part E, Sections II., IV., and V.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

On December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

Therefore, to ensure progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to include reasonably available control requirements (RACT) for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy; specifically, for foam manufacturing, boilers, turbines, landfill gas and biogas fired engines, and wood surface coating.

Statutory Authority

The State Air Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources ($\geq$ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, and including categorical RACT requirements.

The Commission is also clarifying requirements related to leak detection and repair (LDAR) inspections. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Major source RACT

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the Clean Air Act's (CAA) Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx including a NOx emission limit for boilers between 50 MMBtu/hr and 100 MMBtu/hr, a NOx emission limit for landfill gas or biogas fired engines, NOx emission limits for combustion turbines, categorical requirements to reduce VOC emissions related to foam manufacturing, and expanded categorical requirements to reduce VOC emissions related to wood surface coating.

Boilers

In 2019, the Commission expanded the combustion equipment requirements adopted in 2016 and 2018 for the 100 tpy major sources to the 50 tpy major sources. Specifically, for boilers, the Commission adopted provisions requiring boilers greater than or equal to 50 MMBtu/hr at 50 tpy major sources to comply with a 0.2 lb/MMBtu NOx emission limit. The Commission now further expands the categorical RACT requirements to require 50-100 MMBtu/hr boilers at 50 tpy major sources to comply with a 0.1 lb/MMBtu NOx emission limits. The owners or operators of these boilers will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Engines

In 2019, the Commission expanded the NOx emission limit requirements for compression ignition reciprocating internal combustion engines (RICE) and combustion process adjustment requirements for stationary RICE. The Commission now further expands the categorical RACT requirements for engines to include landfill gas and biogas fired RICE and require the engines to comply with the NOx emission limit in EPA's NSPS JJJJ for landfill/digester gas fired engines. The owners or operators of these engines will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Turbines

In 2019, the Commission adopted provisions requiring turbines constructed before February 18, 2005, to comply with NSPS GG and turbines construction after February 18, 2005, to comply with NSPS KKKK. During review of the submitted SIP RACT requirements, EPA questioned Colorado's reliance on EPA's NSPS GG as RACT and requested Colorado consider the NOx emission limits in EPA's NSPS KKKK for Colorado's NSPS GG and pre-NSPS GG turbines at major sources. While the Commission does not agree that NSPS GG is inappropriate as SIP RACT for Colorado's NSPS GG and pre-NSPS GG turbines, the Commission revised the requirements for turbines to reference NSPS KKKK NOx emission limits for the turbines constructed before February 18, 2005, but retain the testing and monitoring requirements of NSPS GG. Turbines with CEMS that are capable of operating in both combined and simple cycle modes are to show compliance with a 30-day average. Similar to EPA's discussion in the preamble to NSPS KKKK, the Commission recognizes turbines may have emission spikes during unit startup and that, therefore intends the turbine NOx emission limits to be implemented as under NSPS KKKK. See 71 Fed. Reg. 38,482 at 38,488-38,489 (July 6, 2006) "While continuous compliance is not required, excess emissions during startup, shutdown, and malfunction must be reported." All turbines will continue to comply with good air practices for minimizing emissions, combustion process adjustment, and recordkeeping requirements.

Wood coating

In 2018, the Commission adopted requirements for wood furniture surface coating based on recommendations in EPA's Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations CTG (Wood Furniture CTG) (1996), including topcoat and sealer VOC content limits, work practices, and recordkeeping requirements. Wood furniture is defined to mean "any product made of wood, a wood product such as rattan or wicker, or an engineered wood product such as particleboard," which is not inclusive of all wood products such as doors. However, in EPA's A Guide to the Wood Furniture CTG and NESHAP (1997), EPA states that "States may choose to extend their rules to other operations. For example, some States have developed rules for manufacturers of wood products so they may include limitations for manufacturers of items such as musical instruments or doors." Therefore, the Commission expanded the wood furniture surface coating requirements to the surface coating of other wood products such as doors, door casings, and decorative wood accents.

Foam manufacturing

The Commission adopted new VOC control requirements for foam manufacturing operations. The new provisions affect three foam manufacturing operations, although one of the sources is modifying their permit to more accurately reflect their actual emissions and will, therefore, have VOC emissions below 50 tpy. These new provisions include emission control requirements, work practices, monitoring, and recordkeeping requirements for foam manufacturing operations.

LDAR (Part D, Section II.)

The Commission also adopted clarifying revisions to the leak detection and repair (LDAR) provisions the Commission adopted in December 2019 including clarification to applicability and requirements for recordkeeping and reporting. The clarifications to Sections II.E.4.c. and II.E.4.d. ensure that operators continue to determine applicability in accordance with the storage tank or facility emissions as they have since the LDAR program was adopted in 2014. The inclusion of recordkeeping and reporting elements specific to increased inspections based on location from occupied areas ensure that the Commission can evaluate the efficacy of the LDAR program. The Commission acknowledges that not all operators will need to conduct a precise analysis concerning their location in relation to occupied areas (i.e., proximity analysis) based on their general distance. However, the Commission believes it is important for operators to provide at least general documentation that they considered their location, even if to describe an extreme remote location. The Commission also acknowledges that some operators may elect to comply with the increased frequency inspections for certain facilities without conducting a proximity analysis. Documentation of this decision to comply with the increased inspection frequency satisfies the proximity analysis requirement.

The Local Community Organizations proposed an alternate rule to establish shorter repair deadlines for leaks discovered at well production facilities within 1,000 feet of an occupied area. The Local Community Organizations, industry, and the Division negotiated and agreed to the final language adopted by the Commission. For leaks identified at a well production facility located within 1,000 feet of an occupied area, operators must make a first attempt to repair the leak as soon as practicable, but no later than five working days after discovery of the leak. If repair cannot be completed within five days and the leak is not stopped using other means, the owner or operator must notify the local government with jurisdiction over the location and the Division. Reasons why an operator may be unable to attempt or complete repair within five days include, among other things, inclement weather that prevents a timely repair or repair attempt or delays in procuring necessary heavy equipment and workover rigs. The industry parties also raised the issue about local government or other agency requirements potentially delaying repair. Such impacts to repair schedules should be considered as the program is implemented.

The Commission notes that it will be the operator's responsibility to demonstrate the need for the delay beyond five working days, and the Commission expects that operators will be able to explain the types of reasonable efforts the operator undertakes to avoid the delay (e.g., reasonable efforts in procuring the equipment). If a leak is detected at a facility without a proximity analysis, operators may conduct a proximity analysis and may follow the repair deadlines in Section II.E.7.a. if there are no occupied areas within 1,000 feet.

Consistent with the existing LDAR program, leaks detected are not subject to enforcement by the Division so long as the operator complies with the repair and recordkeeping requirements of Section II.E. However, as the Commission noted in 2014 and again in 2017, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Part D, Sections I.C, II.B, or II.C (as applicable), including the requirements to minimize emissions and to operate without venting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado’s ozone SIP to address the serious ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado’s serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado’s SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), CRS, the Commission determines

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including fugitive emissions from components. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more fugitive emissions components then the NSPS.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx ($\geq$ 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part B, Section I. and Part E, Sections II. and V. to include categorical regulatory RACT requirements. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 2008 NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 strengthen Colorado's SIP and state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections I. recognize practices currently utilized by wood coating operations. The revisions to Regulation Number 7, Part E, also consider specific existing major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C and Part E similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for component leaks. Other revisions reflect changes in industry practice, such as for wood coating and foam manufacturing. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

V. February 18, 2021 (Part D, Section III.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for the Commission. SB 19-181 revised the Air Quality Control Commission's directives in § 25-7-109, CRS, to consider pneumatic device requirements. Additionally, in HB 19-1261, the legislature mandated a 26% reduction in GHG by 2025, 50% by 2030, and 90% by 2050 (from a 2005 baseline), §§ 25-7-102(2)(g), 25-7-105(1)(e)(II), CRS.

Further, on December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

Therefore, to further minimize emissions from the oil and gas sector and ensure progress towards attainment of the 2008 and 2015 ozone NAAQS and necessary greenhouse gas emission reductions, the Commission is adopting revisions to Regulation Number 7 to require non-emitting controllers in certain situations.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution.

Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7- 109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7 and includes the technological and scientific rationale for the adoption of the revisions. The revisions also correct typographical, grammatical, and formatting errors found through the regulation. As discussed, SB 19-181 identifies specific requirements the Air Quality Control Commission should consider, including pneumatic controller requirements.

In December 2019, the Commission expanded the pneumatic controller inspection and maintenance requirements, adopted in 2017, from nonattainment area applicability to statewide applicability. As part of that rulemaking, the Commission directed the Statewide Hydrocarbon Emission Reduction (SHER) team and Pneumatic Controller Task Force (PCTF), stakeholder processes directed by the Commission in 2017, to continue their stakeholder processes and bring to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Both the SHER team and PCTF continued to meet through the spring of 2020. The stakeholder discussions from 2017-2020 informed the Commission's adopted provisions regarding non-emitting controllers. Non-emitting controllers are a broader category than no-bleed pneumatic controllers and can include, but are not limited to, air-driven controllers, mechanical controllers, electric controllers, self-contained controllers and controllers where exhaust gas is routed to a combustion device.

Definitions

The Commission took the opportunity to amend the definitions associated with pneumatic controllers to reflect more accurate and appropriate technical definitions. The definition of "intermittent pneumatic controller" is intended to include controllers that are not designed to have a continuous bleed rate. Although intermittent pneumatic controllers are not designed to emit between actuations, de minimis emissions may occur between actuations. Such de minimis emissions do not alter a controller's classification as "intermittent."

New Facilities and Certain Retrofits

The revisions to Regulation Number 7 adopted in this rulemaking require the use of non-emitting controllers at well production facilities and natural gas compressor stations that commence operations on or after May 1, 2021. The revisions also require retrofits of natural gas emitting pneumatic controllers to non-emitting controllers at well production facilities where a well first begins production or is recompleted or refractured on or after May 1, 2021 and at natural gas compressor stations that increase horsepower on or after May 1, 2021.

Company-wide plans

Additionally, the Commission has required operators with well production facilities or natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert some of such facilities to use non-emitting controllers. For purposes of Section III.C.4, retrofit refers to converting a natural gas emitting pneumatic controller to a non-emitting controller. Plugging and abandoning an existing well production facility constitutes an alternative method of compliance with retrofit requirements as described in Section III.C.4.c.(iii). Specifically, the Commission has adopted a program that requires owners or operators of well production facilities that commenced operations prior to May 1, 2021 to determine the percentage of their total liquids production at facilities with non-emitting controllers. Facilities that commenced operation prior to May 1, 2021 shall be included in the relevant (well production or compressor station) companywide plan, and the companywide plan shall reflect operations as of May 1, 2021. If any of the events described in Sections III.C.4.a.(ii) or (iii) occur on or after May 1, 2021 and before May 1, 2023, then the owner or operator may count, as applicable, the: (1) percentage of production allocated to that facility as of May 1, 2021 as retrofit for purposes of the well production facility companywide plan; or (2) the pneumatic controllers emitting to atmosphere as of May 1, 2021 as retrofit for purposes of the compressor station companywide plan. Where facility production must be estimated pursuant to Section III.C.4.c.(ii)(A)(3), owners or operators will follow the same process that would be used to establish permit limitations on production throughput, such as summation of anticipated production curves. Of note, if a facility operating in 2019 was subsequently acquired by a new operator, then the facility (and its percent of production) is associated with the company-wide plan of the entity owning the facility as of May 1, 2021.

Based upon this percentage, operators will be required to retrofit facilities incrementally by May 1, 2022 and May 1 2023; the required retrofits correspond to an increasing percentage of each operator's total liquids production flowing through facilities with non-emitting controllers. The incremental percentage increases for well production facilities are found in Table 1. Operators that increase their total non-emitting facility percent production up to a specified threshold are not required to achieve the entire incremental percentage increase that would otherwise apply for that year. However, the minimum incremental increases and specified thresholds do not restrict operators from exceeding the requirements.

Each well production facility operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, its total liquids production, facilities with non-emitting controllers, total percentage of liquid production flowing through facilities with non-emitting controllers, and the facilities that the operator intends to retrofit or plug and abandon in order to achieve the incremental increases in total liquids production flowing through facilities with non-emitting controllers. This company-wide plan should be updated in July 2022, with a final company- wide plan reflecting all facilities that were retrofit or plugged and abandoned submitted in July 2023.

The Commission has also required operators of natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert pneumatic controllers at such facilities to non-emitting controllers. Specifically, the Commission has adopted a program that requires operators to determine the percentage of emitting and non-emitting pneumatic controllers and based upon that percentage, operators will be required to increase the percentage of non-emitting controllers incrementally by May 1, 2022 and May 1, 2023. The incremental percentage requirements for natural gas compressor stations are found in Table 2. As for well production facilities, operators that increase their total percentage of non-emitting controllers up to a specified threshold are not required to achieve the entire percentage increase for that year that would otherwise apply. The minimum percentage increases and specified thresholds do not restrict operators from exceeding these requirements.

Each operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, total controllers, percentage of emitting and non-emitting controllers, the required incremental increases in non-emitting controllers, and the pneumatic controllers that the operator intends to retrofit or remove from service to achieve the incremental increases in non-emitting controllers.

For well production facilities and natural gas compressor stations, an owner or operator may elect to combine facilities with other owners or operators that are owned or operated by the same parent company in complying with company-wide compliance plan requirements.

At this time, operators will not be subject to the requirement to retrofit pneumatic controllers if they have facilities that on a company-wide basis, and taking into account only wells that produced oil or gas or both in calendar year 2019, averaged 15 barrels of oil and gas equivalent (“BOE”) or less per day per well. However, in 2021, the Commission plans to consider additional emission reductions for the oil and gas sector that would enable the state to meet its ambitious climate goals as set forth in HB 19-1261. The Commission directs the Division to consider whether additional requirements to reduce emissions at the sites not subject to retrofit pursuant to Section III.C.4.c.(iv), including retrofit of pneumatic controllers, should be included in that rulemaking.

The requirement to submit an acknowledgement or certification under Sections III.C.4.c.(v) and III.C.4.d.(v) (regarding sale or transfer) does not apply to well production facilities or natural gas compressor stations that, at the time of sale or transfer are not intended to and will not be used to achieve the Total Required Non-Emitting Facility Percent Production or Total Required Non-Emitting Percent Controller target, as applicable. The following are each an acceptable means of ensuring compliance with Section III. following transfer through which owners or operators shall satisfy their obligations under Section III.C.4.c.(v) or Section III.C.4.d.(v), as applicable:

Example 1: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61%. Operator A is required to achieve an additional 5% of non-emitting facility percent production by May 1, 2022, and an additional 10% by May 1, 2023, with a Total Required Non-Emitting Facility Percent Production target of 76%. Operator A achieves the additional 5% of non-emitting facility percent production by May 1, 2022. In 2023, prior to May 1, Operator A transfer's ownership to Operator B of two well production facilities that Operator A had intended to retrofit with non-emitting controllers or plug and abandon in order to achieve its Total Required Non-Emitting Facility Percent Production. Retrofitting or plugging and abandoning those two facilities would have comprised half of the additional production required by May 1, 2023 (*i.e.*, 5% of Total Required Non-Emitting Facility Percent Production).

Scenario 1: Notwithstanding the transfer, Operator A may find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non-Emitting Facility Percent Production. In this case, Operator A does not need to submit an acknowledgement or certification upon transfer, but shall include this information in its next update to the Company-Wide Plan. This example would apply equally to transfers of assets subject to a Company-Wide Compressor Station Pneumatic Controller Compliance Plan.

Scenario 2: Operator A submits an acknowledgement, on a Division-approved form, that it will ensure the transferred asset is retrofit by May 1, 2023. Under this scenario, either Operator A or Operator B may undertake any necessary retrofitting (or plugging and abandonment) of the asset to allow Operator A to take credit for retrofit of the 5% of Total Historic Production, provided, however, that Operator A will remain responsible for retrofit of that asset to achieve its Total Required Non-Emitting Facility Percent Production. This means that if retrofit of the asset is not completed for whatever reason, Operator A would have to find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non- Emitting Facility Percent Production by May 1, 2023.

Scenario 3: Operator A submits an acknowledgement, on a Division-approved form, that it plans to use the transferred asset to achieve its Total Required Non-Emitting Facility Percent Production and Operator B certifies, on a Division-approved form, that it will retrofit the transferred asset by May 1, 2023. Upon certification by Operator B, Operator A shall receive credit for the retrofit of the 5% of Total Historic Production towards its applicable targets under Section III.C.4. The Division-approved form must include a statement that Operator B assumes Operator A's Section III.C.4 obligations with respect to the transferred asset and is, therefore, subject to the Division's enforcement authority in the event of noncompliance. Acquisition of the asset does not alter the calculation of Operator B's compliance with the percentage thresholds specified in Table 1 or 2 for its own Company-Wide Plan, if applicable.

Example 2: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61% and a Total Required Non-Emitting Facility Percent Production target of 76%. Operator B has a Total Historic Non-Emitting Facility Percent of 21% and a Total Required Non-Emitting Facility Percent Production target of 56%. Operator A and Operator B merge (or one entity acquires the other) in 2023, prior to May 1. Despite the merger, the resulting ownership of Operators A and B must continue to separately comply with the respective Company-Wide Plans and Total Required Non-Emitting Facility Percent Production targets of Operator A and Operator B that existed prior to merger.

Exemptions for Specific Controllers

The Commission has recognized that there are appropriate circumstances where even non-emitting facilities may need to use pneumatic controllers that emit natural gas to the atmosphere.

Section III.C.4.e.(i)(A) authorizes use of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas. Starting May 1, 2021, new well production facilities or facilities where a well first begins production or is recompleted or refractured, and new compressor stations or stations that increase horsepower, must submit a justification for any safety or process exemption to the Division for approval 45 days prior to installation of the emitting device or retrofit of the facility. Owners or operators that intend to rely on this exemption to maintain emitting controllers at facilities that are retrofit under a company-wide plan must submit a justification to the Division 45 days prior to retrofit of the facility. The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities and natural gas compressor stations commencing operation or taking actions described in Sections III.C.4.a.(ii) or (iii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(A)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Sections III.C.4.a.(ii) or (iii) occur. Section III.C.4.e.(i)(A), the requirement to seek Division approval is not applicable for: (1) well production facilities that qualify as contributing to Historic Non-Emitting Facility Percent Production, as defined in Section III.C.4.c.(ii)(D)(1) to (2), or (2) compressor stations that commenced operation before May 1, 2021.

Section III.C.4.e.(i)(B) authorizes use of pneumatic controllers that emit natural gas for activities that occur prior to the end of flowback and well abandonment activities. In addition, Section III.C.4.e.(i)(C) allows owners or operators, upon notice to the Division, to use temporary and portable equipment with pneumatic controllers that emit natural gas for sixty days for purposes other than increasing the throughput of the facility. The Commission directs the Division to develop a streamlined mechanism for filing these notifications, including evaluating the potential for electronic notification. Owners or operators must request Division approval to extend the sixty-day timeframe and must do so at least fourteen days prior to the end of the exemption period. Owners or operators utilizing temporary or portable equipment with pneumatic controllers that emit natural gas must conduct AVO and AIMM inspections of those controllers on the same schedule as the associated well production facility or compressor station under Section II.E., and must comply with the repair, recordkeeping, and reporting requirements of Sections II.E.6 through 9.

The requirement to use non-emitting pneumatic controllers at sites that commenced operations on or after May 1, 2021, or where one or more wells first begin production or are recompleted or refractured on or after May 1, 2021 does not apply in certain applications at some wellheads located away from the associated production facilities. Additionally, operators that have or retrofit well production facilities to be non-emitting pursuant to the company-wide plan may not be required to use non-emitting controllers in certain applications at some wellheads located away from the associated production facilities.

As set forth in Section III.C.4.e.(i)(D), operators may use natural gas actuated pneumatic controllers that emit to the atmosphere to control emergency shutdown devices or artificial lift control at a wellhead if the wellhead is located more than one quarter of a mile from the associated well production facility for well production facilities commencing operations on or after May 1, 2021, or for wellheads not located on the same surface disturbance for well production facilities commencing operations prior to May 1, 2021. Any other pneumatic controllers (e.g. those not used as emergency shutdown devices or for artificial lift control) located at the wellheads within the specified distance from the associated production facilities must be non-emitting, unless the operator submits a justification for use of an emitting controller to the Division for approval at least 45 days prior to installation of the emitting device or retrofit of the facility or by July 1, 2021 for well production facilities that commenced operations prior to May 1, 2021 and the operator intends to be reflected as non-emitting in the company-wide plan. The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities commencing operation or taking actions described in Section III.C.4.a.(ii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(D)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Section III.C.4.a.(ii) occur. The one quarter mile measurement associated with distance from the wellhead to the well production facility shall be measured from the wellhead to the closest equipment associated with the well production facility.

To qualify for the exemption in Section III.C.4.e.(i)(D), the operator must use an approved instrument monitoring method and AVO to detect leaks at the wellhead at the same frequency as the associated well production facility as set forth in Table 3 of Section II.E.4, which sets forth the frequency of component inspections, or no less than once per year, whichever is greater. For facilities that commenced operations prior to May 1, 2021, this monitoring requirement will begin on May 1, 2022, or the date the facility is converted to a site with only non-emitting controllers, whichever is later. The Commission recognizes that wellheads may sometimes be difficult to inspect due to land access issues or severe weather and has adopted provisions allowing operators to delay inspections until access is restored. Owners or operators also may utilize OGI camera-equipped aerial drones to perform these wellhead inspections to provide frequent leak detection and further promote the advancement of leak detection methodologies - both of which are foundational to Colorado's find and fix approach to leak detection. At the same time, the Commission believes this application of OGI requires rethinking of the methodology generally used for land based OGI applications.

Thus, the provisions of Section III.C.4.e.(i)(D)(3) allowing for the use of OGI camera-equipped aerial drones to inspect wellhead equipment apply on a limited basis, as state-only provisions and do not by themselves authorize the use of drones to inspect other equipment or constitute approval of drones as alternative AIMM. Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request. The methodology must include, at a minimum, procedures for: determining maximum wind speed during which the inspection can be performed; determining the maximum viewing distance from the equipment; how the operator will ensure an adequate thermal background is present to view potential leaks; how the operator will deal with adverse monitoring conditions, such as wind; and how the operator will deal with interferences. At a minimum, any drone inspection must ensure line of sight from the drone to all wellhead equipment and components and take place when the drone-mounted camera is close enough to the wellhead equipment and components to achieve sensitivity for detection of emissions similar to the sensitivity commonly achieved during OGI inspections carried out with hand-carried infrared cameras. Furthermore, the Commission directs the parties to this rulemaking that wish to participate to jointly recommend an OGI camera-equipped aerial drone usage methodology to the Division's Alternative AIMM Team by May 2022, for further review and consideration.

Finally, operators may not use this exemption where equipment with natural gas emitting pneumatic controllers other than the wellhead, such as a separator, is located at the wellhead site. Under those circumstances, emitting pneumatic controllers used for emergency shut down control may still qualify for the safety and process exemption under Section III.C.4.e.(i)(A) where the necessary conditions and approvals for that exemption are met.

Tagging of Controllers

In order to assist in ease of identification of pneumatic controllers that are authorized to emit natural gas to the atmosphere, the Commission has required operators to tag pneumatic controllers that are authorized to emit natural gas to the atmosphere pursuant to the specified exemptions in Section III.C.4.e.(i) at wellhead production facilities which are non-emitting and at natural gas compressor stations that have one or more non-emitting controllers. Natural gas compressor station operators must differentiate between emitting pneumatic controllers that are exempt under Section III.C.4.e.(i) and those that are not identified as non-emitting controllers in the company-wide plan and are, thus, not required to retrofit. The requirement to tag pneumatic controllers that emit natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) does not apply at well production facilities that are not required to be non-emitting or elected to be non-emitting pursuant to the company-wide plan requirements. In each instance where the regulation references a requirement to use non-emitting controllers, such reference is limited by the exemptions allowing the use of pneumatic controllers to emit natural gas to atmosphere as set forth in the regulation.

Recordkeeping

Operators of well production facilities or natural gas compressor stations must keep the following records for five years, and make them available to the Division upon request: (1) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date the natural gas compressor station pneumatic controllers were retrofit or it is taken out of service, (2) If claiming an exemption for an emitting pneumatic controller, records for each controller demonstrating the exemption applies, (3) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans, (4) For any operator utilizing III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies under that provision, and (5) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time, other than those revising definitions currently in the SIP.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7- 110.5(5)(b), CRS, the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including natural gas-driven pneumatic controllers. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more natural gas-driven pneumatic controllers than the NSPS.

(II) The Federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations.

(III) The revisions to Regulation Number 7 strengthen Colorado's state-only provisions. These revisions currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(IV) The revisions to Regulation Number 7, Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(V) Where necessary, the revisions to Regulation Number 7 include monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(VI) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for pneumatic controllers.

(VII) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(VIII) Alternative rules could also provide reductions in ozone, VOC, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19- 181 specifically directs the Commission to “consider” revising its rules to adopt more stringent requirements related to pneumatic devices. The Commission determined that the alternate proposal was reasonable and cost-effective.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

To the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record support the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of the regulation in the most cost-effective manner.

R307. Environmental Quality, Air Quality.
R307-501. Oil and Gas Industry: General Provisions.
R307-501-1. Purpose.

R307-501 establishes general requirements for prevention of emissions and use of good air pollution control practices for all oil and natural gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

R307-501-2. Definitions.

(1) The definitions in 40 CFR 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210 apply to R307-501.

(2) "Well production facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for production, extraction, recovery, lifting, stabilization, storage, separation, treating, dehydration, combustion, compression, pumping, metering, monitoring, and flowline.

(3) "Oil well" means an onshore well drilled principally for the production of crude oil.

(4) "Oil transmission" means the pipelines used for the long distance transport of crude oil, condensate, or intermediate hydrocarbon liquids (excluding processing). Specific equipment used in transmission includes, but is not limited to, the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, pumps and compressors, and their driving units and appurtenances. The transportation of oil or natural gas to end users is not included in the definition of "transmission".

R307-501-3. Applicability.

(1) R307-501 applies to all oil and natural gas exploration, production, and transmission operations; well production facilities; natural gas compressor stations; and natural gas processing plants in Utah.

(2) R307-501 does not apply to oil refineries.

R307-501-4. General Provisions.

(1) General requirements for prevention of emissions and use of good air pollution control practices.

(a) All crude oil, condensate, and intermediate hydrocarbon liquids collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the extent reasonably practicable.

(b) At all times, including periods of start-up, shutdown, and malfunction, the installation and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions.

(c) Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the director, which may include, but is not limited to, monitoring results, infrared camera images, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(2) General requirements for air pollution control equipment.

(a) All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable and consistent with technological limitations and good engineering and maintenance practices.

(b) The owner or operator shall keep manufacturer specifications or equivalent on file.

(c) In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates established in rules or in approval orders issued under R307-401 and to handle reasonably foreseeable fluctuations in emissions of VOCs during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: December 1, 2014
Notice of Continuation: September 5, 2019
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-502. Oil and Gas Industry: Pneumatic Controllers.
R307-502-1. Purpose.

(1) The purpose of R307-502 is to reduce emissions of volatile organic compounds from pneumatic controllers that are associated with oil and gas operations.

(2) The rule requires existing pneumatic controllers to meet the standards established for new controllers in 40 CFR Part 60, Subpart OOOO.

R307-502-2. Definitions.

(1) The definitions in 40 CFR 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210 apply to R307-502.

(2) "Existing pneumatic controller" means a pneumatic controller affected facility as described in 40 CFR 60.5365(d)(1) through (3) that was constructed, modified, or reconstructed prior to October 15, 2013.

R307-502-3. Applicability.

R307-502 applies to the owner or operator of any existing pneumatic controller in Utah.

R307-502-4. Retrofit Requirements.

(1) Effective December 1, 2015, all existing pneumatic controllers in Duchesne County or Uintah County shall meet the standards established for pneumatic controller affected facilities that are constructed, modified or reconstructed on or after October 15, 2013, as specified in 40 CFR 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) Effective April 1, 2017 all existing pneumatic controllers in Utah shall meet the standards established for pneumatic controller affected facilities that are constructed, modified or reconstructed on or after October 15, 2013 as specified in 40 CFR 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

R307-502-5. Documentation Required.

(1) The tagging requirements in 40 CFR 60.5390(b)(2) and 40 CFR 60.5390(c)(2), incorporated by reference in R307-210, are modified to not require the month and year of installation, reconstruction or modification for existing pneumatic controllers.

(2) The recordkeeping requirements in 40 CFR 60.5420(c)(4)(i), incorporated by reference in R307-210, are modified to not

require records of the date of installation or manufacturer specifications for existing pneumatic controllers.

KEY: air pollution, oil, gas, pneumatic controllers
Date of Enactment or Last Substantive Amendment: December 1, 2014
Notice of Continuation: September 5, 2019
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-503. Oil and Gas Industry: Flares.
R307-503-1. Purpose.

R307-503 establishes conditions to ensure that flares used in the oil and gas industry are operated effectively.

R307-503-2. Definitions.

(1) "Auto igniter" means a device which will automatically attempt to relight the pilot flame of a flare in order to combust volatile organic compound emissions.

(2) "Enclosed flare" means a flare that has an enclosed flame.

(3) "Flare" means a thermal oxidation system designed to combust hydrocarbons in the presence of a flame.

(4) "Open flare" means a flare that has an open (without enclosure) flame.

R307-503-3. Applicability.

(1) R307-503 applies to all oil and gas exploration and production operations, well sites, natural gas compressor stations, and natural gas processing plants in Utah.

(2) R307-503 does not apply to oil refineries.

R307-503-4. Auto-Igniters.

(1) Flares used to control emissions of volatile organic compounds shall be equipped with and operate an auto-igniter as follows:

(a) All open flares and all enclosed flares installed on or after January 1, 2015, shall be equipped with an operational auto-igniter upon installation of the flare.

(b) All enclosed flares installed before January 1, 2015 in Duchesne County or Uintah County shall be equipped with an operational auto-igniter by December 1, 2015, or after the next flare planned shutdown, whichever comes first.

(c) All enclosed flares installed before January 1, 2015 in all other areas of Utah shall be equipped with an operational auto-igniter by April 1, 2017, or after the next flare planned shutdown, whichever comes first.

R307-503-5. Recordkeeping.

The owner or operator shall maintain records demonstrating the date of installation and manufacturer specifications for each auto-igniter required under R307-503-4.

KEY: air pollution, oil, gas, flares
Date of Enactment or Last Substantive Amendment: December 1, 2014
Notice of Continuation: September 5, 2019

Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-504. Oil and Gas Industry: Tank Truck Loading.
R307-504-1. Purpose.

R307-504 establishes control requirements for the loading of liquids containing volatile organic compounds (VOCs) at oil or gas well sites.

R307-504-2. Definitions.

The definitions in 40 CFR 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, incorporated by reference in R307-210, apply to R307-504.

"Bottom Filling" means the filling of a tank through an inlet at or near the bottom of the tank designed to have the opening covered by the liquid after the pipe normally used to withdraw liquid can no longer withdraw any liquid.

"Submerged Fill Pipe" means any fill pipe with a discharge opening which is entirely submerged when the liquid level is six inches above the bottom of the tank and the pipe normally used to withdraw liquid from the tank can no longer withdraw any liquid.

"Vapor Capture Line" means a connection hose, fitted with a valve that can be connected to tanker trucks during truck loading operations. The vapor capture line shall be designed, installed, operated, and maintained to optimize capture efficiency.

"Well Site" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells.

R307-504-3. Applicability.

(1) R307-504-4(1) applies to any person who loads or permits the loading of any intermediate hydrocarbon liquid or produced water at a well site after January 1, 2015.

(2) R307-504-4(2) applies to owners and operators that are required to control emissions from storage vessels in accordance with R307-506.

R307-504-4. Tank Truck Loading Requirements.

(1) Tanker trucks used for intermediate hydrocarbon liquid or produced water shall be loaded using bottom filling or a submerged fill pipe.

(2) VOC emissions during truck loading operations shall be controlled at all times using a vapor capture line. The vapor capture line shall be connected from the tanker truck to a control device or process, resulting in a minimum 95 percent VOC destruction efficiency.

(a) Well sites in operation on January 1, 2018 shall comply with R307-504-4(2) no later than July 1, 2019.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Notice of Continuation: September 5, 2019
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-505. Oil and Gas Industry: Registration Requirements.
R307-505-1. Purpose.

R307-505 establishes requirements for sources in the oil and gas industry to register with the Division.

R307-505-2. Applicability.

(1) R307-505 applies to new and existing operations at a source with Standard Industrial Classification codes in the major group 13, which includes but is not limited to industries involved in oil and natural gas exploration, production, and transmission operations; well production facilities; natural gas compressor stations; natural gas processing plants and commercial oil and gas disposal wells, and evaporation ponds.

(a) A source that is subject to an approval order in accordance with R307-401-8 is exempt from R307-505.

R307-505-3. Registration Requirements.

(1) An owner or operator of a source identified in R307-505-2 that begins operations on or after January 1, 2018, shall register with the director 30 days prior to commencing operation.

(2) An owner or operator of a source identified in R307-505-2 that is in operation before January 1, 2018, shall register with the director by July 1, 2018.

(3) An owner or operator shall update the registration information within 30 days of any of the following:

(a) changes to company name,

(b) removal or addition of control devices, or

(c) termination of operations.

(4) Registration shall be completed online in a format provided by the Division and shall include the following general information: company name, mailing address, source location, source manager or point of contact, process description, capacity and quantity of emitting equipment on-site, fuel type of combustion related equipment (i.e. diesel, natural gas, propane, or field gas), emissions control devices installed, emissions and certification that the facility is in compliance with R307-506 through R307-510.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: January 26, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-506. Oil and Gas Industry: Storage Vessel.
R307-506-1. Purpose.

R307-506 establishes requirements to control emissions of volatile organic compounds (VOCs) from storage vessels associated with a well site.

R307-506-2. Definitions.

"Centralized Tank Battery" means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site.

"Emergency Relief Storage Vessel" means a storage vessel receiving oil, condensate, or produced water as a result of emergency situations, process upsets, or other equipment malfunctions.

"Modification to a well site" means;

(1) a new well is drilled at an existing well site,

(2) a well at an existing well site is hydraulically fractured, or

(3) a well at an existing well site is hydraulically refractured.

"Storage Vessel" means storage vessel as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210.

"Uncontrolled emissions" means actual emissions or the potential to emit without consideration of controls.

R307-506-3. Applicability.

(1) R307-506 applies to each storage vessel located at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-506 shall apply to centralized tank batteries.

(3) R307-506 does not apply to storage vessels that are subject to an approval order issued under R307-401-8.

R307-506-4. Storage Vessel Requirements.

(1) Thief hatches on storage vessels shall be kept closed and latched except during vessel unloading or other maintenance activities.

(2) All storage vessels located at a well site that are in operation as of January 1, 2018, with a site-wide throughput of 8,000 barrels or greater of crude oil or 2,000 barrels or greater of condensate per year on a rolling 12-month basis shall comply with R307-506-4(2)(a) unless the exemption in R307-506-4(2)(b)

applies.

(a) VOC emissions from storage vessels shall either be routed to a process unit where the emissions are recycled, incorporated into a product and/or recovered, or be routed to a VOC control device that is in compliance with R307-508.

(b) All storage vessels located at a well site shall be exempt from R307-506-4(2)(a) if combined VOC emissions are demonstrated to be less than four tons per year of uncontrolled emissions on a rolling 12-month basis.

(i) VOC working and breathing losses, and flash emissions shall be calculated using direct site-specific sampling data and any software program or calculation methodology in use by industry that is based on AP-42 Chapter 7.

(3) All storage vessels that begin operations on or after January 1, 2018, are required to control VOC emissions in accordance with R307-506-4(2)(a) upon startup of operation for a minimum of one year.

(4) An emergency storage vessel located at a well site shall be exempt from R307-506-4(2)(a), if it meets the following requirements:

(i) The emergency storage vessel shall not be used as an active storage tank.

(ii) The owner or operator shall empty the emergency storage vessel no later than 15 days after receiving fluids.

(iii) The emergency storage vessel shall be equipped with a liquid level gauge or equivalent device.

(5) An owner or operator that is required to control emissions in accordance with R307-506-4(2) and R307-506-4(3) shall inspect at least once a month each closed vent system, including vessel openings, thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c).

(a) If defects are discovered, the defects shall be corrected or repaired within 15 days of identification.

(6) Modification to a well site shall require a re-evaluation of site-wide throughput and/or emissions in accordance with R307-506-4(2).

(7) After a minimum of one year of operation, controls may be removed if site-wide throughput is less than 8,000 barrels of crude oil or 2,000 barrels of condensate on a rolling 12-month basis or uncontrolled actual emissions are demonstrated to be less than four tons per year.

R307-506-5. Recordkeeping.

(1) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device shall be kept for three years.

(a) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device shall include the date of the inspection, the status of each closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass device, and the date of corrective action taken if required.

(2) Records of crude oil throughput shall be kept for three years and shall be determined on a monthly basis using the production data reported to the Utah Division of Oil, Gas, and Mining.

(3) Records of emission calculations, actual emissions, and site-specific sampling data used to determine compliance with R307-506-4(2)(b) shall be kept for a period of three years, post registration.

(4) Records of emergency storage vessel usage shall be kept for a period of three years.

(a) Records of emergency storage vessel usage shall include the date the vessel received fluids or was discovered to have received fluids, the date the overflow tank was emptied, and the volume of fluids emptied in barrels.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-507. Oil and Gas Industry: Dehydrators.
R307-507-1. Purpose.

R307-507 establishes requirements to control emissions of volatile organic compounds (VOCs) from dehydrators associated with a well site.

R307-507-2. Definitions.

"Dehydrator" means dehydrator as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210.

"Uncontrolled emissions" means actual or potential emissions without consideration of controls.

R307-507-3. Applicability.

(1) R307-507 applies to each dehydrator located at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-507 shall apply to centralized tank batteries, as defined in R307-506-2.

(3) R307-507 does not apply to a dehydrator that is subject to an approval order issued under R307-401-8.

R307-507-4. Dehydrator Requirements.

(1) Dehydrators with VOC emissions of four tons of uncontrolled emissions per year or greater, either individually or combined with VOC emissions from storage vessels, shall either be routed to a process unit where the emissions are recycled, incorporated into a product, and/or recovered, or be routed to a VOC control device that is in compliance with R307-508. Dehydrators in operation before January 1, 2018, shall determine applicability with calculated actual emissions. Dehydrators in operation on or after January 1, 2018, shall determine applicability using potential to emit.

(2) An owner or operator that is required to control emissions in accordance with R307-507-4(1) shall inspect, at least once a month, each closed vent system, including vessel openings, thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c).

(a) If defects are discovered, the defects shall be corrected or repaired within 15 days of identification.

(3) Modification to a well site shall require a re-evaluation of emissions in accordance with R307-507-4(1).

(4) After a minimum of one year of operation, controls may be removed if uncontrolled actual emissions, individually or

combined with VOC emissions from storage vessels, are less than four tons per year on a rolling 12-month basis.

R307-507-5. Recordkeeping.

(1) Records of emission calculations shall be kept for all periods the plant is in operation if a control device is not installed on-site.

(2) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass devices, shall be kept for three years.

(a) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass devices, shall include the date of the inspection, the status of each closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass devices, and the date of corrective action taken, if required.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-508. Oil and Gas Industry: VOC Control Devices.
R307-508-1. Purpose.

R307-508 establishes requirements for VOC control devices associated with well sites used to control emissions of VOCs.

R307-508-2. Applicability.

(1) R307-508 applies to each VOC control device located at a well site as defined in 40 CFR 60.5430a Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-508 shall apply to centralized tank batteries, as defined in R307-506-2.

(3) R307-508 does not apply to VOC control devices that are subject to an approval order issued under R307-401-8.

R307-508-3. VOC Control Device Requirements.

(1) A VOC control device required by R307-506 or R307-507 must have a control efficiency of 95% or greater.

(a) The VOC control device shall operate with no visible emissions.

(b) The VOC control device must comply with R307-503.

(2) A well site shall demonstrate compliance by meeting the performance test methods and procedures specified in 40 CFR 60.5413.

(3) VOC control devices and all associated equipment shall be inspected monthly by audio, visual, or olfactory (AVO) means to ensure the integrity of the equipment is maintained and is operational. If equipment is not operational, corrective action shall be taken within 15 days of discovery.

R307-508-4. Recordkeeping.

(1) The owneror operator shall keep and maintain records of the VOC control device's control efficiency guaranteed by the manufacturer. These records shall be retained for the life of the control equipment on site.

(2) The owner or operator shall keep and maintain records of the manufacturer's written operating and maintenance instructions. These records shall be retained for the life of the control equipment.

(3) The owner or operator shall keep and maintain records of the VOC control device AVO inspections. These shall be retained for a minimum of three years. These records shall include:

(a) the date of the inspection;

(b) the status of the control device and associated equipment; and

(c) date of corrective action taken, if applicable.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements.
R307-509-1. Purpose.

R307-509 establishes requirements for conducting leak detection and repairs at well sites to control emissions of volatile organic compounds.

R307-509-2. Definitions.

"Difficult-to-Monitor" means difficult-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

"Fugitive emissions" are considered any visible emissions observed using optical gas imaging or a Method 21 instrument reading of 500 ppm or greater.

"Fugitive emissions component" means any component that has the potential to emit fugitive emissions of VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems, thief hatches or other openings, compressors, instruments, and meters.

"Unsafe-to-Monitor" means unsafe-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

R307-509-3. Applicability.

(1) R307-509 applies to each fugitive emissions component at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution and is required to control emissions in accordance with R307-506 and R307-507.

(a) A source meeting the requirements of 40 CFR 60.5397a is meeting the requirements of this rule.

(b) Sources subject to R307-509, are subject until the well is shut in.

(c) R307-509 does not apply to a fugitive emissions component that is subject to an approval order issued under R307-401-8.

R307-509-4. Leak Detection and Repair Requirements.

(1) Applicable sources shall comply with the following:

(a) The owner or operator shall develop an emissions monitoring plan that shall be available upon request to review for each individual well site. At a minimum, the plan shall include:

(i) monitoring frequency;

(ii) monitoring technique and equipment;

(iii) procedures and timeframes for identifying and repairing leaks;

(iv) recordkeeping practices; and

(v) calibration and maintenance procedures for monitoring equipment.

(b) The plan shall address monitoring for difficult-to-monitor and unsafe-to-monitor components.

(c) The owner or operator shall conduct monitoring surveys on site to observe each fugitive emissions component for fugitive emissions.

(d) Monitoring surveys shall be conducted according to the following schedule:

(i) No later than 365 days after January 1, 2018, or no later than 60 days after startup of production, as defined in 40 CFR 60 Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, whichever is later.

(ii) Semiannually after the initial monitoring survey. Consecutive semiannual monitoring surveys shall be conducted at least four months apart.

(iii) Annually after the initial monitoring survey for "difficult-to-monitor" components.

(iv) As required by the owner or operator's monitoring plan for "unsafe-to-monitor" components.

(e) Monitoring surveys shall be conducted using one or both of the following to detect fugitive emissions:

(i) Optical gas imaging (OGI) equipment. OGI equipment shall be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions source.

(ii) Monitoring equipment that meets U.S. EPA Method 21, 40 CFR Part 60, Appendix A.

(f) If fugitive emissions are detected at any time, the owner or operator shall repair the fugitive emissions component as soon as possible but no later than 15 calendar days after detection. If the repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement shall be completed during the next well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 24 months, whichever is earlier.

(g) The owner or operator shall resurvey the repaired or replaced fugitive emission component no later than 30 calendar days after the fugitive emission component was repaired.

R307-509-5. Recordkeeping.

(1) The owner or operator shall maintain records of the emissions monitoring plan. These records shall be retained for the life of the well site.

(2) The owner or operator shall maintain records of the monitoring surveys, repairs, and resurveys. These records shall be

retained for a minimum of three years.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-510. Oil and Gas Industry: Natural Gas Engine Requirements.
R307-510-1. Purpose.

R307-510 establishes control requirements for stationary engines associated with well sites.

R307-510-2. Definitions.

"Site hp" means the total horse power rating of all engines within the boundaries of the source.

R307-510-3. Applicability.

(1) R307-510 applies to each natural gas-fired engine at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, that began operations, installed new engines, or made modifications to existing engines after January 1, 2016.

(2) R307-510 shall apply to centralized tank batteries, as defined in R307-506-2.

(3) R307-510 does not apply to a natural gas-fired engine that is subject to an approval order issued under R307-401-8.

R307-510-4. Engine Requirements.

(1) Regardless of construction, reconstruction, or modification date, each stationary engine at a well site shall comply with the emission standards listed in Table 1 when the engine is installed, relocated, or modified.

Table 1

Maximum Engine hp	Emission Standards in (g/hp-hr)			
	NO_x	CO	VOC	$HC+NO_x$
Equal or greater than 25 hp and < 100 hp	-	4.85	-	2.83
Equal or greater than 100 hp	1.0	2.0	0.7	-

(2) The owner or operator shall either:

(a) purchase a certified stationary internal combustion engine as defined in 40 CFR 60.4248, or

(b) conduct an initial performance test according to 40 CFR 60.4244.

(3) Each engine shall vent exhaust gases vertically unrestricted with the following stack height requirements:

(a) For site hp ratings of 306 or greater, each engine shall have an attached stack height of no less than 10 feet.

(b) For site hp ratings of 151 to 305 hp, each engine shall have an attached stack height of no less than 8 feet.

(c) For site hp ratings of 150 hp or less, there are no stack height requirements on engines.

R307-510-5. Recordkeeping.

For each engine on site, the owner or operator shall maintain records of the engine certification or initial performance test for the period of time the engine is on the well site.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: March 5, 2018
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.

R307-511. Oil and Gas Industry: Associated Gas Flaring.

R307-511-1. Purpose.

R307-511 establishes control requirements for the flaring of produced gas associated with well sites.

R307-511-2. Definitions.

"Emergency release" means a temporary, infrequent and unavoidable situation in which the loss of gas is uncontrollable or necessary to avoid risk of an immediate and substantial adverse impact on safety, public health, or the environment. An "emergency" is limited to a short-term situation of 24 hours or less caused by an unanticipated event or failure that is out of the operator's control and is not due to operator negligence.

"Flaring" means use of a thermal oxidation system designed to combust hydrocarbons in the presence of a flame.

"Associated Gas" means the natural gas that is produced from an oil well during production operations and is either sold, re-injected, used for production purposes, vented (rarely) or flared. Low pressure gas associated with the working, breathing, and flashing of oil is not considered associated gas under this definition and shall be controlled in accordance with R307-506 and R307-507.

R307-511-3. Applicability.

(1) R307-511 applies to each producing well located at a well site as defined in 40 CFR 60.5430a Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) VOC control devices used for controlling associated gas are subject to R307-508.

(3) R307-511 does not apply to producing wells that are subject to an approval order issued under R307-401-8.

R307-511-4. Associated Gas Flaring Requirements.

(1) Associated gas from a completed well shall either be routed to a process unit for combustion, routed to a sales pipeline, or routed to an operating VOC control device except for emergency release situations as defined in R307-511-2.

R307-511-5. Recordkeeping.

(1) The owner or operator shall maintain records for releases under R307-511-4(1)(a).

(a) The time and date of event, volume of emissions and any corrective action taken shall be recorded.

(b) These records shall be kept for a minimum of three years.

KEY: air quality, nonattainment, offset
Date of Enactment or Last Substantive Amendment: March 5, 2019
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Environmental Quality, Dept. of

Air Quality

Chapter 3: General Emission Standards

Effective Date:	02/05/2018 to Current
Rule Type:	Current Rules & Regulations
Reference Number:	020.0002.3.02052018

General Emission Standards

CHAPTER 3

Section 1. **Introduction to general emission standards.**

(a) This Chapter establishes limits on the quantity, rate, or concentration of emissions of air pollutants, including any requirements which limit the level of opacity, prescribe equipment, set fuel specifications, or prescribe operation or maintenance procedures. These general emission standards may be superseded by specific emission standards required in other Chapters of the Wyoming Air Quality Standards and Regulations. Section 9 incorporates by reference all Code of Federal Regulations (CFRs), including their Appendices, cited in this Chapter and all American Society for Testing and Materials (ASTM) standards cited in this Chapter.

Section 2. **Emission standards for particulate matter.**

(a) Visible emissions of any contaminant discharged into the atmosphere from any single new source of emission whatsoever as determined by a qualified observer shall be limited to 20 percent opacity;

Provided, however, that:

(i) An owner or operator of an affected facility of the type described in Chapter 3, Section 2(h)(i) hereof which has a heat input of not less than 2500 x 10^6 Btu per hour, may request the Administrator of the Division of Air Quality to determine opacity of emissions from such affected facility during initial performance tests required by Chapter 3, Section 2(i) or during other performance tests thereafter.

(ii) Upon receipt from such owner or operator of the written report of the results of the performance tests required by Chapter 6, Section 2(i) or later performance tests, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If the Administrator finds that such affected facility is in compliance with all applicable standards for which performance tests are conducted but fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for such affected facility.

(iii) The Administrator will grant such a petition upon a satisfactory demonstration by the owner or operator that such affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions prescribed by the Administrator; and that such affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard at or near the facility's designed capacity.

(iv) The Administrator will establish an opacity standard for such affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard and during which the facility and air pollution equipment is being operated properly and maintained to minimize the opacity of emissions and mass emission rate.

(b) Visible emissions of any contaminant discharged into the atmosphere from any single existing source of emission whatsoever as determined by a qualified observer shall be limited to 40 percent opacity. This limitation shall not apply to existing incinerators or wood waste burners.

(c) The emissions of visible air pollutants from gasoline engines shall be eliminated except for periods not exceeding five consecutive seconds.

(d) The emissions of visible air pollutants from stationary or portable diesel engines as determined by a qualified observer shall be limited to 30 percent opacity below 7500 feet elevation except for periods not exceeding ten consecutive seconds.

(e) Unless restricted by more stringent emission limits established elsewhere in the Wyoming Air Quality Standards and Regulations or permit conditions, any single source may discharge for a period or periods aggregating not more than 6 minutes in any hour contaminants;

(i) Having an equivalent opacity of not more than 40 percent as determined by a qualified observer.

(f) Fugitive Dust. Sources operating within the State of Wyoming are required to control fugitive dust emissions. The following control measures or any equivalent method approved by the Division Administrator shall be considered appropriate for minimizing fugitive dust:

(i) Construction/Demolition Activities.

(A) Any person engaged in clearing or leveling of land, earthmoving, excavation, or movement of trucks or construction equipment over access haul roads or cleared land shall take steps to minimize fugitive dust from such activities. Such control measures may include frequent watering and/or chemical stabilization.

(B) Any person engaged in demolition activities including razing of homes, buildings, or other structures; or removing paving material from roads and/or parking areas shall take steps to minimize fugitive dust from such activities. Such control measures may include frequent watering and/or chemical stabilization.

(C) Any person who is engaged in construction or demolition activities which tracks earth or other materials onto paved streets shall promptly remove such material by water or other means.

(D) Any person engaged in sandblasting or similar operations shall take steps to minimize fugitive dust from such activities. Such control measures may include the installation and use of hood, fans and fabric filters to enclose and vent the handling of dusty materials.

(ii) Handling and Transporting of Materials.

(A) Any person owning, operating or maintaining a new or existing material storage, handling and/or hauling operation shall minimize fugitive dust from such an operation. Such control measures may include the application of asphalt, oil, water or suitable chemicals on unpaved roads, material stockpiles and other surfaces which can give rise to airborne dusts. Control measures for material handling may also include installation and use of hoods, fans and fabric filters to enclose and vent dusty materials.

(B) When transporting materials likely to give rise to airborne dust, open bodied trucks shall be covered when in motion.

(iii) Agricultural Practices.

(A) Any person engaged in agricultural practices, such as tilling of land and application of fertilizers shall operate in a manner as to minimize fugitive dust emissions.

(g) The emission of particulate matter from any new source shall be limited as indicated in Table I. The emission of particulate matter from any existing source shall be limited as indicated in Table II.

(i) Process weight per hour means the total weight of all materials introduced into any specific process that may cause any emissions of particulate matter, including solid fuels, but excluding liquids or gases and used solely as fuels, and excluding air introduced for purposes of combustion, and excluding the weight of any water, water vapor or steam that may be introduced as part of the total materials. However, water contained as part of the normal input to a beet pulp dryer process shall be included as part of the process weight per hour. The process weight rate per hour referred to in this section shall be based upon the maximum design production rate of the equipment unless otherwise restricted by enforceable limits on potential to emit.

(ii) For a cyclical or batch operation, the process weight per hour is derived by dividing the total process weight by the number of hours in one complete operation from the beginning of any given process to the completion thereof, excluding any time during which the equipment is idle.

(iii) For a continuous operation, the process weight per hour is derived by dividing the process weight for a typical period of time.

(iv) Emission tests related to this regulation shall be measured in accordance with the requirements of Chapter 3, Section 2(h)(iv).

TABLE I	
PROCESS WEIGHT RATE (lbs/hr)	**EMISSION RATE (lbs/hr)**
50	0.36
100	0.55
500	1.53
1,000	2.25
5,000	6.34
10,000	9.73
20,000	14.99
60,000	29.60
80,000	31.19
120,000	33.28
160,000	34.85
200,000	36.11
400,000	40.35
1,000,000	46.72

Interpolation of the data in Table I for the process weight rates up to 60,000 lbs/hr shall be accomplished by the use of the equation:

$$E = 3.59\ P^{0.62} \qquad P \leq 30 \text{ tons/hr}$$

and interpolation and extrapolation of the data for process weight rates in excess of 60,000 lbs/hr shall be accomplished by use of the equation:

$$E = 17.31\ P^{0.16} \qquad P > 30 \text{ tons/hr}$$

Where: E = Emissions in pounds per hour.
P = Process weight rate in tons per hour.

TABLE II			
PROCESS WEIGHT RATE	**RATE OF EMISSION**	**PROCESS WEIGHT RATE**	**RATE OF EMISSION**

lb/hr	tons/hr	lb/hr	lb/hr	tons/hr	lb/hr
100	0.05	0.551	16,000	8	16.5
200	0.10	0.877	18,000	9	17.9
400	0.20	1.40	20,000	10	19.2
600	0.30	1.83	30,000	15	25.2
800	0.40	2.22	40,000	20	30.5
1,000	0.50	2.58	50,000	25	35.4
1,500	0.75	3.38	60,000	30	40.0
2,000	1.00	4.10	70,000	35	41.3
2,500	1.25	4.76	80,000	40	42.5
3,000	1.50	5.38	90,000	45	43.6
3,500	1.75	5.96	100,000	50	44.6
4,000	2.00	6.52	120,000	60	46.3
5,000	2.50	7.58	140,000	70	47.8
6,000	3.00	8.56	160,000	80	49.0
7,000	3.50	9.49	200,000	100	51.2
8,000	4.00	10.4	1,000,000	500	69.0
9,000	4.50	11.2	2,000,000	1,000	77.6
10,000	5.00	12.0	6,000,000	3,000	92.7
12,000	6.00	13.6			

Interpolation of the data in Table II for process weight rates up to 60,000 lb/hr shall be accomplished by use of the equation $E = 4.10\ P^{0.67}$, and interpolation and extrapolation of the data for process weight rates in excess of 60,000 lb/hr shall be accomplished by use of the equation:

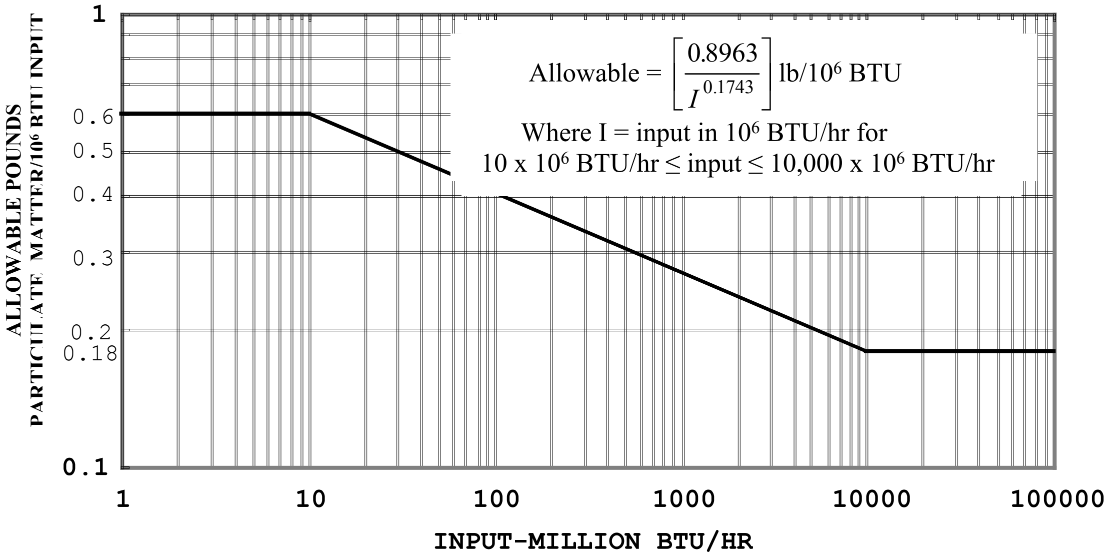
$E = 55.0\ P^{0.11} - 40$, where E = rate of emission in lb/hr

and P = process weight rate in tons/hr

Notwithstanding any other provision of this Table, any existing air contaminant source utilizing an air pollution control device having a collection efficiency of 99.5 percent or better, shall be deemed to be in compliance with all provisions of this regulation. Such efficiency shall be determined by a professional engineer licensed to practice in Wyoming and all expenses incurred in such determination shall be defrayed by the person responsible for the emission.

(h) The emissions of particulate matter from existing sources where fuel burning equipment is used for indirect heating shall be limited as shown in Figure 1 and shall be applicable to equipment burning solid fuel.

FIGURE 1 PARTICULATE EMISSION LIMITS



The emissions of particulate matter from new sources where fuel burning equipment is used for indirect heating shall be limited to 0.10 pound per million Btu input (0.18 grams per million calories) maximum 2-hour average. Except to the extent that an opacity standard has been established for an affected facility pursuant to Chapter 3, Section 2(a)(i) through (iv) hereof, the visible emissions of particulate matter from new sources where fuel burning equipment is used for indirect heating shall be no greater than 20 percent opacity, except that 40 percent opacity shall be permitted for not more than 2 minutes in any hour. This regulation is not applicable to residential or commercial fuel burning equipment with a heat input of less than 10 x 10^6 Btu/hr and used exclusively to produce building heat.

(i) This regulation applies to installations in which fuel is burned for the primary purpose of producing steam, hot water, or hot air or other indirect heating of liquids, gases, or solids, and, in the course of doing so, the products of combustion do not come into direct contact with process materials. Fuels include those such as coal, coke, lignite, fuel oil, and wood, but do not include refuse. When any products or byproducts of a manufacturing process are burned for the same purpose or in conjunction with any fuel, the same maximum emission limitations shall apply.

(ii) For purposes of this regulation, the heat input shall be the aggregate heat content of all fuels whose products of combustion pass through a stack or stacks, or the heat input value used shall be the equipment manufacturer or designer’s guaranteed maximum input, whichever is greater. The total heat input of all fuel burning units at a plant or on a premise shall be used for determining the maximum allowable amount of particulate matter which may be emitted.

(iii) The amount of particulate matter emitted shall be measured by test Methods 1 through 5, Appendix A, 40 CFR part 60. Provided that the Administrator may require that variations to said methods be included or that entirely different methods be utilized if he determines that such variations or different methods are necessary in order for the test data to reflect the actual emission rate of particulate matter.

(i) The emission of particulate matter from any incinerator shall be limited to:

(i) 0.20 pound per 100 pounds (2 grams per kilogram) of refuse charged as determined by a source test method approved by the Division for stationary sources as described in Section 2(h)(ii) of this Chapter;

(ii) A shade or density equal to but not greater than 20 percent opacity as determined by a qualified observer.

Section 3. **Emission standards for nitrogen oxides.**

(a) The emission standards for nitrogen oxides, measured in accordance with Method 7 of 40 CFR part 60, Appendix A or by an equivalent method are:

(i) The emission of nitrogen oxides from new gas fired fuel burning equipment calculated as nitrogen dioxide shall be limited to 0.20 pound per million Btu (0.36 grams per million gram calories) of heat input.

(ii) The emission of nitrogen oxides from existing gas fired fuel burning equipment calculated as nitrogen dioxide shall be limited to 0.23 pound per million Btu (0.41 grams per million gram calories) of heat input.

(iii) The emission of nitrogen oxides from new oil fired fuel burning equipment calculated as nitrogen dioxide shall be limited to 0.30 pounds per million Btu (0.54 grams per million gram calories) of heat input for units having a heat input of 1.0 million Btu per hour (250 million gram calories/hour) or greater and 0.60 pounds per million Btu (1.08 grams per million gram calories) of heat input for units having a heat input less than 1.0 million Btu per hour (250 million gram calories/hour).

(iv) The emission of nitrogen oxides from existing oil fired fuel burning equipment calculated as nitrogen dioxide shall be limited to 0.46 pound per million Btu (0.83 grams per million gram calories) of heat input for units having a heat input of 250 million Btu per hour (62.5 billion gram calories/hour) or greater and 0.60 pound per million Btu (1.08 grams per million gram calories) of heat input for units having a heat input less than 250 million Btu per hour (62.5 billion gram calories/hour).

(v) The emission of nitrogen oxides from new nitric acid manufacturing plants, calculated as nitrogen dioxide shall be limited to 3 pounds per ton (1.5 kilograms per metric ton) of acid produced, maximum 2-hour average.

(vi) The emission of nitrogen oxides from new solid fossil fuel (except lignite) fired fuel burning equipment calculated as nitrogen dioxide shall be limited to 0.70 pounds per million Btu (1.26 grams per million gram calories) heat input.

(vii) The emission of nitrogen oxides from existing solid fossil fuel (except lignite) fired fuel burning equipment calculated as nitrogen dioxide shall be limited to 0.75 pounds per million Btu (1.35 grams per million gram calories) heat input.

Section 4. **[Reserved].**

Section 5. **Emission standards for carbon monoxide.**

(a) The emission of carbon monoxide in stack gases from any stationary source shall be limited as may be necessary to prevent ambient standards described in Chapter 2, Section 5 from being exceeded. Measures considered appropriate for such control are:

(i) Treatment of the waste gas stream by installation and use of a direct flame afterburner or other means which will achieve the required reduction as approved by the Division.

Section 6. **Emission standards for volatile organic compounds.**

(a) The term ***"volatile organic compounds" (VOCs)*** is defined in 40 CFR § 51.100(s), 51.100(s)(1), and 51.100(s)(5), incorporated by reference under Section 9(a) of this chapter.

(b) VOC emissions shall be limited through the application of Best Available Control Technology (BACT) in accordance with Chapter 6, Section 2 of these regulations. Not withstanding the above, whenever acceptable control of VOC emissions from vapor blowdown, emergency relief systems, or VOC emissions generated from oil and gas production, storage, exploration, development, or processing operations is specified pursuant to these regulations as a flare, the flare shall not exceed a 20 percent opacity emission standard. If acceptable control of VOC emissions is specified as a smokeless flare, the definition given in subsection (i) of this section applies.

(i) For the purposes of this section, ***"smokeless flare"*** means a flare designed for and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(ii) Each flare subject to Chapter 3, Section 6(b) must be equipped and operated with an automatic igniter or a continuous burning pilot which must be maintained in good working order.

Section 7. **Emission standards for hydrogen sulfide.**

(a) Any exit process gas stream containing hydrogen sulfide which is discharged to the atmosphere from any source shall be vented, incinerated, flared or otherwise disposed of in such a manner that ambient sulfur dioxide and hydrogen sulfide standards described in Chapter 2, Sections 4 and 7 are not exceeded.

Section 8. **Emission standards of asbestos for demolition, renovation, manufacturing, spraying and fabricating.**

(a) Applicability. The provisions of this section are applicable to those sources specified in paragraphs (g) through (n), (q), and (r).

(b) Definitions. All terms that are used in this section and are not defined below are given the same meaning as in Chapter 1, Section 3 of these regulations.

"Active waste disposal site" means any disposal site other than an inactive site.

"Adequately wet" means sufficiently mix or penetrate with liquid to prevent the release of particulates. If visible emissions are observed coming from asbestos-containing material, then that material has not been adequately wetted. However, the absence of visible emissions is not sufficient evidence of being adequately wet.

"Asbestos" means the asbestiform varieties of serpentinite (chrysotile), riebeckite (crocidolite), cummingtonite-grunerite, anthophyllite, and actinolite-tremolite.

"Asbestos-containing waste materials" means mill tailings or any waste that contains commercial asbestos and is generated by a source subject to the provisions of this section. This term includes filters from control devices, friable asbestos waste material, and bags or other similar packaging contaminated with commercial asbestos. As applied to demolition and renovation operations, this term also includes regulated asbestos-containing material waste and materials contaminated with asbestos including disposable equipment and clothing.

"Asbestos tailings" means any solid waste that contains asbestos and is a product of asbestos mining or milling operations.

"Asbestos waste from control devices" means any waste material that contains asbestos and is collected by a pollution control device.

"Category I nonfriable asbestos-containing material (ACM)" means asbestos-containing packings, gaskets, resilient floor covering, and asphalt roofing products containing more than 1 percent asbestos as determined using the method specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of Asbestos.

"Category II nonfriable ACM" means any material, excluding Category I nonfriable ACM, containing more than 1 percent asbestos as determined using the methods specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of Asbestos that, when dry, cannot be crumbled, pulverized, or reduced to powder by hand pressure.

"Commercial asbestos" means any material containing asbestos that is extracted from ore and has value because of its asbestos content.

"Cutting" means to penetrate with a sharp-edged instrument and includes sawing, but does not include shearing, slicing, or punching.

"Demolition" means the wrecking or taking out of any load-supporting structural member of a facility together with any related handling operations or the intentional burning of any facility.

"Emergency renovation operation" means a renovation operation that was not planned but results from a sudden, unexpected event that, if not immediately attended to, presents a safety or public health hazard, is necessary to protect equipment from damage, or is necessary to avoid imposing an unreasonable financial burden. This term includes operations necessitated by nonroutine failures of equipment.

"Fabricating" means any processing (e.g., cutting, sawing, drilling) of a manufactured product that contains commercial asbestos, with the exception of processing at temporary sites (field fabricating) for the construction or restoration of facilities. In the case of friction products, fabricating includes bonding, debonding, grinding, sawing, drilling, or other similar operations performed as part of fabricating.

"Facility" means any institutional, commercial, public, industrial, or residential structure, installation, or building (including any structure, installation, or building containing condominiums or individual dwelling units operated as a residential cooperative, but excluding residential buildings having four or fewer dwelling units); any ship; and any active or inactive waste disposal site. For the purposes of this definition, any building, structure, or installation that contains a loft used as a dwelling is not considered a residential structure, installation, or building. Any structure, installation or building that was previously subject to this section is not excluded, regardless of its current use or function.

"Facility component" means any part of a facility including equipment.

"Friable asbestos material" means any material containing more than 1 percent asbestos as determined using the method specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of Asbestos, that, when dry, can be crumbled, pulverized, or reduced to powder by hand pressure. If the asbestos content is less than 10 percent as determined by a method other than point counting by polarized light microscopy (PLM), verify the asbestos content by point counting using PLM.

"Fugitive source" means any source of emissions not controlled by an air pollution control device.

"Glove bag" means a sealed compartment with attached inner gloves used for the handling of asbestos-containing materials. Properly installed and used, glove bags provide a small work area enclosure typically used for small-scale asbestos stripping operations. Information on glove-bag installation, equipment and supplies, and work practices is contained in the Occupational Safety and Health Administration's (OSHA's) final rule on occupational exposure to asbestos (29 CFR § 1926.1101(g)(5)(ii)).

"Grinding" means to reduce to powder or small fragments and includes mechanical chipping or drilling.

"In poor condition" means the binding of the material is losing its integrity as indicated by peeling, cracking, or crumbling of the material.

"Inactive waste disposal site" means any disposal site or portion of it where additional asbestos-containing waste material has not been deposited within the past year.

"Installation" means any building or structure or any group of buildings or structures at a single demolition or renovation site that are under the control of the same owner or operator (or owner or operator under common control).

"Leak-tight" means that solids or liquids cannot escape or spill out. It also means dust-tight.

"Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner so that emissions of asbestos are increased. Failures of equipment shall not be considered malfunctions if they are caused in any way by poor maintenance, careless operation, or any other preventable upset conditions, equipment breakdown, or process failure.

"Manufacturing" means the combining of commercial asbestos--or, in the case of woven friction products, the combining of textiles containing commercial asbestos--with any other material(s), including commercial asbestos, and the processing of this combination into a product. Chlorine production is considered a part of manufacturing.

"Natural barrier" means a natural object that effectively precludes or deters access. Natural barriers include physical obstacles such as cliffs, lakes or other large bodies of water, deep and wide ravines, and mountains. Remoteness by itself is not a natural barrier.

"Nonfriable asbestos-containing material" means any material containing more than 1 percent asbestos as determined using the method specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of Asbestos, that, when dry, cannot be crumbled, pulverized, or reduced to powder by hand pressure.

"Nonscheduled renovation operation" means a renovation operation necessitated by the routine failure of equipment, which is expected to occur within a given period based on past operating experience, but for which an exact date cannot be predicted.

"Outside air" means the air outside buildings and structures, including, but not limited to, the air under a bridge or in an open air ferry dock.

"Owner or operator of a demolition or renovation activity" means any person who owns, leases, operates, controls, or supervises the facility being demolished or renovated or any person who owns, leases, operates, controls, or supervises the demolition or renovation operation, or both.

"Particulate asbestos material" means finely divided particles of asbestos or material containing asbestos.

"Planned renovation operations" means a renovation operation, or a number of such operations, in which some RACM will be removed or stripped within a given period of time and that can be predicted. Individual nonscheduled operations are included if a number of such operations can be predicted to occur during a given period of time based on operating experience.

"Regulated asbestos-containing material (RACM)" means: (a) Friable asbestos material, (b) Category I nonfriable ACM that has become friable, (c) Category I nonfriable ACM that will be or has been subjected to sanding, grinding, cutting, or abrading, or (d) Category II nonfriable ACM that has a high probability of becoming or has become crumbled, pulverized, or reduced to powder by the forces expected to act on the material in the course of demolition or renovation operations regulated by this subpart.

"Remove" means to take out RACM or facility components that contain or are covered with RACM from any facility.

"Renovation" means altering a facility or one or more facility components in any way, including the stripping or removal of RACM from a facility component. Operations in which load-supporting structural members are wrecked or taken out are demolitions.

"Resilient floor covering" means asbestos-containing floor tile, including asphalt and vinyl floor tile, and sheet vinyl floor covering containing more than 1 percent asbestos as determined using polarized light microscopy according to the method specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of

Asbestos.

"Strip" means to take off RACM from any part of a facility or facility components.

"Structural member" means any load supporting member of a facility, such as beams and load supporting walls; or any nonload-supporting member, such as ceilings and nonload-supporting walls.

"Visible emissions" means any emissions, which are visually detectable without the aid of instruments, coming from RACM or asbestos-containing waste material, or from any asbestos milling, manufacturing, or fabricating operation. This does not include condensed, uncombined water vapor.

"Waste generator" means any owner or operator of a source covered by this section whose act or process produces asbestos-containing waste material.

"Waste shipment record" means the shipping document, required to be originated and signed by the waste generator, used to track and substantiate the disposal of asbestos-containing waste material.

"Working day" means Monday through Friday and includes holidays that fall on any of the days Monday through Friday.

(c) Units and Abbreviations: Used in this section are abbreviations and symbols of units of measure. These are defined as follows:

(i) System International (SI) Units of Measure:

g = gram
kg = kilogram
m = meter
m^2 = square meter
m^3 = cubic meter

(ii) Other Units of Measure:

C = Celsius (centigrade)
F = Fahrenheit
ft^2 = square feet
ft^3 = cubic feet
yd^2 = square yards
min = minute
oz = ounces

(d) Address: All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this section shall be submitted to the following address:

(i) Wyoming Department of Environmental Quality, Air Quality Division, 122 West 25th Street, Cheyenne, Wyoming 82002.

(e) [Reserved]

(f) Circumvention: No owner or operator shall build, erect, install, or use any article, machine, equipment, process, or method, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous dilutants to achieve compliance with a visible emissions standard, and the piecemeal carrying out of an operation to avoid coverage by a standard that applies only to operations larger than a specified size.

(g) Standard for Waste Disposal for Non-Facility Owners and Operators.

(i) All owners and operators conducting an asbestos abatement project, including an abatement project on a residential building, shall be responsible for complying with Federal requirements and State standards for packaging, transportation, and delivery to an approved waste disposal facility as provided in paragraph (m) of this section. A non-facility is any other facility not defined under the definition of "facility" including residential buildings having four or fewer dwelling units.

(h) Standard for Manufacturing.

(i) Applicability. This paragraph applies to the following manufacturing operations using commercial asbestos.

(A) The manufacture of cloth, cord, wicks, tubing, tape, twine, rope, thread, yarn, roving, lap, or other textile materials.

(B) The manufacture of cement products.

(C) The manufacture of fireproofing and insulating materials.

(D) The manufacture of friction products.

(E) The manufacture of paper, millboard, and felt.

(F) The manufacture of floor tile.

(G) The manufacture of paints, coatings, caulks, adhesives, and sealants.

(H) The manufacture of plastics and rubber materials.

(I) The manufacture of chlorine utilizing asbestos diaphragm technology.

(J) The manufacture of shotgun shell wads.

(K) The manufacture of asphalt concrete.

(ii) Standard. Each owner or operator of any of the manufacturing operations to which this paragraph applies shall either:

(A) Discharge no visible emissions to the outside air from these operations or from any building or structure in which they are conducted or from any fugitive sources; or

(B) Use the methods specified by paragraph (o) of this section to clean emissions containing asbestos material from these operations before they escape to, or are vented to, the outside air.

(C) Monitor each potential source of asbestos emissions from any part of the manufacturing facility, including air cleaning devices, process equipment, and buildings housing material processing and handling equipment, at least once each day during daylight hours for visible emissions to the outside air during periods of operation. The monitoring shall be by the visual observation of at least 15 seconds duration per source of emissions.

(D) Inspect each air cleaning device at least once each week for proper operation and for changes that signal potential for malfunctions, including, to the maximum extent possible without dismantling other than opening the device, the presence of tears, holes, and abrasions in filter bags and for dust deposits on the clean side of bags. For air cleaning devices that cannot be inspected on a weekly basis according to this paragraph, submit to the Administrator, and revise as necessary, a written maintenance plan to include, at a minimum, the following:

(I) Maintenance schedule.

(II) Recordkeeping plan.

(E) Maintain records of the results of visible emission monitoring and air cleaning device inspections using a format similar to that shown in Figures 1 and 2 and include the following:

(I) Date and time of each inspection.

(II) Presence or absence of visible emissions.

(III) Condition of fabric filters, including presence of any tears, holes and abrasions.

Figure 1. Record of Visible Emission Monitoring

Date of Inspection (MM/DD/YY)	Time of Inspection (a.m./p.m.)	Control Device or fugitive emission source designation or number	Visible Emissions Observed (yes/no) Corrective Action taken	Daily Operating Hours	Inspector's Initials

Figure 2. Air Pollution Control Device Inspection Checklist

1. Control Device Designation or Number:_______________

2. Date of Inspection:	______	______	______	______
3. Time of Inspection:	______	______	______	______
4. Is Control Device Operating Properly (yes or no)	______	______	______	______
5. Abrasions in bags (yes or no)	______	______	______	______
6. Dust on Clean Side of bags (yes or no)	______	______	______	______
7. Other Signs of Malfunctions or Potential Mal-functions (yes or no)	______	______	______	______

8. Describe Other Malfunctions or Signs of Potential Malfunctions:

____

9. Describe Corrective Action(s) Taken:

____

10. Date and Time Corrective Action Taken:	______	______	______	______

11. Inspected By:

______	______	______	______
(Print/Type Name)	(Title)	(Signature)	(Date)
______	______	______	______
(Print/Type Name)	(Title)	(Signature)	(Date)

(IV) Presence of dust deposits on clean side of fabric filters.

(V) Brief description of corrective actions taken, including date and time.

(VI) Daily hours of operation for each air cleaning device.

(F) Furnish upon request, and make available at the affected facility during normal business hours for inspection by the Administrator, all records required under this paragraph.

(G) Retain a copy of all monitoring and inspection records for at least 2 years.

(H) Submit quarterly a copy of the visible emission monitoring records to the Administrator if visible emissions occurred during the report period. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter.

(i) Standard for Demolition and Renovation.

(i) Applicability. To determine which requirements of paragraphs (i)(i), (i)(ii), and (i)(iii) apply to the owner or operator of a demolition or renovation activity and prior to the commencement of the demolition or renovation, thoroughly inspect the affected facility or part of the facility where the demolition or renovation operation will occur for the presence of asbestos, including Category I and Category II nonfriable ACM. The requirements of paragraphs (i)(ii) and (i)(iii) apply to each owner or operator of a demolition or renovation activity, including the removal of RACM as follows:

(A) In a facility being demolished, all the requirements of paragraphs (i)(ii) and (i)(iii) apply, except as provided in paragraph (i)(i)(C), if the combined amount of RACM is:

(I) At least 80 linear meters (260 linear feet) on pipes or at least 15 square meters (160 square feet) on other facility components, or

(II) At least 1 cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously.

(B) In a facility being demolished, only the notification requirements of paragraphs (i)(ii)(A), (B), (C)(I) and (IV), and (D)(I) through (D)(IX) and (XVI) apply, if the combined amount of RACM is:

(I) Less than 80 linear meters (260 linear feet) on pipes and less than 15 square meters (160 square feet) on other facility components, and

(II) Less than one cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously or there is no asbestos.

(C) If the facility is being demolished under an order of a State or local government agency, issued because the facility is structurally unsound and in danger of imminent collapse, only the requirements of paragraphs (i)(ii)(A), (i)(ii)(B), (i)(ii)(C)(III), (i)(ii)(D) (except (i)(ii)(D)(VIII)), (i)(ii)(E), and (i)(iii)(D) through (i)(iii)(I) apply.

(D) In a facility being renovated, including any individual nonscheduled renovation operation, all the requirements of paragraphs (i)(ii) and (i)(iii) apply if the combined amount of RACM to be stripped, removed, dislodged, cut, drilled, or similarly disturbed is:

(I) At least 80 linear meters (260 linear feet) on pipe or at least 15 square meters (160 square feet) on other facility components, or

(II) At least 1 cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously.

(III) To determine whether paragraph (i)(i)(D) applies to planned renovation operations involving individual nonscheduled operations, predict the combined additive amount of RACM to be removed or stripped during a calendar year or January 1 through December 31.

(IV) To determine whether paragraph (i)(i)(D) applies to emergency renovation operations, estimate the combined amount of RACM to be removed or stripped as a result of the sudden, unexpected event that necessitated the renovation.

(E) In a facility being renovated, only the notification requirements of paragraphs (i)(ii)(A), (B), (C)(I) and (IV), and (D)(I) through (IX) and (XVI) apply, if the combined amount of RACM is:

(I) Less than 80 linear meters (260 linear feet) on pipes or less than 15 square meters (160 square feet) on other facility components, and

(II) Less than 1 cubic meter (35 cubic feet) off facility components where the length or area could not be measured previously or there is no asbestos.

(ii) Notification Requirements. Each owner or operator of a demolition or renovation activity to which this section applies shall:

(A) Provide the Administrator with written notice of intention to demolish or renovate. Delivery of the notice by U.S. Postal Service, commercial delivery service, or hand delivery is acceptable.

(B) Update notice, as necessary, including when the amount of asbestos affected changes by at least 20 percent.

(C) Postmark or deliver the notice as follows:

(I) At least 10 working days before asbestos stripping or removal work or any other activity begins (such as site preparation that would break up, dislodge or similarly disturb asbestos material), if the operation is described in paragraphs (i)(i)(A) and (D) (except (i)(i)(D)(III) and (i)(i)(D)(IV)). If the operation is as described in paragraph (i)(i)(B), notification is required 10 working days before demolition begins.

(II) At least 10 working days before the end of the calendar year preceding the year for which notice is being given for renovations described in paragraph (i)(i)(D)(III).

(III) As early as possible before, but not later than, the following working day if the operation is a demolition ordered according to paragraph (i)(i)(C) or, if the operation is a renovation described in paragraph (i)(i)(D)(IV).

(IV) For asbestos stripping or removal work in a demolition or renovation operation, described in paragraphs (i)(i)(A) and (D) (except (i)(i)(D)(III) and (i)(i)(D)(IV)), and for a demolition described in paragraph (i)(i)(B), that will begin on a date other than the one contained in the original notice, notice of the new start date must be provided to the Administrator as follows:

(1.) When the asbestos stripping or removal operation or demolition operation covered by this paragraph will begin after the date contained in the notice,

a. Notify the Administrator of the new start date by telephone as soon as possible before the original start date, and

b. Provide the Administrator with a written notice of the new start date as soon as possible before, and no later than, the original start date. Delivery of the updated notice by the U.S. Postal Service, commercial delivery service, or hand delivery is acceptable.

(2.) When the asbestos stripping or removal operation or demolition operation covered by this paragraph will begin on a date earlier than the original start date,

a. Provide the Administrator with a written notice of the new start date at least 10 working days before asbestos stripping or removal work begins.

b. For demolitions covered by paragraph (i)(i)(B), provide the Administrator written notice of a new start date at least 10 working days before commencement of demolition. Delivery of updated notice by U.S. Postal Service, commercial delivery service, or hand delivery is acceptable.

(3.) In no event shall an operation covered by this paragraph begin on a date other than the date contained in the written notice of the new start date.

(D) Include the following in the notice:

(I) An indication of whether the notice is the original or a revised notification.

(II) Name, address, and telephone number of both the facility owner and operator and the asbestos removal contractor owner or operator.

(III) Type of operation: demolition or renovation.

(IV) Description of the facility or affected part of the facility including the size (square meters [square feet] and number of floors), age, and present and prior use of the facility.

(V) Procedure, including analytical methods, employed to detect the presence of RACM and Category I and Category II nonfriable ACM.

(VI) Estimate of the approximate amount of RACM to be removed from the facility in terms of length of pipe in linear meters (linear feet), surface area in square meters (square feet) on other facility components, or volume in cubic meters (cubic feet) if off the facility components. Also estimate the approximate amount of Category I and Category II nonfriable ACM in the affected part of the facility that will not be removed before demolition.

(VII) Location and street address (including building number or name and floor or room number, if appropriate), city, county, and state, or the facility being demolished or renovated.

(VIII) Scheduled starting and completion dates of asbestos removal work (or any other activity, such as site preparation that would break up, dislodge, or similarly disturb asbestos material) in a demolition or renovation; planned renovation operations involving individual nonscheduled operations shall only include the beginning and ending dates of the report period as described in paragraph (i)(i)(D)(III).

(IX) Scheduled starting and completion dates of demolition or renovation.

(X) Description of planned demolition or renovation work to be performed and method(s) to be employed, including demolition or renovation techniques to be used and description of affected facility components.

(XI) Description of work practices and engineering controls to be used to comply with the requirements of this section, including asbestos removal and waste-handling emission control procedures.

(XII) Name and location of the waste disposal site where the asbestos-containing waste material will be deposited.

(XIII) A certification that the individuals supervising and performing the stripping and removal described by this notification have received the training required by paragraph (i)(iii)(H).

(XIV) For facilities described in paragraph (i)(i)(C), the name, title, and authority of the State or local government representative who has ordered the demolition, the date that the order was issued, and the date on which the demolition was ordered to begin. A copy of the order shall be attached to the notification.

(XV) For emergency renovations described in paragraph (b)(xii) of this section, the date and hour that the emergency occurred, a description of the sudden, unexpected event, and an explanation of how the event caused an unsafe condition, or would cause equipment damage or an unreasonable financial burden.

(XVI) Description of procedures to be followed in the event that unexpected RACM is found or Category II nonfriable ACM becomes crumbled, pulverized, or reduced to powder.

(XVII) Name, address, and telephone number of the waste transporter.

(E) The information required in paragraph (i)(ii)(D) must be reported using a form similar to that shown in Figure 3.

(iii) Procedures for Asbestos Emission Control. Each owner or operator of a demolition or renovation activity to whom this paragraph applies, according to paragraph (i)(i), shall comply with the following procedures:

(A) Remove all RACM from a facility being demolished or renovated before any activity begins that would break up, dislodge, or similarly disturb the material or preclude access to the material for subsequent removal. RACM need not be removed before demolition if:

(I) It is Category I nonfriable ACM that is not in poor condition and is not friable.

(II) It is on a facility component that is encased in concrete or other similarly hard material and is adequately wet whenever exposed during demolition; or

(III) It was not accessible for testing and was, therefore, not discovered until after demolition began and, as a result of the demolition, the material cannot be safely removed. If not removed for safety reasons, the exposed RACM and any asbestos-contaminated debris must be treated as asbestos-containing waste material and adequately wet at all times until disposed of.

(IV) They are Category II nonfriable ACM and the probability is low that the materials will become crumbled, pulverized, or reduced to powder during demolition.

(B) When a facility component that contains, is covered with, or is coated with RACM is being taken out of the facility as a unit or in sections:

(I) Adequately wet all RACM exposed during cutting or disjointing operations; and

(II) Carefully lower each unit or section to the floor and to ground level, not dropping, throwing, sliding, or otherwise damaging or disturbing the RACM.

(C) When RACM is stripped from a facility component while it remains in place in the facility, adequately wet the RACM during the stripping operation.

(I) In renovation operations, wetting is not required if:

(1.) The owner or operator has obtained prior written approval from the Administrator based on a written application that wetting to comply with this paragraph would unavoidably damage equipment or present a safety hazard; and

Figure 3
STATE OF WYOMING
NOTIFICATION OF DEMOLITION AND RENOVATION

I. FACILITY DESCRIPTION (INCLUDE BUILDING NAME, NUMBER, AND FLOOR OR ROOM NUMBER)				
BLDG NAME:				
ADDRESS:				
CITY:	STATE”		CONTACT:	
SITE DESCRIPTION (type of material being removed)				
II. FACILITY INFORMATION (IDENTIFY OWNER, REMOVAL CONTRACTOR, AND OTHER OPERATOR)				
OWNER NAME:				
ADDRESS:				
CITY:	STATE:		ZIP:	
CONTACT:				TEL:
REMOVAL CONTRACTOR:				
ADDRESS:				
CITY:	STATE:		ZIP:	
CONTACT:				TEL:
OTHER OPERATOR:				
ADDRESS:				
CITY:	STATE:		ZIP:	
CONTACT:				TEL:
BUILDING SIZE:	NUM OF FLOORS:		AGE IN YEARS:	
PRESENT USE:	PRIOR USE:			
III. TYPE OF OPERATION (D=DEMO O=ORDERED DEMO R=RENOVATION E=EMER. RENOVATION):				
IV. IS ASBESTOS PRESENT? (YES/NO)				
V. PROCEDURE, INCLUDING ANALYTICAL METHOD, IF APPROPRIATE, USED TO DETECT THE PRESENCE OF ASBESTOS MATERIAL:				
VI. SCHEDULED DATES ASBESTOS REMOVAL (MM/DD/YY) START: COMPLETE:				
VII. SCHEDULED DATES DEMO/RENOVATION (MM/DD/YY) START: COMPLETE:				
VIII. SCHEDULED WORK HOURS: START: COMPLETE:				

IX. APPROXIMATE AMOUNT OF ASBESTOS, INCLUDING: 1. REGULATED ACM TO BE REMOVED 2. CATEGORY I ACM NOT REMOVED 3. CATEGORY II ACM NOT REMOVED	RACM TO BE REMOVED	NONFRIABLE ASBESTOS MATERIAL TO BE REMOVED		NONFRIABLE ASBESTOS MATERIAL NOT TO BE REMOVED	
		CAT I	CAT II	CAT I	CAT II
PIPES					
SURFACE AREA					
VOL. RACM OFF FACILITY COMPONENT					

X. DESCRIPTION OF PLANNED DEMOLITION OR RENOVATION WORK, AND METHOD(S) TO BE USED:
XI. DESCRIPTION OF WORK PRACTICES AND ENGINEERING CONTROLS TO BE USED TO PREVENT EMISSIONS OF ASBESTOS AT THE DEMOLITION AND RENOVATION SITE:

Figure 3. NOTIFICATION OF DEMOLITION AND RENOVATION (continued)

XII. TYPE OF NOTIFICATION (O=ORIGINAL R=REVISED C=CANCELLED):		WPR Notice?
XIII. WASTE TRANSPORTER #1		
NAME:		
ADDRESS:		
CITY:	STATE:	ZIP:
CONTACT PERSON:		TELEPHONE:
WASTE TRANSPORTER #2		
NAME:		
ADDRESS:		
CITY:	STATE:	ZIP:
CONTACT PERSON:		TELEPHONE:
XIV. WASTE DISPOSAL SITE		
NAME:		
LOCATION:		
CITY:	STATE:	ZIP:
TELEPHONE:	CONTACT PERSON:	
XV. IF DEMOLITION ORDERED BY A GOVERNMENT AGENCY, PLEASE IDENTIFY THE AGENCY BELOW:		
NAME:	TITLE:	
AUTHORITY:		
DATE OF ORDER (MM/DD/YY):	DATE ORDERED TO BEGIN (MM/DD/YY):	
XVI. FOR EMERGENCY RENOVATIONS		
DATE AND HOUR OF EMERGENCY (MM/DD/YY):		
DESCRIPTION OF THE SUDDEN, UNEXPECTED EVENT:		
EXPLANATION OF HOW THE EVENT CAUSED UNSAFE CONDITIONS OR WOULD CAUSE EQUIPMENT DAMAGE OR AN UNREASONABLE FINANCIAL BURDEN:		
XVII. DESCRIPTION OF PROCEDURES TO BE FOLLOWED IN THE EVENT THAT UNEXPECTED ASBESTOS IS FOUND OR PREVIOUSLY NONFRIABLE ASBESTOS MATERIAL BECOMES CRUMBLED, PULVERIZED, OR REDUCED TO POWDER.		
XVIII. I CERTIFY THAT AN INDIVIDUAL TRAINED IN THE PROVISIONS OF THIS REGULATION (40 CFR PART 61, SUBPART M) WILL BE ON-SITE DURING THE DEMOLITION OR RENOVATION AND EVIDENCE THAT THE REQUIRED TRAINING HAS BEEN ACCOMPLISHED BY THIS PERSON WILL BE AVAILABLE FOR INSPECTION DURING NORMAL BUSINESS HOURS (REQUIRED 1 YEAR AFTER PROMULGATION). ____________________ __________ (SIGNATURE OF OWNER/OPERATOR) (DATE)		
XIX. I CERTIFY THAT THE ABOVE INFORMATION IS CORRECT. ____________________ __________ (SIGNATURE OF OWNER/OPERATOR) (DATE)		

(2.) The owner or operator uses one of the following emission control methods:

a. A local exhaust ventilation and collection system designed and operated to capture the particulate asbestos material produced by the stripping and removal of the asbestos materials. The system must exhibit no visible emissions to the outside air or be designed and operated in accordance with the requirements in paragraph (o).

b. A glove-bag system designed and operated to contain the particulate asbestos material produced by the stripping of the asbestos materials.

c. Leak-tight wrapping to contain all RACM prior to dismantlement.

(II) In renovation operations where wetting would result in equipment damage or a safety hazard, and the methods allowed in paragraph (i)(iii)(C)(I) cannot be used, another method may be used after obtaining written approval from the Administrator based upon a determination that it is equivalent to wetting in controlling emissions or to the methods allowed in paragraph (i)(iii)(C)(I).

(III) A copy of the Administrator's written approval shall be kept at the worksite and made available for inspection.

(D) After a facility component covered with, coated with, or containing RACM has been taken out of the facility as a unit or in sections pursuant to paragraph (i)(iii)(B), it shall be stripped or contained in leak-tight wrapping, except as described in paragraph (i)(iii)(E). If stripped, either:

(I) Adequately wet the RACM during stripping; or

(II) Use a local exhaust ventilation and collection system designed and operated to capture the particulate asbestos material produced by the stripping. The system must exhibit no visible emissions to the outside air or be designed and operated in accordance with the requirements in paragraph (o).

(E) For large facility components such as reactor vessels, large tanks, and steam generators, but not beams (which must be handled in accordance with paragraphs (i)(iii)(B), (C), and (D)), the RACM is not required to be stripped if the following requirements are met:

(I) The component is removed, transported, stored, disposed of, or reused without disturbing or damaging the RACM.

(II) The component is encased in a leak-tight wrapping.

(III) The leak-tight wrapping is labeled according to paragraphs (m)(iv) during all loading and unloading operations and during storage.

(F) For all RACM, including material that has been removed or stripped:

(I) Adequately wet the material and ensure that it remains wet until collected and contained or treated in preparation for disposal in accordance with paragraph (m).

(II) Carefully lower the material to the ground and floor, not dropping, throwing, sliding, or otherwise damaging or disturbing the material.

(III) Transport the material to the ground via leak-tight chutes or containers if it has been removed or stripped more than 50 feet above ground level and was not removed as units or in sections.

(IV) RACM contained in leak-tight wrapping that has been removed in accordance with paragraphs (i)(iii)(D) and (i)(iii)(C)(I)(2.)c. need not be wetted.

(G) When the temperature at the point of wetting is below 0°C (32°F):

(I) The owner or operator need not comply with paragraph (i)(iii)(B)(I) and the wetting provisions of paragraph (i)(iii)(C).

(II) The owner or operator shall remove facility components containing, coated with, or covered with RACM as units or in sections to the maximum extent possible.

(III) During periods when wetting operations are suspended due to freezing temperatures, the owner or operator must record the temperature in the area containing the facility components at the beginning, middle, and end of each workday and keep daily temperature records available for inspection by the Administrator during normal business hours at the demolition or renovation site. The owner or operator shall retain the temperature records for at least 2 years.

(H) No RACM shall be stripped, removed, or otherwise handled or disturbed at a facility regulated by this section unless the individuals supervising and performing the operation have been trained in the provisions of this regulation and the means of complying with them. Asbestos School Hazard Abatement Reauthorization Act (ASHARA) training will be acceptable to meet this requirement. Every year, the individuals supervising and performing asbestos operations shall receive refresher training in the provisions of this regulation. The required training shall include as a minimum: applicability; notifications; material identification; control procedures for removals including, at least, wetting, local exhaust ventilation, negative pressure enclosures, glove-bag procedures, and High Efficiency Particulate Air (HEPA) filters; waste disposal work practices; reporting and recordkeeping; and asbestos hazards and worker protection. Evidence that the required training has been completed shall be posted and made available for inspection by the Administrator at the demolition or renovation site.

(I) For facilities described in paragraph (i)(i)(C), adequately wet the portion of the facility that contains RACM during the wrecking operation.

(J) If a facility is demolished by intentional burning, all RACM including Category I and Category II nonfriable ACM must be removed in accordance with the NESHAP before burning.

(j) Standard for Spraying.

The owner or operator of an operation in which asbestos-containing materials are spray applied shall comply with the following requirements:

(i) For spray-on application on buildings, structures, pipes, and conduits do not use material containing more than 1 percent asbestos as determined using the method specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of Asbestos, except as provided in paragraph (j)(iii).

(ii) For spray-on application of materials that contain more than 1 percent asbestos as determined using the method specified in Appendix J to 29 CFR § 1910.1001, Polarized Light Microscopy of Asbestos, on equipment and machinery, except as provided in paragraph (j)(iii):

(A) Notify the Administrator at least 20 days before beginning the spraying operation. Include the following information in the notice:

(I) Name and address of owner or operator.

(II) Location of spraying operation.

(III) Procedures to be followed to meet the requirements of paragraph (j).

(B) Discharge no visible emissions to the outside air from spray-on application of the asbestos-containing material or use the methods specified by paragraph (o) to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.

(iii) The requirements of paragraphs (j)(i) and (j)(ii) do not apply to the spray-on application of materials where the asbestos fibers in the materials are encapsulated with a bituminous or resinous binder during spraying and the materials are not friable after drying.

(k) Standard for Fabricating.

(i) Applicability. This section applies to the following fabrication operations using commercial asbestos:

(A) The fabrication of cement building products.

(B) The fabrication of friction products, except those operations that primarily install asbestos friction materials on motor vehicles.

(C) The fabrication of cement on silicate board for ventilation hoods; ovens; electrical panels; laboratory furniture, bulkheads, partitions, and ceilings for marine construction; and flow control devices for the molten metal industry.

(ii) Standard. Each owner or operator of any of the fabricating operations to which this section applies shall either:

(A) Discharge no visible emissions to the outside air from any of the operations or from any building or structure in which they are conducted or from any other fugitive sources; or

(B) Use the methods specified by paragraph (o) to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.

(C) Monitor each potential source of asbestos emissions from any part of the fabricating facility, including air cleaning devices, process equipment, and buildings that house equipment for material processing and handling, at least once a day, during daylight hours, for visible emissions to the outside air during periods of operation. The monitoring shall be by visual observation of at least 15 seconds duration per source of emission.

(D) Inspect each air cleaning device at least once each week for proper operation and for changes that signal the potential for malfunctions, including, to the maximum extent possible without dismantling other than opening the device, the presence of tears, holes, and abrasions in the filter bags and for dust deposits on the clean side of bags. For air cleaning devices that cannot be inspected on a weekly basis according to this paragraph, submit to the Administrator, and revise as necessary, a written maintenance plan to include, at a minimum, the following:

(I) Maintenance schedule.

(II) Recordkeeping plan.

(E) Maintain records of the results of visible emission monitoring and air cleaning device inspections using a format similar to that shown in Figures 1 and 2 and include the following:

(I) Date and time of each inspection.

(II) Presence or absence of visible emissions.

(III) Condition of fabric filters, including presence of any tears, holes, and abrasions.

(IV) Presence of dust deposits on clean side of fabric filters.

(V) Brief description of corrective actions taken, including date and time.

(VI) Daily hours of operation for each air cleaning device.

(F) Furnish upon request and make available at the affected facility during normal business hours for inspection by the Administrator, all records required under this paragraph.

(G) Retain a copy of all monitoring and inspection records for at least 2 years.

(H) Submit quarterly a copy of the visible emission monitoring records to the Administrator if visible emissions occurred during the report period. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter.

(l) Standard for Insulating Materials. No owner or operator of a facility may install or reinstall on a facility component any insulating materials that contain commercial asbestos if the materials are either molded and friable or wet-applied and friable after drying. The provisions of this paragraph do not apply to spray-applied insulating materials regulated under paragraph (j).

(m) Standard for Waste Disposal for Non-facilities, Manufacturing, Demolition, Renovation, Spraying, and Fabricating. Each owner or operator of any source covered under the provisions of paragraphs (g), (h), (i), (j), or (k) shall meet the requirements of the Solid Waste Division of the Wyoming Department of Environmental Quality or, at a minimum, the requirements of the following:

(i) Discharge no visible emissions to the outside air during the collection, processing (including incineration), packaging, or transporting of any asbestos-containing waste material generated by the source, or use one of the emission control and waste treatment methods specified in paragraphs (m)(i)(A) through (D).

(A) Adequately wet asbestos-containing waste material as follows:

(I) Mix control device asbestos waste to form a slurry; adequately wet other asbestos-containing waste material; and

(II) Discharge no visible emissions to the outside air from collection, mixing, wetting, and handling operations, or use the methods specified by paragraph (o) to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air; and

(III) After wetting, seal all asbestos-containing waste material in leak-tight containers while wet; or, for materials that will not fit into containers without additional breaking, put materials into leak-tight wrapping; and

(IV) Label the containers or wrapped materials specified in paragraph (m)(i)(A)(III) using warning labels specified by Occupational Safety and Health Standards of the Department of Labor, Occupational Safety and Health Administration (OSHA) under 29 CFR § 1910.1001(j)(4) or § 1926.1101(k)(8). The labels shall be printed in letters of sufficient size and contrast so as to be readily visible and legible.

(V) For asbestos-containing waste material to be transported off the facility site, label containers or wrapped materials with the name of the waste generator and the location at which the waste was generated.

(B) Process asbestos-containing waste material into nonfriable forms as follows:

(I) Form all asbestos-containing waste material into nonfriable pellets or other shapes;

(II) Discharge no visible emissions to the outside air from collection and processing operations, including incineration, or use the method specified by paragraph (o) to clean emissions containing particulate asbestos materials before they escape to, or are vented to, the outside air.

(C) For facilities demolished where the RACM is not removed prior to demolition, adequately wet asbestos-containing waste material at all times after demolition and keep wet during handling and loading for transport to a disposal site. Asbestos-containing waste materials covered by this paragraph do not have to be sealed in leak-tight containers or wrapping but may be transported and disposed of in bulk.

(D) Use an alternative emission control and waste treatment method that has received prior written approval by the EPA Administrator.

(E) As applied to demolition and renovation, the requirements of paragraph (m)(i) do not apply to Category I and Category II nonfriable ACM waste that did not become crumbled, pulverized, or reduced to powder.

(ii) All asbestos-containing waste material shall be deposited as soon as is practical by the waste generator at:

(A) A waste disposal site operated in accordance with the provisions of paragraph (q), or

(B) An EPA-approved site that converts RACM and asbestos-containing waste material into nonasbestos (asbestos-free) material according to the provisions of paragraph (r).

(C) The requirements of paragraph (m)(ii) do not apply to Category I nonfriable ACM that is not RACM.

(iii) Mark vehicles used to transport asbestos-containing waste material during the loading and unloading of waste so that the signs are visible. The markings must:

(A) Be displayed in such a manner and location that a person can easily read the legend.

(B) Conform to the requirements for 51 cm X 36 cm (20 in X 14 in) upright format signs specified in 29 CFR § 1910.145(d)(2) and this paragraph; and

(C) Display the following legend in the lower panel with letter sizes and styles of a visibility at least equal to those specified below.

Legend
DANGER
ASBESTOS DUST HAZARD
CANCER AND LUNG DISEASE HAZARD
Authorized Personnel Only

Notation
2.5 cm (1 inch) Sans Serif, Gothic or Block
2.5 cm (1 inch) Sans Serif, Gothic or Block
1.9 cm (3/4 inch) Sans Serif, Gothic or Block
14 Point Gothic

Spacing between any two lines must be at least equal to the height of the upper of the two lines.

(iv) For All Asbestos-Containing Waste Material Transported Off the Facility Site:

(A) Maintain waste shipment records, using a form similar to that shown in Figure 4, and include the following information:

(I) The name and telephone number of the disposal site operator.

(II) The name and physical site location of the disposal site.

(III) The date transported.

(IV) The name, address, and telephone number of the transporter(s).

<table>
<tr><th colspan="3">GENERATOR</th></tr>
<tr><td>1. Work site name and mailing address</td><td>Owner's name</td><td>Owner's
telephone no.</td></tr>
<tr><td colspan="2">2. Operator's name and address</td><td>Operator's
telephone no.</td></tr>
<tr><td colspan="2">3. Waste disposal site (WDS) name, mailing address, and physical site location</td><td>WDS
telephone no.</td></tr>
<tr><td colspan="3">4. Name and address of responsible agency</td></tr>
<tr><td>5. Description of materials</td><td>6. Containers
No. Type</td><td>7. Total quantity
m^3 (yd^3)</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td colspan="3">8. Special handling instructions and additional information</td></tr>
<tr><td colspan="3">9. OPERATOR'S CERTIFICATION: I hereby declare that the contents of this consignment are fully and accurately described above by proper shipping name and are classified, packed, marked, and labeled, and are in all respects in proper condition for transport by highway according to applicable international and government regulations.</td></tr>
<tr><td>Printed/typed name & title</td><td>Signature</td><td>Month Day Year</td></tr>
<tr><th colspan="3">Transporter</th></tr>
<tr><td colspan="3">10. Transporter 1 (Acknowledgment of receipt of materials)</td></tr>
<tr><td>Printed/typed name & title

Address and telephone no.</td><td>Signature</td><td>Month Day Year</td></tr>
<tr><td colspan="3">11. Transporter 2 (Acknowledgment of receipt of materials)</td></tr>
<tr><td>Printed/typed name & title

Address and telephone no.</td><td>Signature</td><td>Month Day Year</td></tr>
<tr><th colspan="3">Disposal Site</th></tr>
<tr><td colspan="3">12. Discrepancy indication space</td></tr>
<tr><td colspan="3">13. Waste disposal site owner or operator: Certification of receipt of asbestos materials covered by this manifest except as noted in item 12.</td></tr>
<tr><td>Printed/typed name & title</td><td>Signature</td><td>Month Day Year</td></tr>
</table>

Figure 4. Waste Shipment Record

(V) A certification that the contents of this consignment are fully and accurately described by proper shipping name and are classified, packed, marked, and labeled, and are in all respects in proper condition for transport by highway according to applicable international and governmental regulations.

(B) Provide a copy of the waste shipment record, described in paragraph (m)(iv)(A), to the disposal site owners or operators at the same time as the asbestos-containing waste material is delivered to the disposal site.

(C) For waste shipments where a copy of the waste shipment record, signed by the owner or operator of the designated disposal site, is not received by the waste generator within 35 days of the date the waste was accepted by the initial transporter, contact the transporter and/or the owner or operator of the designated disposal site to determine the status of the waste shipment.

(D) Report in writing to the Wyoming Department of Environmental Quality, Air Quality Division, if a copy of the waste shipment record, signed by the owner or operator of the designated waste disposal site, is not received by the waste generator within 45 days of the date the waste was accepted by the initial transporter. Include in the report the following information:

(I) A copy of the waste shipment record for which a confirmation of delivery was not received, and

(II) A cover letter signed by the waste generator explaining the efforts taken to locate the asbestos waste shipment and the results of those efforts.

(E) Retain a copy of all waste shipment records, including a copy of the waste shipment record signed by the owner or operator of the designated waste disposal site, for at least 2 years.

(v) Furnish upon request, and make available for inspection by the Administrator, all records required under this section.

(n) Standard for Inactive Waste Disposal Sites for Manufacturing and Fabricating Operations. Each owner or operator of any inactive waste disposal site that was operated by sources covered under paragraphs (h) or (k) and received deposits of asbestos-containing waste material generated by the sources, shall meet the requirements of the Solid Waste Division of the Wyoming Department of Environmental Quality or at a minimum:

(i) Comply With One of the Following:

(A) Either discharge no visible emissions to the outside air from an inactive waste disposal site subject to the paragraph; or

(B) Cover the asbestos-containing waste material with at least 15 centimeters (6 inches) of compacted nonasbestos-containing material, and grow and maintain a cover of vegetation on the area adequate to prevent exposure of the asbestos-containing waste material. In desert areas where vegetation would be difficult to maintain, at least 8 additional centimeters (3 inches) of well-graded, nonasbestos crushed rock may be placed on top of the final cover instead of vegetation and maintained to prevent emissions; or

(C) Cover the asbestos-containing waste material with at least 60 centimeters (2 feet) of compacted nonasbestos-containing material, and maintain it to prevent exposure of the asbestos-containing waste; or

(D) For inactive waste disposal sites for asbestos tailings, a resinous or petroleum-based dust suppression agent that effectively binds dust to control surface air emissions may be used instead of the methods in paragraphs (n)(i)(A), (B), and (C). Use the agent in the manner and frequency recommended for the particular asbestos tailings by the manufacturer of the dust suppression agent to achieve and maintain dust control. Obtain prior written approval of the Administrator to use other equally effective dust suppression agents. For purposes of this paragraph, any used, spent, or other waste oil is not considered a dust suppression agent.

(ii) Unless a natural barrier adequately deters access by the general public, install and maintain warning signs and fencing as follows, or comply with paragraph (n)(i)(B) or (n)(i)(C).

(A) Display warning signs at all entrances and at intervals of 100 m (328 feet) or less along the property line of the site or along the perimeter of the sections of the site where asbestos-containing waste material was deposited. The warning signs must:

(I) Be posted in such a manner and location that a person can easily read the legend;

(II) Conform to the requirements of 51 cm x 36 cm (20” x 14”) upright format signs specified in 29 CFR § 1910.145(d)(4) and this paragraph; and

(III) Display the following legend in the lower panel with letter sizes and styles of a visibility at least equal to those specified in this paragraph.

Legend

ASBESTOS WASTE DISPOSAL SITE
DO NOT CREATE DUST
Breathing Asbestos is Hazardous to Your Health

Notation
2.5 cm (1 inch) Sans Serif, Gothic or Block
1.9 cm (3/4 inch) Sans Serif, Gothic or Block
14 point Gothic

Spacing between any two lines must be at least equal to the height of the upper of the two lines.

(B) Fence the perimeter of the site in a manner adequate to deter access by the general public.

(C) When requesting a determination on whether a natural barrier adequately deters public access, supply information enabling the Administrator to determine whether a fence or a natural barrier adequately deters access by the general public.

(iii) The owner or operator may use an alternative control method that has received prior approval of the EPA Administrator rather than comply with the requirements of paragraph (n)(i) or (n)(ii).

(iv) Notify the Administrator in writing at least 45 days prior to excavating or otherwise disturbing any asbestos-containing waste material that has been deposited at a waste disposal site under this section, and follow the procedures specified in the notification. If the excavation will begin on a date other than the one contained in the original notice, notice of the new start date must be provided to the Administrator at least 10 working days before excavation begins and in no event shall excavation begin earlier than the date specified in the original notification. Include the following information in the notice:

(A) Scheduled starting and completion dates.

(B) Reason for disturbing the waste.

(C) Procedures to be used to control emissions during the excavation, storage, transport, and ultimate disposal of the excavated asbestos-containing waste material. If deemed necessary, the Administrator may require changes in the emission control procedures to be used.

(D) Location of any temporary storage site and the final disposal site.

(v) Within 60 days of a site becoming inactive and after the effective date of this subpart, record, in accordance with State law, a notation on the deed to the facility property and on any other instrument that would normally be examined during a title search; this notation will in perpetuity notify any potential purchaser of the property that:

(A) The land has been used for the disposal of asbestos-containing waste material;

(B) The survey plot and record of the location and quantity of asbestos-containing waste disposed of within the disposal site required in paragraph (q)(vi) have been filed with the Administrator; and

(C) The site is subject to Chapter 3, Section 8 of the Wyoming Air Quality Standards and Regulations and to 40 CFR part 61, Subpart M.

(o) Air Cleaning.

(i) The owner or operator who uses air cleaning, as specified in paragraphs (h)(ii)(B), (i)(iii)(C)(I)(2.)a., (i)(iii)(D)(II), (j)(ii)(B), (k)(ii)(B), (m)(i)(A)(II), (m)(i)(B)(II) and (r)(v) shall:

(A) Use fabric filter collection devices, except as noted in paragraph (o)(ii), doing all of the following:

(I) Ensuring that the airflow permeability, as determined by ASTM Method D737-04 Test Method for Air Permeability of Textile Fabrics, does not exceed 9 $m^3/min/m^2$ (30 $ft^3/min/ft^2$) for woven fabrics or 11 $m^3/min/m^2$ (35 $ft^3/min/ft^2$) for felted fabrics, except that 12 $m^3/min/m^2$ (40 $ft^3/min/ft^2$) for woven and 14 $m^3/min/m^2$ (45 $ft^3/min/ft^2$) for felted fabrics is allowed for filtering air from asbestos ore dryers;

(II) Ensuring that felted fabric weighs at least 475 grams per square meter (14 ounces per square yard) and is at least 1.6 millimeters (one-sixteenth inch) thick throughout; and

(III) Avoiding the use of synthetic fabrics that contain fill yarn other than that which is spun.

(B) Properly install, use, operate, and maintain all air-cleaning equipment authorized by this paragraph. Bypass devices may be used only during upset or emergency conditions and then only for so long as it takes to shut down the operation generating the particulate asbestos material.

(C) For fabric filter collection devices installed after January 10, 1989, provide for easy inspection for faulty bags.

(ii) There are the following exceptions to paragraph (o)(i)(A):

(A) After January 10, 1989, if the use of fabric creates a fire or explosion hazard, or the Administrator determines that a fabric filter is not feasible, the

Administrator may authorize as a substitute the use of wet collectors designed to operate with a unit contacting energy of at least 9.95 kilopascals (40 inches water gage pressure).

(B) Use a HEPA filter that is certified to be at least 99.97 percent efficient for 0.3 micron particles.

(C) The EPA Administrator may authorize the use of filtering equipment other than described in paragraphs (o)(i)(A) and (o)(ii)(A) and (B) if the owner or operator demonstrates to the EPA Administrator's satisfaction that it is equivalent to the described equipment in filtering particulate asbestos material.

(p) Reporting.

(i) Any new source to which this section applies (with the exception of sources subject to paragraphs (i), (j), and (l)), which has an initial startup date preceding the effective date of this revision, shall provide the following information to the Administrator postmarked or delivered within 90 days of the effective date. In the case of a new source that does not have an initial startup date preceding the effective date, the information shall be provided, postmarked or delivered, within 90 days of the initial startup date. Any owner or operator of an existing source shall provide the following information to the Administrator within 90 days of the effective date of this subpart unless the owner or operator of the existing source has previously provided this information to the Administrator. Any changes in the information provided by any existing source shall be provided to the Administrator, postmarked or delivered, within 30 days after the change.

(A) A description of the emission control equipment used for each process; and

(I) If the fabric device uses a woven fabric, the airflow permeability in $m^3/min/m^2$ and; if the fabric is synthetic, whether the fill yarn is spun or not spun; and

(II) If the fabric filter device uses a felted fabric, the density in g/m^2, the minimum thickness in inches and the airflow permeability in $m^3/min/m^2$.

(B) If a fabric filter device is used to control emissions,

(I) The airflow permeability in $m^3/min/m^2$ ($ft^3/min/ft^2$) if the fabric filter device uses a woven fabric, and, if the fabric is synthetic, whether the fill yarn is spun or not spun; and

(II) If the fabric filter device uses a felted fabric, the density in g/m^2 (oz/yd^2), the minimum thickness in millimeters (inches), and the airflow permeability in $m^3/min/m^2$ ($ft^3/min/ft^2$).

(C) If a HEPA filter is used to control emissions, the certified efficiency.

(D) For sources subject to paragraph (m):

(I) A brief description of each process that generates asbestos-containing waste material;

(II) The average volume of asbestos-containing waste material disposed of measured in m^3/day (yd^3/day);

(III) The emission control methods used in all stages of waste disposal; and

(IV) The type of disposal site or incineration site used for ultimate disposal, the name of the site operator, and the name and location of the disposal site.

(E) For sources subject to paragraphs (n) and (q):

(I) A brief description of the site; and

(II) The method or methods used to comply with the standard, or alternate procedures to be used.

(ii) The information required by paragraph (p)(i) must accompany the information required by 40 CFR part 61, Subpart A, § 61.10. Active waste disposal sites subject to paragraph (q) shall also comply with this provision. Demolition and renovation, spraying, and insulating materials are exempted from the requirements of 40 CFR § 61.10(a). The information described in this paragraph must be reported using the format of Appendix A of CFR 40 part 61 as a guide.

(q) Standard for Active Waste Disposal Sites. Each owner or operator of an active waste disposal site that receives asbestos-containing waste material from a source covered under paragraphs (m) or (r) shall meet the requirements of the Solid Waste Division of the Wyoming Department of Environmental Quality, or at a minimum the following:

(i) Either there must be no visible emissions to the outside air from any active waste disposal site where asbestos-containing waste material has been deposited, or the requirements of paragraph (q)(iii) or (q)(iv) must be met.

(ii) Unless a natural barrier adequately deters access by the general public, either warning signs and fencing must be installed and maintained as follows, or the requirements of paragraph (q)(iii)(A) must be met.

(A) Warning signs must be displayed at all entrances and at intervals of 100 m (330 ft) or less along the property line of the site or along the perimeter of the sections of the site where asbestos-containing waste material is deposited. The warning signs must:

(I) Be posted in such a manner and location that a person can easily read the legend;

(II) Conform to the requirements of 51 cm x 36 cm (20” x 14”) upright format signs specified in 29 CFR § 1910.145(d)(4) and this paragraph; and

(III) Display the following legend in the lower panel with letter sizes and styles of a visibility at least equal to those specified below.

Legend
ASBESTOS WASTE DISPOSAL SITE
DO NOT CREATE DUST
Breathing Asbestos is Hazardous to Your Health

Notation
2.5 cm (1 inch) Sans Serif, Gothic or Block
1.9 cm (3/4 inch) Sans Serif, Gothic or Block
14 point Gothic

Spacing between any two lines must be at least equal to the height of the upper of the two lines.

(B) The perimeter of the disposal site must be fenced in a manner adequate to deter access by the general public.

(C) Upon request and supply of appropriate information, the Administrator will determine whether a fence or a natural barrier adequately deters access by the general public.

(iii) Rather than meet the no visible emission requirement of paragraph (q)(i), at the end of each operating day, or at least once every 24-hour period while the site is in continuous operation, the asbestos-containing waste material that has been deposited at the site during the operating day or previous 24-hour period shall:

(A) Be covered with at least 15 centimeters (6 inches) of compacted nonasbestos-containing material, or

(B) Be covered with a resinous or petroleum-based dust suppression agent that effectively binds dust and controls wind erosion. Such an agent shall be used in the manner and frequency recommended for the particular dust by the dust suppression agent manufacturer to achieve and maintain dust control. Other equally effective dust suppression agents may be used upon prior approval by the Administrator. For purposes of this paragraph, any used, spent, or other waste oil is not considered a dust suppression agent.

(iv) Rather than meet the no visible emission requirement of paragraph (q)(i), use an alternative emissions control method that has received prior written approval by the EPA Administrator.

(v) For all asbestos-containing waste material received, the owner or operator of the active waste disposal site shall:

(A) Maintain waste shipment records, using a form similar to that shown in Figure 4, and include the following information:

(I) The name, address, and telephone number of the waste generator.

(II) The name, address, and telephone number of the transporter(s).

(III) The quantity of the asbestos-containing waste material in cubic meters (cubic yards).

(IV) The presence of improperly enclosed or uncovered waste, or any asbestos-containing waste material not sealed in leak-tight containers.

(V) The date of the receipt.

(B) Upon discovering the presence of a significant amount of improperly enclosed or uncovered waste, report in writing by the following working day to the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the waste generator (identified in the waste shipment record), and, if that office is outside the State of Wyoming, also report in writing by the following working day to the Wyoming Department of Environmental Quality, Air Quality Division. Submit a copy of the waste shipment record along with the report.

(C) As soon as possible and no longer than 30 days after receipt of the waste, send a copy of the signed waste shipment record to the waste generator.

(D) Upon discovering a discrepancy between the quantity of waste designated on the waste shipment records and the quantity actually received, attempt to reconcile the discrepancy with the waste generator. If the discrepancy is not resolved within 15 days after receiving the waste, immediately report in writing to the local, State, or EPA Regional office responsible for administering the asbestos NESHAP program for the waste generator (identified in the waste shipment record), and, if that office is outside the State of Wyoming, also report in writing to the Wyoming Department of Environmental Quality, Air Quality Division. Describe the discrepancy and attempts to reconcile it, and submit a copy of the waste shipment record along with the report.

(E) Retain a copy of all records and reports required by this paragraph for at least 2 years.

(vi) Maintain, until closure, records of the location, depth and area, and quantity in cubic meters (cubic yards) of asbestos-containing waste material within the disposal site on a map or diagram of the disposal area.

(vii) Upon closure, comply with all the provisions of paragraph (n).

(viii) Submit to the Administrator, upon closure of the facility, a copy of records of asbestos waste disposal locations and quantities.

(ix) Furnish upon request, and make available during normal business hours for inspection by the Administrator, all records required under this paragraph.

(x) Notify the Administrator in writing at least 45 days prior to excavating or otherwise disturbing any asbestos-containing waste material that has been deposited at a waste disposal site and is covered. If the excavation will begin on a date other than the one contained in the original notice, notice of the new start date must be provided at least 10 working days before excavation begins and in no event shall excavation begin earlier than the date specified in the original notification. Include the following information in the notice.

(A) Scheduled starting and completion dates.

(B) Reason for disturbing the waste.

(C) Procedures to be used to control emissions during the excavation, storage, transport, and ultimate disposal of the excavated asbestos-containing waste material. If deemed necessary, the Administrator may require changes in the emission control procedures to be used.

(D) Location of any temporary storage site and the final disposal site.

(r) Standard for Operations That Convert Asbestos-Containing Waste Material Into Nonasbestos (Asbestos-Free) Material. Each owner or operator of an operation that converts RACM and asbestos-containing waste material into nonasbestos (asbestos-free) material shall:

(i) Obtain the prior written approval of the EPA Administrator to construct the facility. To obtain approval, the owner or operator shall provide the EPA Administrator with the following information:

(A) Application to construct pursuant to 40 CFR § 61.07.

(B) In addition to the information requirements of 40 CFR § 61.07(b)(3), a

(I) Description of waste feed handling and temporary storage.

(II) Description of process operating conditions.

(III) Description of the handling and temporary storage of the end product.

(IV) Description of the protocol to be followed when analyzing output materials by transmission electron microscopy.

(C) Performance test protocol, including provisions for obtaining information required under paragraph (r)(ii).

(D) The EPA Administrator may require that a demonstration of the process be performed prior to approval of the application to construct.

(ii) Conduct a Start-up Performance Test. Test Results Shall Include:

(A) A detailed description of the types and quantities of nonasbestos material, RACM, and asbestos-containing waste material processed, e.g., asbestos cement products, friable asbestos insulation, plaster, wood, plastic, wire, etc. Test feed is to include the full range of materials that will be encountered in actual operation of the process.

(B) Results of analyses, using polarized light microscopy, that document the asbestos content of the wastes processed.

(C) Results of analyses, using transmission electron microscopy, that document that the output materials are free of asbestos. Samples for analysis are to be collected as 8-hour composite samples (one 200-gram (7-ounce) sample per hour), beginning with the initial introduction of RACM or asbestos-containing waste material and continuing until the end of the performance test.

(D) A description of operation parameters, such as temperature and residence time, defining the full range over which the process is expected to operate to produce nonasbestos (asbestos-free) materials. Specify the limits for each operating parameter within which the process will produce nonasbestos (asbestos-free) materials.

(E) The length of the test.

(iii) During the initial 90 days of operation,

(A) Continuously monitor and log the operating parameters identified during start-up performance tests that are intended to ensure the production of nonasbestos (asbestos-free) output material.

(B) Monitor input materials to ensure that they are consistent with the test feed materials described during start-up performance tests in paragraph (r)(ii)(A).

(C) Collect and analyze samples, taken as 10-day composite samples (one 200-gram (7-ounce) sample collected every 8 hours of operation) of all output material for the presence of asbestos. Composite samples may be for fewer than 10 days. Transmission electron microscopy (TEM) shall be used to analyze the output material for the presence of asbestos. During the initial 90-day period, all output materials must be stored on-site until analysis shows the material to be asbestos-free or disposed of as asbestos-containing waste material according to paragraph (m).

(iv) After the initial 90 days of operation,

(A) Continuously monitor and record the operating parameters identified during start-up performance testing and any subsequent performance testing. Any output produced during a period of deviation from the range of operating conditions established to ensure the production of nonasbestos (asbestos-free) output materials shall be:

(I) Disposed of as asbestos-containing waste material according to paragraph (m), or

(II) Recycled as waste feed during process operation within the established range of operation conditions, or

(III) Stored temporarily on-site in a leak-tight container until analyzed for asbestos content. Any product material that is not asbestos-free shall be either disposed of as asbestos-containing waste material or recycled as waste feed to the process.

(B) Collect and analyze monthly composite samples (one 200-gram (7-ounce) sample collected every 8 hours of operation) of the output material. Transmission electron microscopy shall be used to analyze the output material for the presence of asbestos.

(v) Discharge no visible emissions to the outside air from any part of the operation, or use the methods specified in paragraph (o) to clean emissions containing particulate asbestos material before they escape to, or are vented to, the outside air.

(vi) Maintain Records On-site and Include the Following Information:

(A) Results of start-up performance testing and all subsequent performance testing, including operating parameters, feed characteristic, and analyses of output materials.

(B) Results of the composite analyses required during the initial 90 days of operation under paragraph (r)(iii).

(C) Results of the monthly composite analyses required under paragraph (r)(iv).

(D) Results of continuous monitoring and logs of process operating parameters required under paragraph (r)(iii) and (iv).

(E) The information on waste shipments received as required in paragraph (q).

(F) For output materials where no analyses were performed to determine the presence of asbestos, record the name and location of the purchaser or disposal site to which the output materials were sold or deposited, and the date of sale or disposal.

(G) Retain records required by paragraph (r)(vi) for at least 2 years.

(vii) Submit the Following Reports to the Administrator:

(A) A report for each analysis of product composite samples performed during the initial 90 days of operation.

(B) A quarterly report, including the following information concerning activities during each consecutive 3-month period:

(I) Results of analyses of monthly product composite samples.

(II) A description of any deviation from the operating parameters established during performance testing, the duration of the deviation, and steps taken to correct the deviation.

(III) Disposition of any product produced during a period of deviation, including whether it was recycled, disposed of as asbestos-containing waste material, or stored temporarily on-site until analyzed for asbestos content.

(IV) The information on waste disposal activities as required in paragraph (q).

(viii) Nonasbestos (asbestos-free) output material is not subject to any of the provisions of this section. Output materials in which asbestos is detected, or output materials produced when the operating parameters deviated from those established during the start-up performance testing, unless shown by TEM analysis to be asbestos-free, shall be considered to be asbestos-containing waste and shall be handled and disposed of according to paragraphs (m) and (q) or reprocessed while all of the established operating parameters are being met.

Section 9. **Incorporation by reference.**

(a) Code of Federal Regulations (CFR). All Code of Federal Regulations (CFR), including their Appendices, cited in this Chapter, revised and published as of July 1, 2017, not including any later amendments, are incorporated by reference. Copies of the Code of Federal Regulations are available for public inspection and can be obtained at cost from the Department of Environmental Quality, Division of Air Quality, Cheyenne Office. Contact information for the Cheyenne Office can be obtained at: http://deq.wyoming.gov/. Copies of the CFRs can also be obtained at cost from Government Institutes, 15200 NBN Way, Building B, Blue Ridge Summit, PA 17214, or online at http://www.gpo.gov/fdsys/browse/collectionCfr.action?collectionCode=CFR.

(b) American Society for Testing and Materials (ASTM). All ASTM standards cited in this Chapter, revised and published as of July 1, 2017, not including any later amendments, are incorporated by reference. Copies of the ASTM standards are available for public inspection and can be obtained at cost from the Department of Environmental Quality, Division of Air Quality, Cheyenne Office. Contact information for the Cheyenne Office can be obtained at: http://deq.wyoming.gov/. Copies can also be obtained at cost from the American Society for Testing and Materials, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428-2959, or online at http://www.astm.org/DIGITAL_LIBRARY/index.html.

Carlsbad Current Argus.

LOCAL

New Mexico's oil and gas counties among the most air-polluted in the state amid recent boom

Study from American Lung Association showed highest ozone levels on record between 2017 and 2019.

Adrian Hedden Carlsbad Current-Argus
Published 8:52 a.m. MT Apr. 22, 2021

Story Highlights

- Eddy and Lea counties in Permian Basin given failing grade for ozone pollution.
- Metro areas in New Mexico also suffered from heightened pollution.
- Group advocates for greater controls on emissions from fossil fuel development.

As oil and gas boomed in New Mexico in recent years, air pollution spiked in areas of heavy fossil fuel operations, per a new report from the American Lung Association.

The Association's annual State of the Air Report, published Wednesday, showed increases in ground-level ozone in both Eddy and Lea counties in southeast New Mexico in the prolific Permian Basin shale play, and assigned both counties an "F" grade.

The 2021 report covered 2017, 2018 and 2019 – years that saw an historic increase in oil and gas production before the COVID-19 pandemic led to the industry's decline.

More: U.S. Rep Yvette Herrell calls for New Mexico to oppose Biden's oil and gas policies

Other counties given a failing grade included other oil and gas areas like San Juan County in the northwest San Juan Basin, a region known for mining and natural gas production, along with urban centers Bernalillo and Dona Ana counties.

Albuquerque in Bernalillo County was ranked as the 26th most polluted city in the U.S. based on ozone levels, worsening from its past ranking of 42nd while Las Cruces, near the U.S.-Mexico border, also climbed up from 17th in last year's report to 13th in the 2021 report.

Los Angeles was ranked as the nation's most polluted, followed by three other cities in California with Phoenix at number five.

Eddy County was ranked 24th of the 25 most polluted counties in America, per the report, one of only two rural counties on the list.

Eddy, Lea, Bernalillo and Dona Ana all saw increases in ozone levels during the three years of the study.

More: U.S. Sen. Ben Ray Lujan looks for federal funds to plug abandoned oil and gas wells

Ground-level ozone is created when sunlight interacts with volatile organic compounds (VOCs) such as benzene, which are often byproducts of oil and gas production or vehicle emissions.

To receive a passing grade from the American Lung Association, a county must have an average of 3.2 high-ozone days each year.

More: Permian Basin oil and gas nearing pre-pandemic production levels. Companies seek to cash in

Eddy County was rarely passing since 1996, data in the report showed, as the county was below the passing benchmark between 1999 and 2005 but spiked subsequently for an average of 10.7 high ozone days between 2006 and 2008.

Ozone levels lowered after that to above but near the passing rate with slight upticks before dropping down to passing rates between 2013 and 2016.

Then, from 2017 to 2019, high-ozone days rose drastically to averages of 10.5 days from 2016 to 2018 and then 17.2 between 2017 and 2019 – the highest on record per the Association.

More: New Mexico activists call for oil and gas reform amid Biden's review of federal policy

Lea County, which neighbors Eddy to the east and also within the Permian Basin, appeared to perform better throughout the history of the study.

Although Lea was given a failing grade for the latest study, it passed from 2008 to 2018 with zero high-ozone days between 2007 and 2010.

The latest report showed Lea County had four high-ozone days per the latest report from 2017 to 2019, less than a quarter of Eddy's number.

More: Oil giant BP aims to cut natural gas flaring in the Permian Basin to zero by 2025

Laura Kate Bender, national vice president of healthy air at the American Lung Association said it is known that oil and gas production can emit ozone precursors and that can mean higher levels of air pollution in areas known for heavy fossil fuel operations.

She also worried the Association did not have air monitors in every area where the industry operates or where drilling could occur in the future.

“We know that oil and gas drilling operations lead to some of the precursor pollutants for ozone. We have long called for limits on methane pollution and VOC limits,” Bender said.

“We don’t necessarily have monitors in every area that is impacted by oil and gas operations. We could have unhealthy levels of ozone in areas that people are not being alerted to.”

More: 'It doesn't feel like home anymore." Locals fight oil and gas' impact on Carlsbad area

JoAnna Strother, senior director of advocacy at the American Lung Association said New Mexico’s air pollution put vulnerable populations like children and seniors at increase risk for medical problems asthma, lung cancer or chronic obstructive pulmonary disease (COPD).

Data in the report showed that of Eddy County’s total population of 58,460, about 850 suffered from pediatric asthma in children and 3,614 had adult asthma.

The county also had 2,260 residents suffering from COPD and 20 from Lung Cancer.

More: Data: Energy and oil and gas jobs remain lucrative in New Mexico, nationwide amid COVID-19

There were 15,514 Eddy County residents listed as children under 18, per the report, and 8,535 adults older than 65.

More than half of the county was considered as people of color, or non-white, at 32,004, the report showed.

“Overall, too many people in New Mexico are impacted by unhealthy air - especially children, those over 65, people with COPD, lung cancer or cardiovascular disease and people of color, Strother said.

“Healthy people can also experience shortness of breath and coughing where air pollutants are high. As New Mexicans spend more time outdoors, these pollution levels put them at increased levels of risk – more must be done to protect our health.”

More: New Mexico spent millions plugging abandoned oil and gas wells in 2020

At the state level, New Mexico recently enacted stricter methane emission controls on oil and gas operations, which saw input from environmental and industry groups alike.

Under the new rules adopted by the State's Oil Conservation Division, operators were required to capture 98 percent of produced natural gas by 2026 and end routine flaring, the burning off of excess gas, except for in emergencies.

The New Mexico Oil and Gas Association, a trade group representing 1,000 members in each sector of oil and gas in the state, signaled support of the new regulations as a collaborative effort between industry, government and stakeholders.

"New Mexico relies heavily upon the oil and gas industry for our state budget and funding for public schools, and it is critical that these rules allow our industry to continue to create jobs and revenue amid unprecedented economic challenges," read a statement from the Association.

Adrian Hedden can be reached at 575-618-7631, achedden@currentargus.com or @AdrianHedden on Twitter.

WildEarth GUARDIANS
A FORCE FOR NATURE

March 2, 2021

Jane Nishida
Acting EPA Administrator
Mailcode 1101A
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

Re: Petition to Designate Permian Basin of Southeast New Mexico a Nonattainment Area Due to Ongoing Violations of Ozone Health Standards; Petition to Find New Mexico's State Implementation Plan is Failing to Attain and Maintain Ambient Air Quality Standards

Dear Acting EPA Administrator Nishida:

Enclosed, please find a petition from WildEarth Guardians requesting the U.S. Environmental Protection Agency (EPA) designate the Permian Basin of southeast New Mexico, including Chaves, Eddy, Lea, and Roosevelt Counties, a nonattainment area due to ongoing and severe violations of health standards for ground-level ozone. We also request the EPA assess whether neighboring counties in Texas should be included in any nonattainment area.

As part of this petition, WildEarth Guardians also requests the EPA find that New Mexico's federally approved State Implementation Plan is failing to attain and maintain national ambient air quality standards under the Clean Air Act.

Exhibits to this petition can be downloaded from this online folder, https://drive.google.com/drive/folders/1zBrT-smNLTDGiJ_42bV810QJKPL_qvb8?usp=sharing.

This petition comes as ground-level ozone, the key ingredient of smog, is on the rise in the Permian Basin. This situation poses serious threats to public health, safety, the environment, and environmental justice. In the last five years, ozone concentrations have steadily increased as industrial activity tied to the region's oil and gas extraction boom has exploded. Ozone forming emissions, namely volatile organic compounds and nitrogen oxides, have reached unprecedented highs. The region is now violating health-based national ambient air quality standards for ground-level ozone. This pollution is disproportionately impacting people of color and low income communities.

In light of this mounting air pollution crisis, we call on the EPA to provide relief.

The need to undertake the petitioned actions is critical. Ozone is a significant threat to public health and welfare. The poisonous gas forms when two key pollutants—nitrogen oxides and volatile organic compounds—react with sunlight. Releases from smokestacks, tailpipes, and oil and gas extraction, these ozone forming emissions are considered to be primary ozone "precursors." Although up high, ozone gas protects the Earth's atmosphere, at ground-level, it is dangerous to human health and welfare. The current ambient air quality standards limit ozone concentrations in the ambient air to no more than 0.070 parts per million over an eight-hour period. *See* 40 C.F.R. § 50.19. At high levels, ozone is lethal. However, even at very small concentrations, ozone can cause myriad adverse health impacts, including:

- Increased respiratory symptoms such as irritation of the airways, coughing, or difficulty breathing;
- Decreased lung function;
- Inflammation of airways;
- Asthma attacks; and
- Premature death.

See U.S. EPA, "Health effects of ozone pollution," website available at https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution. According to the EPA, people with lung disease, children, older adults, and even active adults are likely to be more sensitive to the impacts of ozone. EPA has noted that "Children are at greater risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure."

What's more, ozone pollution disproportionately impacts people of color and low income communities, who are more likely to live in proximity to large sources of air pollution, lack sufficient access to health care and information, and be exposed to environmental contamination at school and work.

As indicated by air quality data, ozone is a serious problem in the Permian Basin. Over the years, ozone concentrations have skyrocketed, reaching levels on par with large cities due to unchecked nitrogen oxide and volatile organic compound emissions. This rise in emissions and ozone is linked to booming oil and gas extraction. As oil and gas extraction has increased, emissions have reached new and unprecedented highs. Although the Permian Basin of southeast New Mexico may not have the population size of a big city, the health of its people is just as important.

Making the problem worse, the New Mexico Environment Department has taken the position that the State Implementation Plan prohibits the agency from denying permits for new sources of air pollution that contribute to the region's ozone problem. Although the New Mexico State Implementation Plan prohibits the Department from approving permits that cause or contribute to violations of ambient air quality standards, the Department takes the position that this provision does not apply with regards to ozone. With the Permian Basin violating the ozone NAAQS, the State Implementation Plan is clearly failing to attain the ozone ambient air quality standards.

With the region's ozone problem persisting, the EPA must take swift action to declare the Permian Basin of southeast New Mexico a nonattainment area in order to spur greater control of air pollution in the region. We also urge the EPA to review whether neighboring counties in Texas should also be included in the nonattainment area, particularly counties that have significant oil and gas development.

Undertaking the requested actions will ensure that ozone pollution is reduced, affording greater protection to the people, particularly children, and disproportionately impacted communities, in these areas. Undertaking the requested actions will ensure that the problem is resolved, rather than continuing unabated.

Thank you for your attention to this significant matter of health, environment, and justice.

Sincerely,

Jeremy Nichols
Climate and Energy Program Director
WildEarth Guardians

Cc: Michelle Lujan Grisham, Governor of the State of New Mexico
David Gray, Acting Regional Administrator, EPA Region 6
James Kenney, Secretary, New Mexico Environment Department

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of: Designation of the New Mexico Permian Basin Ozone Nonattainment Area and Call for the Revision of New Mexico State Implementation Plan Over its Failure to Attain and Maintain the National Ambient Air Quality Standards for Ground-level Ozone	Rulemaking petition under the Administrative Procedure 5 U.S.C. § 551, *et seq*., and the Clean Air Act, 42 U.S.C. § 7401, *et seq*. March 2, 2021

PETITION TO THE U.S. ENVIRONMENTAL PROTECTION AGENCY TO:[1]

(1) DESIGNATE THE PERMIAN BASIN OF SOUTHEASTERN NEW MEXICO AS NONATTAINMENT FOR THE OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS; AND

(2) CALL FOR THE REVISION OF THE NEW MEXICO STATE IMPLEMENTATION PLAN DUE TO ITS FAILURE TO ATTAIN AND MAINTAIN THE OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

Ozone levels in the Permian Basin of southeast New Mexico are currently violating the National Ambient Air Quality Standards ("NAAQS") and have been violating now for several years. Driven by unprecedented levels of oil and gas extraction in Chaves, Eddy, Lea, and Roosevelt Counties, ground-level ozone pollution, the key ingredient of smog, has increased to unhealthy levels in the Permian Basin. This dangerous pollution has been fueled by the oil and gas industry flooding the air with emissions of volatile organic compounds ("VOCs") and nitrogen oxides ("NOx"), which react with sunlight to form ozone. It has also been fueled by the New Mexico Environment Department's ("NMED's") refusal to limit this surge in emissions.

High ozone is a serious health risk and poses major environmental justice threats. Ozone is a respiratory irritant and at high levels can be lethal. Even at low concentrations, ozone is

[1] Exhibits to this petition can be downloaded here, https://drive.google.com/drive/folders/1zBrT-smNLTDGiJ_42bV810QJKPL_qvb8?usp=sharing.

linked to difficulty breathing and shortness of breath, coughing and sore or scratchy throat, inflammation and damage of airways, aggravated lung diseases, severe asthma attacks, and even premature death. Children, seniors, and active adults are most vulnerable. Studies have also found that people of color and low income communities are most susceptible to ozone given that they are more likely to live near large sources of air pollution, have inconsistent access to health care and information, and generally face greater exposure to environmental contamination in the home, at work, and in schools.

To protect public health and welfare, the U.S. Environmental Protection Agency ("EPA") has established NAAQS for ozone limiting 8-hour concentrations to no more than 0.070 parts per million ("ppm"). All ozone monitors in southeast New Mexico, including two in Eddy County and one in Lea County, show the region is violating this NAAQS.

Given this serious health and environmental justice matter, WildEarth Guardians petitions the Administrator of the EPA under the Administrative Procedure Act ("APA"), 5 U.S.C. § 551, *et seq.*, the Clean Air Act, 42 U.S.C. § 7401, *et seq.*, and EPA's regulations implementing the Clean Air Act, to urgently designate four counties that comprise the New Mexico portion of the Permian Basin of southeast New Mexico—Chaves, Eddy, Lea, and Roosevelt—as nonattainment for ozone pursuant to Section 107(d)(3) of the Clean Air Act, 42 U.S.C. § 7407(d)(3).[2]

Furthermore, WildEarth Guardians also urgently petitions for the EPA to call for the revision of the New Mexico State Implementation Plan ("SIP") pursuant to Section 110(k)(5) of

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[2] We also request the EPA assess whether it is necessary to include all or portions of neighboring Texas counties in any nonattainment area given their likely contribution to high ozone in southeast New Mexico. These counties similarly contain large amounts of oil and gas extraction activity and are no doubt responsible for producing air pollution that contributes to ozone violations in southeast New Mexico. These counties include, but are not limited to, Andrews, Borden, Cochran, Crane, Culberson, Dawson, Ector, Edwards, Gaines, Garza, Glasscock, Hale, Hockley, Howard, Irion, Lamb, Loving, Lubbock, Lynn, Martin, Midland, Pecos, Reagan, Reeves, Schleicher, Scurry, Sterling, Sutton, Terrell, Terry, Tom Green, Upton, Val Verde, Ward, Winkler, and Yoakum.

the Clean Air Act. 42 U.S.C. § 7410(k)(5). Section 110(k)(5) requires the Administrator to direct a state to revise its SIP if it is "substantially inadequate" to attain or maintain the NAAQS. *Id.* New Mexico acknowledges that available air quality data in southeast New Mexico shows air pollution levels in violation of the NAAQS. Given this, the New Mexico's SIP is substantially inadequate to attain, let alone maintain, the ozone NAAQS, and must be revised.

I. Petitioner

WildEarth Guardians is a Santa Fe, New Mexico-based conservation organization dedicated to protecting and restoring the wildlife, wild rivers, wild places, and health of the American West. WildEarth Guardians' Climate and Energy Program aims to safeguard the western United States from the impacts of climate change, and to advance solutions to confront the climate crisis. On behalf of its members, supporters, and allies, Guardians works to advance policies and actions that help the American West transition away from dependence upon fossil fuel consumption and production, which is not only fueling global climate change, but causing serious air and water pollution problems, despoiling lands, and harming fish and wildlife. Guardians seeks to protect health and the climate by promoting cleaner energy, efficiency and conservation, and alternatives to fossil fuels.

The name and address to whom correspondence regarding this petition should be directed is as follows:

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II. Legal Background

A. The National Ambient Air Quality Standards

Under the Clean Air Act, the Administrator identifies criteria air pollutants that may reasonably be anticipated to endanger public health and welfare. *See* 42 U.S.C. § 7408(a)(1). Once criteria air pollutants are identified, the EPA is required to promulgate NAAQS for such pollutants. *See* 42 U.S.C. § 7409(a). The EPA is obligated to establish primary NAAQS for a criteria pollutant at a level "requisite to protect the public health." *Id*. at § (b)(1). The EPA is also obligated to establish secondary NAAQS for a criteria pollutant at a level "requisite to protect the public welfare[.]" *Id*. at § (b)(2).

Once a NAAQS is promulgated, the EPA must initially identify areas that meet or do not meet the NAAQS within two years. *See* 42 U.S.C. § 7407(d). Any area not meeting the NAAQS is considered to be in nonattainment. *Id*. at § (d)(1)(A)(i). Furthermore, any area that contributes to ambient air quality in a nearby area that does not meet the NAAQS is also considered to be in nonattainment. *Id*.

If air quality data indicates an attainment area is not meeting the NAAQS, the EPA has the responsibility to redesignate the area to nonattainment. *See* 42 U.S.C. § 7407(d)(3). To do so, the EPA must first notify the Governor of a state that available information indicates the designation of the area must be revised from attainment to nonattainment. *Id*. at § 7407(d)(3)(A).[3] Such a notification triggers a 120-day deadline by which the Governor must submit a redesignation to the EPA. *Id*. at § 7407(d)(3)(B). Whether or not the Governor responds, the EPA must promulgate a redesignation within 240 days. *Id*. at § 7407(d)(3)(C).

[3] Moreover, the governor may, on her own motion, request the EPA redesignate an area to nonattainment. 42 U.S.C. § 7407(d)(3)(D).

B. *The 2015 Ozone NAAQS*

In 1971, the EPA identified ground-level ozone as a criteria air pollutant and promulgated ozone NAAQS accordingly. *See* 36 Fed. Reg. 8,186 (Apr. 30, 1971). The EPA revised the current primary and secondary ozone NAAQS in 1997, adopting an 8-hour standard and phasing out the original 1-hour standard, and setting the threshold at 0.08 ppm. *See* 62 Fed. Reg. 38,856 (July 18, 1997). In 2008, the EPA strengthened the 1997 8-hour standard to 0.075 ppm. 73 Fed. Reg. 16436 (March 27, 2008). Responding to mounting scientific data showing a need for stronger NAAQS, in 2015 the EPA again strengthened the primary and secondary NAAQS for ozone to an 8-hour standard of no more than 0.070 ppm. 80 Fed. Reg. 65,292 (Oct. 26, 2015).

A region violates the NAAQS for ozone whenever the three-year average of the annual fourth-highest daily maximum 8-hour average concentration is greater than 0.070 ppm. *See* 40 C.F.R. § 50.19(b). The EPA refers to this three-year average as a "design value." 40 C.F.R. § 51.1100€.

The EPA uses ozone monitors to measure compliance. Ozone monitors measure ground-level ozone in the air using scientific methods specified under 40 C.F.R. § 50.10, Appendix D. The ozone monitors measure ambient concentrations on an hourly basis to calculate the 24 separate 8-hour averages for each day. 40 C.F.R. § 50, Appendix P, at 2.1.

The Clean Air Act directs the EPA to classify redesignated ozone nonattainment areas based on the severity of the violation of the NAAQS. 42 U.S.C. § 7511(b)(1). For air quality control regions in nonattainment status with minimal severity, the Clean Air Act requires the EPA to treat these areas as "marginal." 42 U.S.C. § 7511(a)(1); *see also* 40 C.F.R. 51.1303 (describing nonattainment classifications for 2015 Ozone NAAQS). Once the EPA designates and classifies an ozone nonattainment area, states must bring the area into attainment by a date certain. 42 U.S.C. § 7511(a)(1); 40 C.F.R. § 51.1303. For example, an area whose 8-hour design value fell between 0.071 and 0.081 ppm for ground-level ozone would have three years to return to compliance. 40 C.F.R. § 51.1303.

Finally, where the EPA has redesignated a region to nonattainment for ozone, states must submit State Implementation Plan ("SIP") revisions corresponding to the severity of nonattainment. 42 U.S.C. § 7511a. For example, for "marginal" nonattainment areas (i.e., areas with design values between 0.071 and 0.081 ppm for the 2015 ground-level ozone NAAQS), the SIP revisions must contain evidence of corrective measures taken with respect to control technology, vehicle inspections and emissions, enhanced permitting requirements for stationary sources, and periodic inventories. *Id.* § 5711a(a).

C. EPA must call for a revision of a SIP if it is substantially inadequate

Under the Clean Air Act, a state must prepare and submit a SIP to the EPA in order to attain and maintain the primary and secondary NAAQS, including the ozone NAAQS. 42 U.S.C. § 7410(a). The SIP is a living document that the state and the EPA can and must revise as necessary. The Clean Air Act authorizes the EPA to call for SIP revisions when a SIP is substantially inadequate to attain or maintain the NAAQS. 42 U.S.C. § 7410(k)(5). Indeed, the EPA must "require the State to revise the SIP as necessary to correct such inadequacies." *Id.*

D. EPA has legal authority to act on a citizen rulemaking petition

Guardians petitions the EPA pursuant to the APA's rule-making provisions. *See* 5 U.S.C. § 553€ ("Each agency shall give an interested person the right to petition for the issuance, amendment, or repeal of a rule."). Guardians' request is that the EPA ultimately amend 40 C.F.R. § 81.332 to identify Chaves, Eddy, Lea, and Roosevelt Counties as nonattainment for the 2015 8-hour ozone NAAQS. Further, Guardians also requests that the EPA also issue a call for

New Mexico to revise its SIP. Upon promulgating a call for New Mexico to revise its SIP, EPA will review and ultimately adopt a SIP revision, which will have the effect of revising 40 C.F.R. § 51.1620, *et seq*.

Under the APA, the Administrator has a nondiscretionary duty to "conclude a matter presented to it" in "a reasonable time." 5 U.S.C. § 555(b). A reasonable time is "is typically counted in weeks or months, not years." *In re Am. Rivers & Idaho Rivers United*, 372 F.3d 413, 419 (D.C. Cir. 2004).

E. Environmental Justice

Environmental justice is a part of EPA's mission. Exec. Order No. 12,898, 59 Fed. Reg. 7,629 (Feb. 16, 1994). In furtherance of this mission, President Biden directed his Administration, including the EPA, to:

> [L]isten to the science; to improve public health and protect our environment; to ensure access to clean air and water; to limit exposure to dangerous chemicals and pesticides; to hold polluters accountable, including those who disproportionately harm communities of color and low-income communities; to reduce greenhouse gas emissions; to bolster resilience to the impacts of climate change; to restore and expand our national treasures and monuments; and to prioritize both environmental justice and the creation of the well-paying union jobs necessary to deliver on these goals.

Exec. Order No. 13,990, 86 Fed. Reg. 7,037 (Jan. 25, 2021). President Biden also emphasized

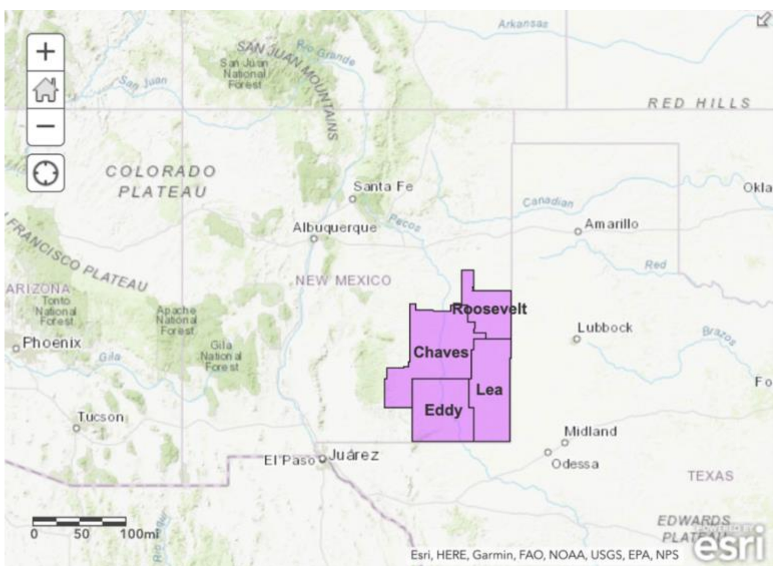
> Agencies shall make achieving environmental justice part of their missions by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts.

Exec. Order No. 14,008, 86 Fed. Reg. 7,619 (Feb. 1, 2021).

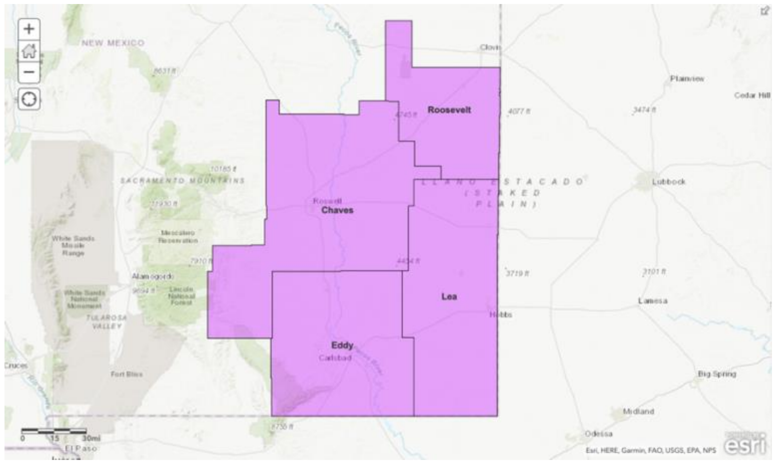
Taken together, the EPA has a duty to ensure its actions improve public health and the environment, ensure access to clean air, and achieve environmental justice. In the context of ground-level ozone pollution, this means the agency must take action to address violations of the ozone NAAQS and ensure attainment and maintenance.

III. Justification for Designating the Permian Basin of New Mexico as Nonattainment for Ozone

We request the EPA designate the Permian Basin of southeast New Mexico as nonattainment for the 2015 ozone NAAQS, a region defined by its extensive oil and gas development. This region includes Chaves, Eddy, Lea, and Roosevelt Counties, which we refer to as the Permian Basin Counties. Within this region, there are ozone monitors in Eddy and Lea Counties that are currently in violation of the 2015 ozone NAAQS. Although there are no ozone monitors in Chaves or Roosevelt Counties, all indications are that air pollution from oil and gas development in these counties contributes to violations of the ozone NAAQS in Eddy and Lea Counties, meaning they should be included in the designation of any nonattainment area.



Location of Chaves, Eddy, Lea, and Roosevelt Counties, the Permian Basin Counties, in New Mexico.



The New Mexico Permian Basin Counties.

The need for the EPA to take action is underscored by the negative health and justice consequences of ozone pollution, clearly documented violations in the Permian Basin, the effects of climate change, and ongoing increases in oil and gas extraction in the region. Below we detail the myriad justifications for designating the Permian Basin nonattainment.

A. *Violations of the ozone NAAQS have been clearly documented, raising serious concerns over the impacts to public health and the environment*

Based solely on current monitoring data, there is ample justification for a nonattainment designation. In 2017, the EPA designated Chaves, Lea, Eddy, and Roosevelt counties as attainment/unclassifiable under the 2015 NAAQS revision for ground-level ozone. Air Quality Designations for the 2015 Ozone NAAQS, 82 Fed. Reg. 54,232, 54,263–64 (Nov. 16, 2017). However, the situation has since become much worse, principally because of the explosion of oil and gas extraction in the area. All three ground-level ozone monitors in the region now have recorded design values in exceedance of 0.070 ppm for the years 2017 through 2019.

Location of ozone monitors (red place-markers) in the Permian Basin of southeast New Mexico. Data from EPA.

Based on EPA design value data available online and monitor value data from the EPA's AirData website, the three primary monitors in the Permian Basin are all currently in violation of the NAAQS.[4]

Fourth Max. and Design Value Data for Eddy and Lea County Ozone Monitors.

County	Monitor ID	2017 4th Highest	2018 4th Highest	2019th Highest	2017–2019 Design Value
Eddy (Carlsbad)	350151005	0.076 ppm	0.083 ppm	0.080 ppm	0.079 ppm
Eddy (Carlsbad Caverns)	350150010	0.065 ppm	0.080 ppm	0.074 ppm	0.073 ppm
Lea (Hobbs)	350250008	0.069 ppm	0.076 ppm	0.070 ppm	0.072 ppm

This elevated ozone pollution is not anomalous. The tables below show that ozone levels in Eddy and Lea Counties have steadily worsened over the last several years, with 19 exceedances of the NAAQS reported in Carlsbad in 2019 and 8-hour ozone levels as high as

[4] Design value data is available at https://www.epa.gov/air-trends/air-quality-design-values (last accessed Feb. 28, 2021). Monitoring value data is available at https://www.epa.gov/outdoor-air-quality-data/monitor-values-report (last accessed Feb. 24, 2021).

0.095 ppm recorded.[5] The design values at monitors in both Lea and Eddy Counties have steadily risen and now three monitors are in violation of the ozone NAAQS. As will be explained further, this worsening of ozone pollution coincides with increases in oil and gas extraction in the region, including the development of new and modified production and processing facilities.

Carlsbad, NM 8-Hour Ozone Readings (in ppm), 2015-2019

	2015	2016	2017	2018	2019
1st Max.	0.069	0.065	0.082	0.096	0.095
2nd Max.	0.068	0.064	0.078	0.095	0.092
3rd Max.	0.067	0.064	0.077	0.091	0.084
4th Max.	0.067	0.063	0.076	0.083	0.080
Number of Days Above NAAQS	0	0	10	18	19

Carlsbad Caverns National Park 8-Hour Ozone Readings, 2015-2019

	2015	2016	2017	2018	2019
1st Max.	0.068	0.070	0.069	0.099	0.082
2nd Max.	0.068	0.069	0.065	0.081	0.080
3rd Max.	0.065	0.069	0.065	0.080	0.078
4th Max.	0.065	0.069	0.065	0.080	0.074
Number of Days Above NAAQS	0	0	0	10	6

Hobbs, NM 8-Hour Ozone Readings (in ppm), 2015-2019

	2015	2016	2017	2018	2019
1st Max.	0.070	0.069	0.080	0.083	0.082
2nd Max.	0.069	0.066	0.074	0.078	0.075
3rd Max.	0.069	0.065	0.072	0.077	0.073
4th Max.	0.067	0.065	0.069	0.076	0.070
Number of Days Above NAAQS	0	0	3	6	3

The region's ozone problem persists to this day. According to monitoring value data from the EPA, 14 exceedances of the 2015 ozone NAAQS were reported in 2020, including nine at the Carlsbad Caverns National Park monitor and five at the Carlsbad monitor. The Carlsbad

[5] Ozone monitoring data from the U.S. Environmental Protection Agency's AirData website, https://www.epa.gov/outdoor-air-quality-data/monitor-values-report (last accessed Feb. 28, 2021).

monitor reported a fourth maximum of 0.073 ppm, placing the monitor's design value at 0.078 ppm, in violation of both the 2008 and 2015 ozone NAAQS. The table below presents ozone exceedance data for the Carlsbad monitor for 2020.

Carlsbad, NM 8-Hour High Ozone Readings (in ppm) in 2020[6]

	Date	8-hour Ozone Concentration
1st Max.	June 24	0.075
2nd Max.	August 21	0.075
3rd Max.	September 3	0.075
4th Max.	August 19	0.073
5th Max.	September 23	0.071

Given ongoing violations of the ozone NAAQS, the EPA must redesignate the Permian Basin, including Chaves, Eddy, Lea, and Roosevelt Counties to nonattainment for the 2015 8-hour ozone NAAQS. Based on quantitative monitoring data, the region is an area "that does not meet . . . the national primary or secondary ambient air quality standard for the pollutant." 42 U.S.C. § 7407(d)(1)(A)(i). The EPA must take action accordingly.

The need for action is underscored by the fact that ground-level ozone poses significant risks to humans and to ecosystems. Ozone creates and exacerbates complications for persons with asthma and other existing respiratory ailments. It causes chronic restrictive pulmonary disease and can even lead to death.[7] Ozone exposure is linked to low-birth weights and lung dysfunction in newborns.[8] To illustrate, the American Lung Association ("ALA") created the chart below to explain how dangerous ozone pollution in Eddy County effects its most vulnerable populations. The ALA gives Eddy County an "F" for its more than 10 annual days of

[6] Ozone concentration data for 2020 obtained from EPA's AirData website at https://www.epa.gov/outdoor-air-quality-data/download-daily-data (last accessed Feb. 28, 2021).
[7] Exhibit 1, *Health Effects of Ground-Level Ozone Pollution*, ENVTL. PROT. AGENCY, https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution (last accessed Feb. 18, 2021).
[8] *Ozone*, AM. LUNG ASSN., https://www.lung.org/clean-air/outdoors/what-makes-air-unhealthy/ozone (last updated Apr. 20, 2020).

unhealthy ozone between 2016 and 2018 and identifies thousands at risk, including those with existing respiratory conditions, children, seniors, the impoverished, and people of color, due to unhealthy levels of air pollution.[9]

Groups At Risk		
Total Population:	57,900	Risks to the population
Pediatric Asthma:	1,154	Risks to people with Asthma
Adult Asthma:	4,180	Risks to people with Asthma
COPD:	2,558	Risks to people with COPD
Lung Cancer:	21	Risks to people with lung cancer
Cardiovascular Disease:	3,314	Risks to people with Cardiovascular Disease
Ever Smoker:	17,140	Risk to people who were Ever Smokers
Children Under 18:	15,344	Risks to children and teens
Adults 65 & Over:	8,406	Risks to older adults
Poverty Estimate:	8,981	Risks to people with low incomes
Non White:	31,228	Risks to people who are Not White

Eddy County Ozone-Specific Epidemiological Data

In addition to its insidious human health effects, ground-level ozone disrupts photosynthesis in a variety of plant species. Of particular concern in the region are the sensitive alpine Ponderosa pine (*Pinus ponderosa*) biotic communities in the surrounding "desert island" mountain ranges.[10]

[9] Exhibit 2, *State of the Air: Eddy County*, AM. LUNG ASSN., http://www.stateoftheair.org/city-rankings/states/new-mexico/eddy.html (last accessed Feb. 28, 2021).
[10] Exhibit 3, *Ecosystem Effects of Ground-Level Ozone*, ENVTL. PROT. AGENCY, https://www.epa.gov/ground-level-ozone-pollution/ecosystem-effects-ozone-pollution (last accessed Feb. 28, 2021); *Ozone Effects on Plants*, NAT. PARK SERV., https://www.nps.gov/subjects/air/nature-ozone.htm (last accessed Feb. 28, 2021).

Map of Carlsbad area, including Carlsbad Caverns and Guadalupe Mountains National Parks

These important pine communities exist within two national parks in the immediate area, both of which are famed for their sensitive and rare ecosystems—Carlsbad Caverns National Park[11] and Guadalupe Mountains National Park.[12] Ground-level ozone negatively impacts the viability of plant and tree species such as the Ponderosa pine by reducing the size of stomata in the leaves or needles—the microscopic boundaries where trees and plants exchange gases with the atmosphere. As the stomata close the trees experience diminished capacity to assimilate carbon.[13] Thus, carbon dioxide levels increase which results in higher carbon dioxide

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[11] *Vascular Plants of Carlsbad Caverns National Park*, NAT. PARK SERV., https://www.nps.gov/cave/learn/nature/plants.htm (last updated Dec. 17, 2017).

[12] Carlsbad Cavern National Park and Guadalupe Mountains National Park are classified as Class I air pursuant to the Clean Air Act's 1990 Amendments. *See* NPS Class I areas, NAT. PARK SERV., https://www.nps.gov/subjects/air/npsclass1.htm (last updated Mar. 13, 2018).

[13] Exhibit 4, Silvano Fares et al., *Tropospheric Ozone Reduces Carbon Assimilation in Trees: Estimates from Analysis of Continuous Flux Measurements*, 19 GLOBAL CHANGE BIOLOGY 2427 (2013) (reporting 12–19% reduction in carbon assimilation in Ponderosa pine at ground-level ozone concentrations of between 60 and 100 ppb).

concentrations in the atmosphere. In the long run, ground-level ozone damages the needles of the Ponderosa pine, inhibiting growth, and potentially inducing a cascade of biotic shifts in the area.

Coupled with documented violations of the ozone NAAQS, the serious health and environmental consequences should compel the EPA to act. It is imperative the agency designate the Permian Basin as nonattainment to ensure a full and effective cleanup of the region's ozone and full protection of public health and the environment.

B. Ozone is a serious environmental justice problem

High ozone in the Permian Basin of New Mexico also poses serious environmental justice concerns.

It is well established that low income and minority communities tend to experience disproportionately higher levels of air pollution.[14] With regards to ozone, reports have found a high association between racial isolation and elevated pollution levels, particularly in the rural and suburban western United States.[15] While ozone may disproportionately impact people of color and low income communities, other forms of air pollution also pose disproportionately impacts, heightening the dangers that ozone poses to health and welfare.

Many studies have looked at differences in the impact of air pollution on premature death. Recent studies have looked at the mortality in the Medicaid population and found that those who live in predominately black or African American communities suffered greater risk of premature death from particle pollution than those who live in communities that are

[14] Exhibit 5, Miranda, M.L., S.E. Edwards, M.H. Keating, and C.J. Paul, "Making the environmental justice grade: the relative burden of air pollution exposure in the United States," *Int. J. Environ. Res. Public Health*, 2011 June; 8(6): 1755-1771.

[15] Exhibit 6, Bravo, M.A., R. Anthopolos, M.L. Bell, M.L. Miranda, "Racial isolation and exposure to airborne particulate matter and ozone in understudied US populations: environmental justice applications of downscaled numerical model output," *Env. Int.*, 2016, 92-93: 247-255.

predominately white.[16] Another large study found that Hispanics and Asians, but especially blacks, had a higher risk of premature death from particle pollution than whites did. This study found that income did not drive the differences. Higher-income blacks who had higher income than many whites still faced greater risk than those whites, suggesting that the impact of other factors such as chronic stress as a result of discrimination may be playing a role.[17] Other researchers have found greater risk for African Americans from hazardous air pollutants, including those pollutants that also come from traffic sources.[18] Due to decades of residential segregation, African Americans tend to live where there is greater exposure to air pollution.[19]

Socioeconomic position also appears tied to greater harm from air pollution. Multiple large studies show evidence of that link. Low socioeconomic status consistently increased the risk of premature death from fine particle pollution among 13.2 million Medicare recipients studied in the largest examination of particle pollution-related mortality nationwide.[20] In a 2008 study that found greater risk for premature death for communities with higher African American populations, researchers also found greater risk for people living in areas with higher unemployment.[21] A 2008 study of Washington, DC, found that while poor air quality and worsened asthma went hand in hand in areas where Medicaid enrollment was high, the areas with the highest Medicaid enrollment did not always have the strongest association of high air

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[16] Kioumourtzoglou M.A., Schwartz J., James P., Dominici F., Zanobetti A. "PM2.5 and mortality in 207 us cities: Modification by temperature and city characteristics." *Epidemiology*, 2016; 27: 221-227.

[17] Di, Q., Y. Wang, A. Zonobetti, Y. Wang, P. Koutrakis, C. Choirat, F. Dominici, J.D. Schwartz, "Air pollution and mortality in the Medicare population," *N. Engl. J. Med.*, 2017; 376: 2513-2522.

[18] Apelberg B.J., T.J. Buckley, R.H. White, "Socioeconomic and racial disparities in cancer risk from air toxics in Maryland," *Environ. Health Perspect*. 2005: 113: 693-699.

[19] Nardone A., J.A. Casey, R. Morello-Frosch, M. Mujahid, J.R. Balmes, N. Thakur, "Associations between historical residential redlining and current age-adjusted rates of emergency department visits due to asthma across eight cities in California: an ecological study," *Lancet Planet Health*. 2020:4(1):e24-e31.

[20] Zeger S.L., F. Dominici, A. McDermott, J. Samet, "Mortality in the Medicare population and chronic exposure to fine particulate air pollution in urban centers (2000-2005)," *Environ. Health Perspect*. 2008: 116: 1614-1619.

[21] Bell M.L., F. Dominici, "Effect modification by community characteristics on the short-term effects of ozone exposure and mortality in 98 US communities," *Am. J. Epidemiol*. 2008; 167: 986-997

pollution and asthma attacks.[22] A 2016 study of New Jersey residents found that the risk of dying early from long-term exposure to particle pollution was higher in communities with larger African American populations, lower home values and lower median income.[23] Studies of Atlanta, GA, found that particle pollution increased the risk of asthma attacks for zip codes where poverty was high and among people eligible for Medicaid.[24]

Scientists have speculated that there are three broad reasons why disparities may exist. First, groups may face greater exposure to pollution because of factors ranging from racism to class bias to housing market dynamics and land costs. For example, pollution sources tend to be located near disadvantaged communities, increasing exposure to harmful pollutants. Second, low social position may make some groups more susceptible to health threats because of factors related to their disadvantage. Lack of access to health care, grocery stores and good jobs; poorer job opportunities; dirtier workplaces; and higher traffic exposure are among the factors that could handicap groups and increase the risk of harm. Finally, existing health conditions, behaviors or traits may predispose some groups to greater risk. For example, people of color are among the groups most at risk from air pollutants, and the elderly, African Americans, Latinos and people living near a central city have higher incidence of diabetes.

People of color also may be more likely to live in counties with higher levels of pollution. Non-Hispanic blacks and Hispanics were more likely to live in counties that had worse problems

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[22] Babin S., H. Burkom, R. Holtry, N. Tabernero, J. Davies-Cole, L. Stokes, K. Dehaan, D. Lee, "Medicaid patient asthma-related acute care visits and their associations with ozone and particulates in Washington, DC, from 1994-2005," *Int. J. Environ. Health Res*. 2008; 18 (3): 209-221.
[23] Wang Y., I. Kloog, B.A. Coul, A. Kosheleva, A. Zanobetti, J.D. Schwartz, "Estimating causal effects of long-term PM2.5 exposure on mortality in New Jersey," *Environ. Health Perspec*t. 2016; 124: 1182-1188.
[24] O'Lenick, C.R., *et al*., "Assessment of neighbourhood-level socioeconomic status as a modifier of air pollution-asthma associations among children in Atlanta," *J. Epi. Comm. Health*. 2017:71(2):129-136; Strickland M.J., *et al*. "Modification of the effect of ambient air pollution on pediatric asthma emergency visits: susceptible subpopulations," *Epidemiology*. 2014; 25: 843-850.

with particle pollution, researchers found in a 2011 analysis. Non-Hispanic blacks were also more likely to live in counties with worse ozone pollution. Income groups, by contrast, differed little in these exposures. However, since few rural counties have monitors, the primarily older, non-Hispanic white residents of those counties lack information about the air quality in their communities.[25]

Like most anywhere else in the United States, the Permian Basin Counties of New Mexico face significant environmental justice risks from air pollution. According to the U.S. Census Bureau, within this region, there are Black people and communities, Hispanic and Latino people and communities, Indigenous people and communities, and a substantial number of people living in poverty. Given the region's high ozone pollution, there is every reason to conclude that these people and communities are experiencing disproportionate impacts, further warranting action by the EPA to designate the region as nonattainment for the 2015 ozone NAAQS.

Racial and Demographic data for the Permian Basin Counties in New Mexico. Data from the U.S. Census Bureau.[26]

Racial and Economic Demographic	Chaves	Eddy	Lea	Roosevelt
Black or African American	2.4%	2.0%	4.3%	2.9%
American Indian	2.4%	2.4%	2.0%	2.3%
Hispanic or Latino	57.8%	50.5%	60.1%	43.2%
Persons in poverty	18.1%	11.2%	18.2%	18.8%

C. <u>High ozone is being fueled by a surge oil and gas extraction activity in the Permian Basin</u>

The need to designate the Permian Basin as nonattainment is underscored by a surge in oil and gas extraction in the region, and the resulting release of ozone precursor emissions, particularly VOCs and NOx.

[25] *Supra* note 13.
[26] Data queried from the U.S. Census Bureau's "Quick Facts" website, available at https://www.census.gov/quickfacts/fact/table/US/PST045219 (last accessed Feb. 28, 2021).

The Permian Basin of New Mexico, including Chaves, Eddy, Lea, and Roosevelt Counties, has experienced explosive growth in oil and gas production in recent years.[27] U.S. Energy Information Agency ("EIA") data indicate that in December 2015, New Mexico produced 20,801 MMcf of natural gas from shale gas deposits. By December 2018, that number had climbed four-fold to more than 80,000 MMcf. The story is much the same for oil. Between December 2015 and December 2018, New Mexico's crude oil production rose from 11,139 Mbbl annually to 33,414 Mbbl, an astonishing tripling of production. These numbers have helped propel New Mexico into the position as the country's third leading producer of oil and gas.

The Permian Basin has driven much of New Mexico's growth in oil and gas production in recent years. The Basin contains "one of the largest hydrocarbon plays in the United States," the Wolfcamp Play.[28] The United States Geological Survey ("USGS") estimates the Wolfcamp Play contains more than 19 billion barrels of oil and 16 trillion cubic feet of natural gas. *Id.* On a wider scale, USGS's recent 2018 report detailing the continuous oil and gas reserves in the Wolfcamp and Bone Springs formations shed some light on just what is at stake for the prospect of future oil and gas production in the region. Together, the Bone Springs and Wolfcamp plays contain about 46.3 billion barrels of oil, 281 trillion cubic feet of gas, and 20 billion barrels of natural gas liquids.[29]

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[27] The Permian Basin of New Mexico centers on Eddy and Lea Counties, but due to increased oil and gas production in Chaves and Roosevelt counties, and their proximity to dangerous ozone concentrations just to the south, EPA should redesignate all four counties as nonattainment as well. *See* Exhibit 7, Grant, J., R. Parikh, A. Bar-Ilan, *Future Year 2028 Emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin*, Final Report Prepared for Bureau of Land Management, Western States Air Resources Council, and Western Regional Air Partnership. (August 2018), https://www.wrapair2.org/pdf/SanJuan_Permian_Futureyear_EI_Report_21Aug2018.pdf.

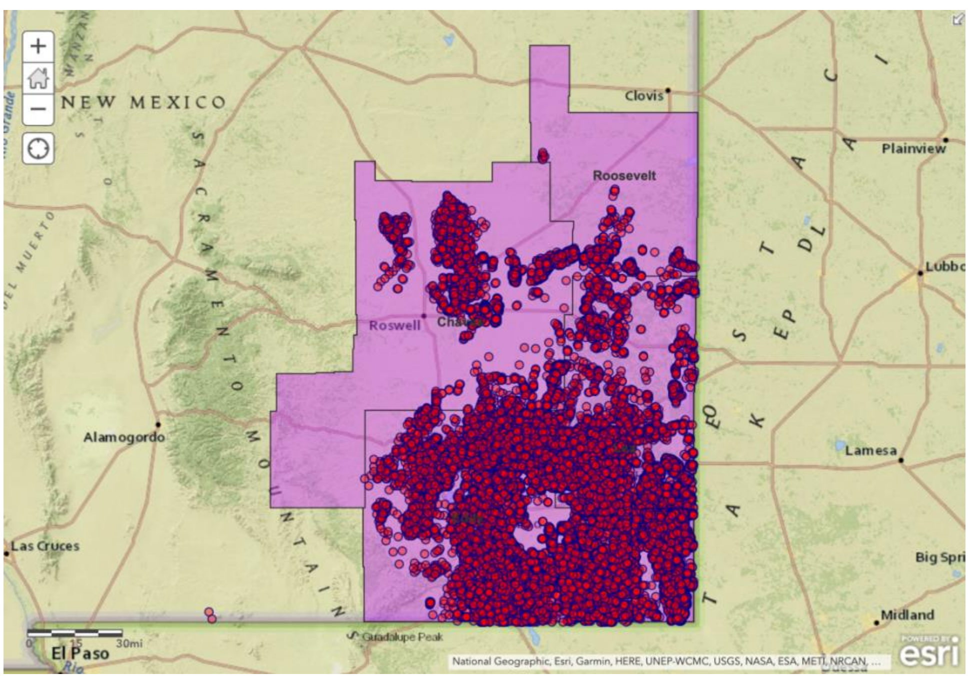
[28] Exhibit 8, *Permian Basin: Wolfcamp Oil Shale Play*, U.S. ENERGY INFO. ADMINISTRATION 8 (Oct. 2018).

[29] Exhibit 9, *Assessment of Undiscovered Continuous Oil and Gas Resources in the Wolfcamp Shale and Bone Spring Formation of the Delaware Basin, Permian Basin Province, New Mexico and Texas, 2018,* U.S. GEOLOGICAL SURVEY (Nov. 28, 2018), https://pubs.er.usgs.gov/publication/fs20183073.

EIA statistics show that oil and gas production in the region has grown dramatically. Tight oil production from the Wolfcamp Shale and Bone Spring Formation has risen from about 0.046 million barrels per day in January 2000, to 1.836 million barrels per day in January 2019, nearly a 40-fold increase. Since 2010, oil production in the Permian Basin has grown from less than 1 million barrels per day to 4 million barrels per day, with production nearly doubling in the past two years alone. Thousands of active wells now pockmark the region.

Active Oil, Gas, and Injection Wells in the Permian Basin of New Mexico as of February 2021.[30]

County	# Active Oil Wells	# Active Gas Wells	# Active Injection Wells
Chaves	1,062	1,263	152
Eddy	10,777	3,065	742
Lea	12,335	1,840	2,094
Roosevelt	351	53	33



Active oil, gas, and injection wells in the Permian Basin Counties of southeast New Mexico. Data from New Mexico Oil Conservation Division.[31]

[30] Data from New Mexico Oil Conservation Division, https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting/Data/Wells.aspx (last accessed Feb. 28, 2021).
[31] Geographic data available for download from the New Mexico Oil Conservation Division's Public FTP site, ftp://164.64.106.6/Public/OCD/OCD%20GIS%20Data/.

The EPA has identified oil and gas production as the primary industrial producer of VOCs—one of two groups of ground-level ozone precursors.[32] VOCs are not only considered ozone precursor pollutants, but they include a number of compounds known to be incredibly toxic and dangerous to human health, including benzene, formaldehyde, xylene, and toluene.[33] Moreover, the industry emits huge amounts of NOx directly from internal combustion engines involved in the transport of materials, water, and hydrocarbons, and indirectly from downstream fossil fuel combustion.[34] Sources of air pollution associated with oil and gas extraction do not directly emit ozone into the atmosphere. Instead, internal combustion engines, drilling, hydraulic fracturing activities, and gas and oil transport infrastructure all release VOC and NOx, which in turn react with sunlight to create ground-level ozone.

In the Permian Basin, oil and gas extraction has pushed VOC and NOx levels to dangerous highs. Based on EPA's most recent National Emissions Inventory data, oil and gas exploration and production activities in the Permian Basin Counties were responsible for 12,793 tons of NOx and 82,442 tons of VOCs in 2017.[35] This makes oil and gas the single largest source of NOx and VOCs in the region. In fact, oil and gas is responsible for twice as much anthropogenic NOx pollution as all mobile sources (e.g., cars, trucks, trains, planes, etc.) and releases more VOCs than all other anthropogenic sources combined. To further put this into

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[32] Exhibit 10, *Controlling Air Pollution from the Oil and Natural Gas Industry*, ENVTL. PROT. AGENCY, https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/basic-information-about-oil-and-natural-gas (last accessed Feb. 14, 2021).

[33] Exhibit 11, *Technical Overview of Volatile Organic Compounds*, Envtl. Prot. Agency, https://www.epa.gov/indoor-air-quality-iaq/technical-overview-volatile-organic-compounds (last accessed Feb. 26, 2021).

[34] Exhibit 12, Allen, D.T., "Emissions from oil and gas operations in the United States and their air quality implications," *Journal of the Air and Waste Management Association*, 66:6, 549-575 (2016), available online at https://www.tandfonline.com/doi/pdf/10.1080/10962247.2016.1171263.

[35] Emissions data queried from EPA's 2017 National Emissions Inventory Data, available online at https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data (last accessed Feb. 26, 2021).

comparison, this is more than eight times the total amount of VOCs released by all anthropogenic sources of air pollution in the City of Denver, Colorado, an urban area with a population of over 700,000, a major international airport, extensive industrial activity, and countless cars and trucks.[36] The table below compares NOx and VOCs from oil and gas with other source categories in Chaves, Eddy, Lea, and Roosevelt Counties.

2017 Emissions by Source Category in Permian Basin Counties[37]

Source	Total NOx (tons/year)	Total VOCs (tons/year)
Non-oil and gas combustion	8,447	1,088
Electricity generating	1,014	33
Mobile source	5,744	2,471
Non-oil and gas industrial processes	259	811
Agriculture	--	638
Gas stations/terminals	--	1,089
Waste disposal	19	48
Solvent use	--	551
Oil and gas	**12,793**	**82,443**

A more recent emissions inventory prepared by the international environmental consulting firm, Ramboll, projects that by 2028, total oil and gas emissions in the region will skyrocket.[38] In total, oil and gas is projected to release more than 26,000 tons of NOx annually, double what was reported in 2017. And by 2028, oil and gas is projected to release more than 112,000 tons of VOCs annually, nearly a 40% increase above what was reported in 2017. The table below details projected 2028 emissions from oil and gas in the region.

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[36] According to EPA's most recent National Emissions Inventory Data, a total of 10,898 tons of VOCs were released from anthropogenic sources of air pollution in 2017.
[37] *Supra* note 34.
[38] *Supra* note 26.

2028 Projected VOC Emissions From Oil and Gas for Permian Basin Counties

County	NOx (tons/year)	VOCs (tons/year)
Chaves	691	3,731
Eddy	11,521	52,748
Lea	14,141	56,060
Roosevelt	120	354
TOTALS	**26,743**	**112,893**

Making matters worse is that these projections are likely to represent significant underestimates of VOC emissions in the region. This is due to the fact that Ramboll presumed oil and gas operators would comply with the 2016 methane rule promulgated by the U.S. Bureau of Land Management and with the EPA's regulations at 40 C.F.R. Part 60, Subparts OOOO and OOOOa, all of which required significant control of VOC emissions from oil and gas operations. However, the Bureau's methane rule was rescinded in 2018. 83 Fed. Reg. 49,184 (Sept. 28, 2018). Further, EPA revised Subparts OOOO and OOOOa in 2020, stripping substantive requirements for oil and gas operators to curtail VOC emissions. 85 Fed. Reg. 57,018 (Sept. 14, 2020). These rollbacks mean current and projected emissions from oil and gas are likely much higher than reported.

That VOC emissions from oil and gas extraction activities in the Permian Basin are likely severely underestimated has been confirmed by recent studies of methane emissions in the region. Methane, which is a potent greenhouse gas, is released together with VOCs at oil and gas production facilities, although in much larger quantities. One study using satellite observations found that overall methane emissions from oil and gas in the Permian Basin of New Mexico and Texas were two times higher than reported by traditional bottom-up inventory estimates.[39] Another study specifically of oil and gas well sites in the Permian Basin of New Mexico found that methane emissions were 5.5-9.0 times greater than EPA National Emissions Inventory estimates for the region.[40] These studies strongly indicate that associated VOC emissions in the Permian Basin Counties are similarly much higher than reported.

Higher methane and VOC emissions are partly the result of industry's widespread practice of venting and flaring gas. In fact, studies have confirmed that New Mexico oil and gas producers vent or flare a significant amount of gas. In 2019, an astonishing 32,897,955 million cubic feet ("Mcf") of gas was vented.[41] Indeed, according to New Mexico Oil Conservation Division data, Energen Resources Corporation—located in Lea County—vented 207,389 Mcf of natural gas in 2019 from just seven wells.[42] In January of 2018, XTO/Bopco, L.P. reported that it vented 171,515 Mcf of natural gas in Eddy County.[43] Incredibly, XTO/Bopco L.P. flared nearly 4.5 million cubic feet of gas in 2019—13% of its total production.[44] And Ameredev, LLC flared fully 78% of its production in 2019.[45]

Compounding the impacts of venting and flaring on air pollution levels, the oil and gas industry reports regular air emission violations from facilities in the Permian Basin. Between

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[39] Exhibit 13, Z. Zhang, R. Gautam, S. Pandey, M. Omara, J.D Maasakkers, P. Sadaverte, D. Lyon, H. Nesser, M.P. Sulprizio, D.J. Varon, R. Zhang, S. Houweling, D. Zavala-Araiza, R.A. Alvarez, A. Lorente, S.P. Hamburg, I. Aben, D.J. Jacob, "Quantifying methane emissions from the largest oil producing basin in the United States from space," *Sci. Adv* . 6, eaaz5120 (2020), available at https://advances.sciencemag.org/content/6/17/eaaz5120.

[40] Exhibit 14, Robertson, A.M., R. Edie, R.A. Field, D. Lyon, R. McVay, M. Omara, D. Zavala-Araiza, and S.M. Murphy, "New Mexico Permian Basin measured well pad methane emissions are a factor of 5-9 times higher than U.S. EPA estimates," *Environ. Sci. Technol.* 2020, 54, 13926-13934.

[41] Exhibit 15, *Flaring in the Oilfield: A Closer Look*, WELC (Aug. 2020), https://westernlaw.org/wp-content/uploads/2020/08/2020.08.05-WELC-NM-Flaring-Report.pdf.

[42] OCD Methane Tracker Dashboard, https://nm-emnrd.maps.arcgis.com/apps/opsdashboard/index.html#/522aee3ad2fb4758863f16269281520d (last accessed Feb. 14, 2021).

[43] Exhibit 16, *Flaring and Venting Data by Operator*, New Mexico Oil Conservation Division, http://www.emnrd.state.nm.us/OCD/documents/C-115Non-TransportedProductDispositionByOperator01282021.xls (last updated Jan. 28, 2021).

[44] *Id.*

[45] *Id.*

December 1, 2019 and December 1, 2020, companies in Eddy and Lea Counties reported 1,454 instances where emissions exceeded legally required limits in permits or regulations.[46] This amounts to an average of nearly four excess emissions events daily in the Permian Basin. These emissions came from refineries, well sites, processing plants, compressor stations, waste disposal facilities, and more. During this time, industry reported more than 313 tons of excess NOx emissions and 2,284 tons of excess VOC emissions.

Modeling studies have, in fact, confirmed that oil and gas production activities contribute to ozone levels at monitors in southeast New Mexico. In a study of ozone in southern New Mexico, modeling confirmed that oil and gas sources of emissions were by far the biggest contributor to ozone at the Carlsbad monitor. In the *Southern New Mexico Ozone Study Technical Support Document* prepared in 2016, researchers reported, "Oil and gas sources make the largest contribution at the Carlsbad monitor, which is the monitor located closest to the Permian Basin."[47] The report further found that "the impact of oil and gas sources increases in 2025 due to projected growth in Permian Basin emissions."[48]

The graphs below, which are excerpted from that report, illustrate the contribution from oil and gas at Carlsbad. Assessing a 2011 base year design value, which was prior to the region experiencing the current level of oil and gas development and experiencing elevated ozone, oil and gas contributed 2 parts per billion (or 0.002 ppm). For that same year's design value, on-road mobile sources, or cars and trucks, contributed only a little more than 0.5 parts per billion at Carlsbad.

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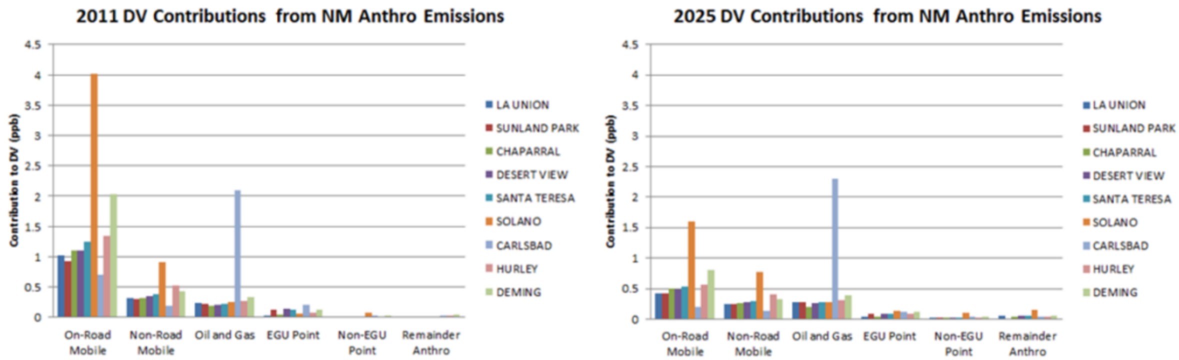
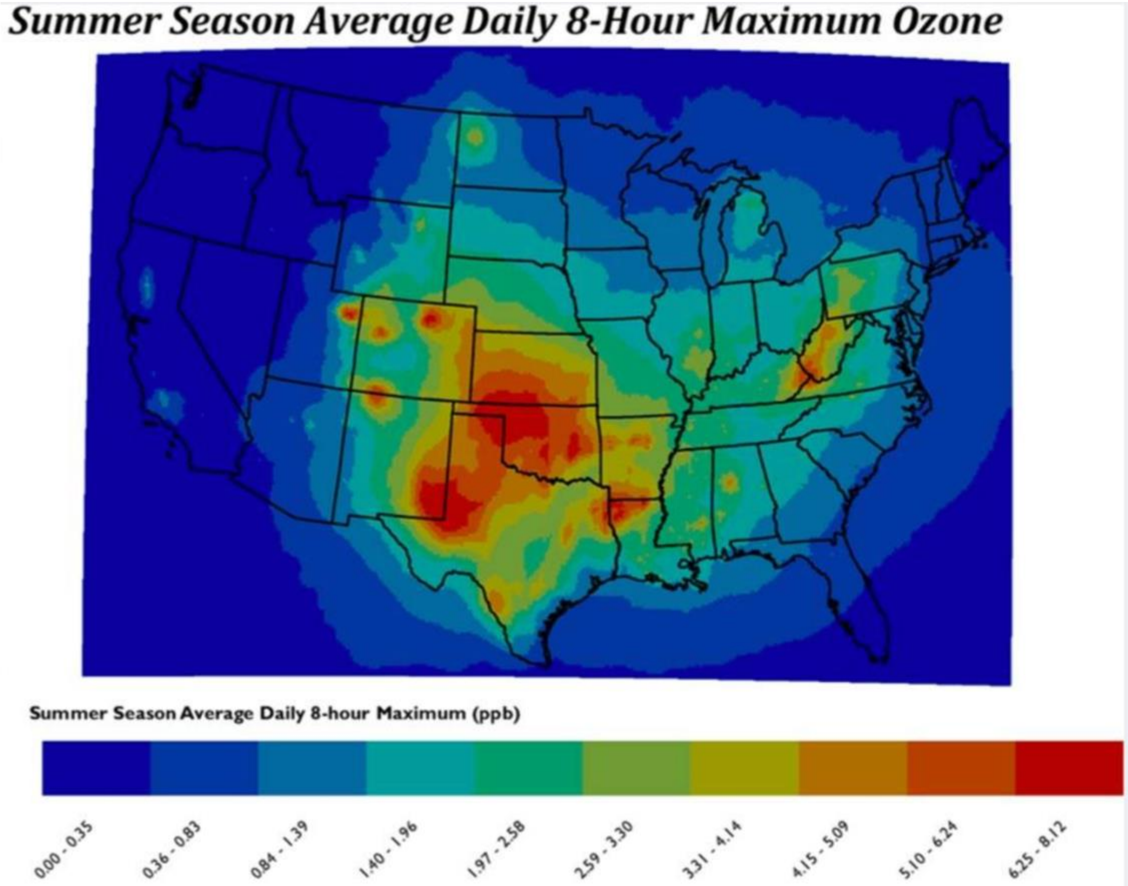
[46] Exhibit 17, Excess Emissions Report 12.1.2019 to 12.1.2020, New Mexico Environment Department, https://www.env.nm.gov/air-quality/excess-emissions-reporting/.
[47] Exhibit 18, Kemball-Cook, S., J. Johnson, A. Wentland, Z. Liu, R. Morris, and Z. Adelman, *Southern New Mexico Ozone Study Technical Support Document* (Oct. 19, 2016) at 70, https://www.wrapair2.org/pdf/SNMOS_TechnicalSupportDocument_19Oct2016.pdf.
[48] *Id*. at 81.



Source-specific contribution to ozone concentrations at southern New Mexico monitors, including Carlsbad.

A 2018 article published in *Environmental Science and Technology*, researchers confirmed the significant impact of oil and gas emissions in the U.S. on ozone concentrations nationwide and disclosed much a more significant contribution.[49] The modeling data revealed the summer season daily average contribution of oil and gas to 8-hour ozone concentrations to be higher than six parts per billion in the Permian Basin of New Mexico. The image below from that article confirms that emissions from oil and gas production have a major impact on southeast New Mexico, underscoring the need for redesignation to nonattainment.

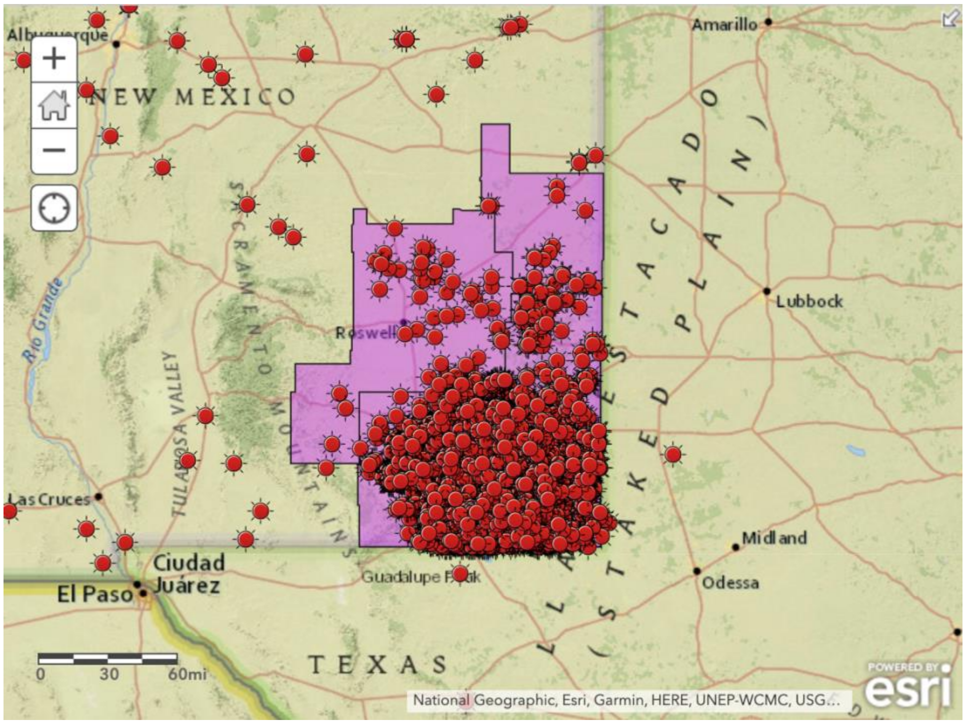
[49] Exhibit 19, Fann, Neal et al. "Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025." *Environmental science & technology* vol. 52,15 (2018): 8095-8103. doi:10.1021/acs.est.8b02050, available online at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6718951/.



Contribution of oil and gas emissions to ground-level ozone concentrations.

D. *<u>Permitting by the New Mexico Environment Department is worsening ozone pollution in the Permian Basin</u>*

Soaring levels of ozone pollution are also being fueled by the NMED's continued rubber-stamping of air pollution permits for new and modified oil and gas facilities in the Permian Basin, seemingly in contravention of the New Mexico SIP. Over the last several years, NMED has approved thousands of permits for new and modified sources of VOC and NOx emissions, even in the face of rising ozone pollution, exceedances, and violations. Most problematic is NMED's reliance on a general permit that allows the oil and gas industry to undergo a streamlined registration process to obtain permit coverage.



Oil and gas facilities permitted by NMED (red dots) in Permian Basin Counties. Facility location data from NMED.

Data from NMED shows that in 2020, more than 400 new source review permits were issued authorizing the construction or modification of stationary sources of air pollution associated with the oil and gas industry in the Permian Basin.[50] In addition, more than 300 general permit registrations were approved in 2020, also authorizing the construction or modification of stationary sources of air pollution associated with the oil and gas industry in the Permian Basin.[51]

A recent report prepared for WildEarth Guardians confirmed that additional new sources of VOC and NOx emissions will undoubtedly contribute to violations of the ozone NAAQS in the region. In his report, Ph.D and engineer Ranajit Sahu found that, based on existing

[50] Exhibit 20, Based on NMED's January 4, 2021 NSR Issuance Report, https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2021/01/AQBP-NSR-Issued-Through-2021.xlsx.
[51] *Id.*

information and analysis, the NMED's permitting of new and modified oil and gas facilities in southeast New Mexico would contribute to violations.[52] Mr. Sahu found:

> [I]n the absence of modeling or analytical data demonstrating otherwise, it is my professional judgment that it is reasonable to presume that any additional emissions of VOCs or NOx in Eddy and Lea counties, such as from the particular facilities at issue in this matter, will contribute to violations of the ozone NAAQS in the area.

Despite confirming the link between permitting new and modified sources of air pollution and the region's ozone pollution, NMED continues to issue permits.

NMED's permitting actions, which have all authorized the release of additional VOC and NOx emissions, have been approved notwithstanding the New Mexico SIP's prohibition on approving permits or general permit registrations for stationary sources that would "cause or contribute" to violations of the NAAQS. *See* 20.2.72.208(D) NMAC. Even though any additional amounts of ozone precursor emissions would necessarily contribute to the Permian Basin's ongoing violations of the ozone NAAQS, NMED has asserted that the agency is not authorized to deny permits or otherwise ensure permits do not lead to emissions that contribute to the ozone problem. This position was unfortunately upheld by a New Mexico citizen board in a 2020 adjudicatory proceeding involving four permitting actions for oil and gas facilities.[53]

NMED's practice of rubber-stamping new VOC and NOx emissions from new or modified stationary source oil and gas facilities underscores the need for the EPA to take action to redesignate the Permian Basin as nonattainment for the 2015 ozone NAAQS.

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[52] Exhibit 21, Expert Report by Ranajit Sahu in support of Petitioner in EIB No. 20-33(A) and EIB No. 20-21(A), available online at https://www.env.nm.gov/environmental-improvement/wp-content/uploads/sites/8/2020/05/2020-08-03-OPF-EIB-20-21A-and-20-33A-WildEarth-Guardians-Notice-to-Present-Testimony-small.pdf.

[53] *See* Exhibit 22, In *the matter of EIB No. 20-21(A) and 20-33(A), Final Order*, https://www.env.nm.gov/environmental-improvement/wp-content/uploads/sites/8/2019/09/Final-Order-EIB-20-21-and-20-33.pdf.

E. <u>Climate change is exacerbating ground-level ozone pollution problems</u>.

The need to designate the Permian Basin of New Mexico is further underscored by the fact that climate change is exacerbating ground-level ozone pollution in the region.

Ozone forms when VOCs and NOx react in the presence of sunlight and heat. VOCs consist of a wide variety of carbon-based compounds, some of which are reactive enough with oxygen to be implicated in the formation ground-level ozone pollution. A partial list of these compounds include formaldehyde, d-Limonene, toluene, acetone, ethanol (ethyl alcohol) 2-propanol (isopropyl alcohol), hexanal. Similarly, NOx are a group of very reactive gases including NO, NO_2, and N_2O. In oil and gas production, NOx is principally produced through the high-temperature combustion of fossil fuel.

Air stagnation plays an important role in ground-level ozone creation, but winds can carry ozone far afield. Because ozone itself is windborne, even rural areas far from oil and gas production are potential targets for unsafe ozone levels. Ozone concentrations typically spike during the summer months when long periods of sunlight and summer heat interact with VOC and NOx. However, climate disruption will continue to raise surface mean temperatures, likely lengthening the period when ground-level ozone is readily formed. EPA itself acknowledges this frightening reality.[54] One recent study predicted heightened levels of ground-level ozone created by climate change could cause a 7.3% increase in emergency room visits related to asthma by children aged 0–17.[55] A 2011 report by the Union of Concerned Scientists surveyed the literature concerning climate change and ground-level ozone and concluded that the "ozone penalty

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[54] *Climate Adaption and Outdoor Air Quality*, EPA, https://www.epa.gov/arc-x/climate-adaptation-and-outdoor-air-quality (last accessed Feb. 14, 2021).
[55] Exhibit 23, Perry E. Sheffield et al., *Modeling of Regional Climate Change Effects on Ground-Level Ozone and Childhood Asthma*, 41 AM. J. PREV. MED. 252 (2011).

factor"—the amount ozone levels are projected to increase for every 1 degree Fahrenheit (ºF) increase in temperature—was 1.2 ppb.[56]

The daily temperature in New Mexico is already 2.7 ºF warmer today than it was in 1970, and estimates indicate that the Southwest could warm from 4 ºF to 10 ºF by 2100.[57] Thus, based solely upon the "ozone penalty factor," global heating alone is likely to result in ground-level ozone levels in the Permian Basin between 4.8 to 12 ppb higher. This increase is separate and apart from the significant increase in ozone pollution levels driven by local and regional emissions of ozone precursors, such as NOx and VOCs. Absent a formal nonattainment designation, climate change will continue to worsen the region's ozone levels, likely preventing Chaves, Eddy, Lea, and Roosevelt Counties from ever achieving compliance with the ozone NAAQS.

IV. EPA has a Legal Duty to Call for the Revision of the New Mexico SIP

The Clean Air Act requires the EPA to call for a state to revise its SIP whenever the agency finds the SIP is substantially inadequate to attain and maintain ozone NAAQS. *See* 42 U.S.C. § 7410(k)(5). Given the available data presented above, there is no question the EPA must require New Mexico to revise its SIP.

A SIP revision is first and foremost called for because all three ozone monitors in the Permian Basin of New Mexico currently have recorded design values in excess of the 2015 ozone NAAQS. The fact that monitors in the region are violating the NAAQS is undeniable

[56] Exhibit 24, *Rising Temperatures, Worsening Ozone Pollution*, UNION OF CONCERNED SCIENTISTS (Aug. 2, 2011), https://www.ucsusa.org/sites/default/files/2019-09/climate-change-and-ozone-pollution.pdf.
[57] Exhibit 25, *Confronting Climate Change in New Mexico*, UNION OF CONCERNED SCIENTISTS (May 2, 2016), https://www.ucsusa.org/resources/confronting-climate-change-new-mexico; Exhibit 26, *Fourth National Climate Assessment, Chapter 25: Southwest*, U.S. Global Change Research Program (2018), https://nca2018.globalchange.gov/chapter/25/.

proof that the New Mexico SIP failing to attain and maintain the NAAQS. Under the Clean Air Act, a SIP must provide for the implementation, maintenance, and enforcement of the NAAQS, and must assure attainment and maintenance of the NAAQS. *See* 42 U.S.C. § 7410(a)(1) and 40 C.F.R. § 51.112(a). If the New Mexico SIP was legally adequate, the Permian Basin would not be violating the 2015 ozone NAAQS.

However, a SIP revision is also necessary in light of the fact that it is clearly failing to ensure that NMED does not permit stationary sources that cause or contribute to violations of the NAAQS.

Under the Clean Air Act, SIPs must set forth "legally enforceable procedures" that enable a state to determine whether the permitting of a new source or modification will interfere with attainment or maintenance of a NAAQS and to prevent the construction or modification of a stationary source that will interfere with attainment or maintenance of the NAAQS. *See* 40 C.F.R. § 51.60(a)(2) and (b)(2).

By NMED's own admissions, the New Mexico SIP neither contains legally enforceable procedures enabling the state to determine whether the permitting of a new source or modification will interfere with attainment or maintenance of the ozone NAAQS nor does it prevent the construction or modification of a source that would interfere with attainment or maintenance of the ozone NAAQS. Even in the Permian Basin, where air quality is in nonattainment of the ozone NAAQS and the permitting of new ozone precursor emissions would contribute to this nonattainment, NMED admits that the New Mexico SIP both prohibits the agency from determining whether a source will interfere with attainment or maintenance and from denying permits.

As the agency asserted in a recent adjudicatory hearing before the New Mexico Environmental Improvement Board, NMED is both unable to gather data necessary to determine whether emissions from a source would cause or contribute to violations of the ozone NAAQS and is legally barred from denying a permit that would interfere with attainment or maintenance of the ozone NAAQS.[58] Officials with NMED's Air Quality Bureau directly and clearly explained the substantial inadequacies in the SIP, including:

- The SIP does not require NMED to evaluate the impacts of permitting new and modified sources to the ozone NAAQS, even where air quality is in nonattainment of the ozone NAAQS. In testimony, NMED's Air Quality Bureau stated:

  > "…the Board's rules do not require the Department to evaluate ozone impacts for individual NSR minor source permit applications."[59]

  The Bureau's witness also testified that 20.2.72.500 NMAC, which is part of the SIP, does not list ozone as an ambient air pollutant that requires evaluation when permitting.[60]

- The SIP exempts minor sources from the Clean Air Act's requirement that NMED both determine whether new or modified sources would interfere with attainment or maintenance of the ozone NAAQS and prevent the construction of new or modified sources that would interfere with attainment or maintenance. In testimony, NMED's Air Quality Bureau explained that "there is no basis for the Department to require further analyses of ozone impacts from [minor] sources," explaining that minor sources are presumed to not have a "significant" impact on ozone concentrations, even in areas currently violating the NAAQS.[61]

- The SIP does not give NMED authority to deny permits that would interfere with attainment or maintenance of the ozone NAAQS. In testimony, NMED's Air Quality Bureau Chief, Elizabeth Bisbey-Kuehn, stated that if they were to deny permits that interfere with attainment or maintenance of the ozone NAAQS, the Department "would be acting outside its authority[.]"[62]

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[58] Exhibit 27, *In the matter of EIB No. 20-21(A) and 20-33(A),* New Mexico Environment Department's Statement of Intent to Present Direct Technical Testimony, https://www.env.nm.gov/environmental-improvement/wp-content/uploads/sites/8/2020/06/2020-09-02-OPF-EIB-20-21A-and-20-33A-NMED-Statement-of-Intent-Rebuttal.pdf.
[59] *Id.* at Exhibit 1 at 8.
[60] *Id*.
[61] *Id*. at Exhibit 1 at 9.
[62] *Id*. at Exhibit 5 at 10.

During this adjudicatory proceeding, these arguments and assertions were not only upheld by counsel for NMED, but ultimately adopted by the New Mexico Environmental Improvement Board. In a Final Order, the Board explicitly stated:

> The Board's regulations and NMED's Modeling Guidelines [] do not require analysis of ozone impacts for minor sources…The Department does not have authority or discretion to deny a permit or require offsets for an individual new or modified minor source in a designated attainment area on the basis that the facility will 'cause or contribute' to ozone levels above the NAAQS.[63]

While New Mexico's SIP very clearly states that NMED must deny permits for new or modified stationary sources that would "cause or contribute" to violations of the NAAQS, according to the reading of NMED and the Environmental Improvement Board, this standard does not apply with regards to the ozone NAAQS. NMED's statements demonstrate the SIP does not require any analysis of ozone impacts, exempts minor sources from review of ozone impacts, and does not authorize the Department to deny permits that would cause or contribute to violations of the NAAQS. Even in the Permian Basin, where the permitting of new or modified sources of ozone precursor emissions would automatically contribute to violations of the ozone NAAQS, NMED and the Environmental Improvement Board interpret the SIP to prohibit denial of permits.

Given this, the New Mexico SIP is substantially inadequate under the Clean Air Act. The SIP clearly fails to provide for the attainment and maintenance of the NAAQS and fails to provide legally enforceable procedures regarding the permitting of stationary sources of air pollution.

Accordingly, EPA must call for New Mexico to submit a revised SIP. *See* 42 U.S.C. § 7410(k)(5). While the Clean Air Act provides an 18-month deadline for a state to submit a

[63] *Supra* note 52 at 16 and 23.

revised SIP, because of the serious public health, welfare, and environmental consequences of ongoing ozone violations in the Permian Basin, we request the EPA call for New Mexico to submit a revision within three months.

V. Conclusion

The Permian Basin of southeast New Mexico is in violation of the 2015 ozone NAAQS, a fact confirmed by EPA design value data and the State of New Mexico. Accordingly, the region, including Chaves, Eddy, Lea, and Roosevelt Counties, must be redesignated from attainment to nonattainment. This redesignation is needed to ensure full protection of public health and welfare, to acknowledge and address environmental injustices committed on New Mexican people of color and underserved communities, and to ensure this dangerous air pollution is cleaned up in a timely and effective manner.

Additionally, it is clear the New Mexico SIP is substantially inadequate to attain and maintain the 2015 ozone NAAQS in the Permian Basin. The fact that the region is in violation of the NAAQS demonstrates the SIP is substantially inadequate. However, NMED and the Environmental Improvement Board read the SIP to disallow the State to deny air pollution permits that would contribute to this violation, further demonstrating the SIP is substantially inadequate.

We request the EPA review and respond to this petition expeditiously. Ongoing violations of the ozone NAAQS in the Permian Basin is only harming peoples' health, degrading the environment, and costing the State of New Mexico dearly. For many, this is a life or death matter. The EPA must act quickly to ensure the State is brought into compliance with the Clean Air Act and compelled to address this festering air pollution. We request the EPA:

1. Provide an immediate acknowledgment that this petition has been received;
2. Notify the Governor of New Mexico, within one month of receipt of this petition, that available information indicates the designation of Chaves, Eddy, Lea, and Roosevelt Counties must be revised from attainment to nonattainment; and
3. Notify the State of New Mexico, within one month of receipt of this petition, that its SIP is substantially inadequate and must be revised within three months of notification.

Again, please direct all correspondence regarding this petition to:

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Thank you for your prompt attention to this significant problem and opportunity to restore clean air, health, and justice to New Mexico.

Submitted this 2nd day of March 2021.

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Jeremy Nichols
Climate and Energy Program Director
WildEarth Guardians

WildEarth Guardians' Spreadsheet Listing Instances During Which New Mexico Air Quality Monitoring Sites Have Recorded Ozone Concentrations in Excess of 95% of the NAAQS in 2021 (as of July 28, 2021)

Date	Source	Site ID	Daily Max 8-hour Ozone Concentration	UNITS	DAILY_AQI_VALUE	Site Name	DAILY_OBS_COUNT	PERCENT_COMPLETE	AQS_PARAMETER_DESC	CBSA_CODE	CBSA_NAME	STATE	COUNTY_CODE	COUNTY
07/09/2021	AirNow	350130021	0.089	ppm	159	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/22/2021	AirNow	350130021	0.088	ppm	156	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/27/2021	AirNow	350130021	0.087	ppm	154	6ZM Desert View	22	92	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/24/2021	AirNow	350250008	0.086	ppm	151	5ZS Hobbs Jefferson	24	100	Ozone	26020	Hobbs, NM	New Mexico	25	Lea
07/09/2021	AirNow	350130022	0.084	ppm	147	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/09/2021	AirNow	350011012	0.084	ppm	147	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
06/09/2021	AirNow	350010029	0.084	ppm	147	SOUTH VALLEY	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/24/2021	AirNow	350151005	0.082	ppm	140	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/22/2021	AirNow	350130020	0.081	ppm	136	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/09/2021	AirNow	350610008	0.081	ppm	136		24	100	Ozone	10740	Albuquerque, NM	New Mexico	61	Valencia
07/21/2021	AirNow	350151005	0.08	ppm	133	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/10/2021	AirNow	350130021	0.08	ppm	133	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/10/2021	AirNow	350130022	0.08	ppm	133	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/09/2021	AirNow	350130008	0.08	ppm	133	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/05/2021	AirNow	350151005	0.08	ppm	133	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/05/2021	AirNow	350150010	0.08	ppm	133		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/22/2021	AirNow	350130008	0.08	ppm	133	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/23/2021	AirNow	350151005	0.078	ppm	126	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/21/2021	AirNow	350130021	0.077	ppm	122	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/21/2021	AirNow	350150010	0.077	ppm	122		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy

07/09/2021	AirNow	350151005	0.077	ppm	122	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/06/2021	AirNow	350130021	0.077	ppm	122	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/18/2021	AirNow	350130021	0.077	ppm	122	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/03/2021	AirNow	350151005	0.077	ppm	122	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/22/2021	AirNow	350151005	0.076	ppm	119	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/22/2021	AirNow	350011012	0.076	ppm	119	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/21/2021	AirNow	350130022	0.076	ppm	119	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/15/2021	AirNow	350151005	0.076	ppm	119	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/09/2021	AirNow	350431001	0.076	ppm	119		24	100	Ozone	10740	Albuquerque, NM	New Mexico	43	Sandoval
07/23/2021	AirNow	350250008	0.075	ppm	115	5ZS Hobbs Jefferson	24	100	Ozone	26020	Hobbs, NM	New Mexico	25	Lea
07/23/2021	AirNow	350150010	0.075	ppm	115		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/10/2021	AirNow	350130008	0.075	ppm	115	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/24/2021	AirNow	350151005	0.075	ppm	115	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/22/2021	AirNow	350011012	0.075	ppm	115	Foothills	14	58	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
06/19/2021	AirNow	350130020	0.075	ppm	115	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/03/2021	AirNow	350130021	0.074	ppm	112	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/09/2021	AirNow	350490021	0.074	ppm	112		24	100	Ozone	42140	Santa Fe, NM	New Mexico	49	Santa Fe
07/25/2021	AirNow	350150010	0.073	ppm	108		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/22/2021	AirNow	350450018	0.073	ppm	108		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/21/2021	AirNow	350450020	0.073	ppm	108	Chaco Culture NHP - Radio Repeater	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/21/2021	AirNow	350450018	0.073	ppm	108		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/17/2021	AirNow	350011012	0.073	ppm	108	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/06/2021	AirNow	350011012	0.073	ppm	108	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo

06/27/2021	AirNow	350151005	0.073	ppm	108	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/10/2021	AirNow	350011012	0.073	ppm	108	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
05/29/2021	AQS	350150010	0.073	ppm	108		17	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/24/2021	AirNow	350011012	0.072	ppm	105	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/23/2021	AirNow	350130021	0.072	ppm	105	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/22/2021	AirNow	350130020	0.072	ppm	105	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/21/2021	AirNow	350451005	0.072	ppm	105	1H Substation	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/21/2021	AirNow	350130008	0.072	ppm	105	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/13/2021	AirNow	350450018	0.072	ppm	105		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/09/2021	AirNow	350130023	0.072	ppm	105	6ZQ Solano	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/18/2021	AirNow	350130008	0.072	ppm	105	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/03/2021	AirNow	350150010	0.072	ppm	105		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
05/06/2021	AQS	350150010	0.072	ppm	105		17	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/27/2021	AirNow	350130022	0.071	ppm	101	6ZN Santa Teresa	22	92	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/25/2021	AirNow	350151005	0.071	ppm	101	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/25/2021	AirNow	350130020	0.071	ppm	101	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/23/2021	AirNow	350130020	0.071	ppm	101	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/23/2021	AirNow	350450020	0.071	ppm	101	Chaco Culture NHP - Radio Repeater	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/22/2021	AirNow	350450020	0.071	ppm	101	Chaco Culture NHP - Radio Repeater	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/22/2021	AirNow	350431001	0.071	ppm	101		24	100	Ozone	10740	Albuquerque, NM	New Mexico	43	Sandoval
07/21/2021	AirNow	350011012	0.071	ppm	101	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/20/2021	AirNow	350150010	0.071	ppm	101		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/12/2021	AirNow	350130022	0.071	ppm	101	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/10/2021	AirNow	350130023	0.071	ppm	101	6ZQ Solano	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/09/2021	AirNow	350130020	0.071	ppm	101	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/09/2021	AirNow	350011012	0.071	ppm	101	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/09/2021	AirNow	350150010	0.071	ppm	101		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/22/2021	AirNow	350130023	0.071	ppm	101	6ZQ Solano	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/20/2021	AirNow	350151005	0.071	ppm	101	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy

06/19/2021	AirNow	350130021	0.071	ppm	101	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/15/2021	AirNow	350011012	0.071	ppm	101	Foothills	20	83	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
06/09/2021	AirNow	350451005	0.071	ppm	101	1H Substation	17	71	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
06/08/2021	AirNow	350011012	0.071	ppm	101	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
05/20/2021	AirNow	350151005	0.071	ppm	101	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/24/2021	AirNow	350450020	0.07	ppm	100	Chaco Culture NHP - Radio Repeater	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/24/2021	AirNow	350150010	0.07	ppm	100		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/22/2021	AirNow	350451005	0.07	ppm	100	1H Substation	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/22/2021	AirNow	350130021	0.07	ppm	100	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/21/2021	AirNow	350130020	0.07	ppm	100	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/08/2021	AirNow	350151005	0.07	ppm	100	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/08/2021	AirNow	350130022	0.07	ppm	100	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/06/2021	AirNow	350130022	0.07	ppm	100	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/25/2021	AirNow	350151005	0.07	ppm	100	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/22/2021	AirNow	350130022	0.07	ppm	100	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/22/2021	AirNow	350010023	0.07	ppm	100	DEL NORTE HIGH SCHOOL	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
05/06/2021	AirNow	350151005	0.07	ppm	100	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/27/2021	AirNow	350130008	0.069	ppm	97	6O La Union	22	92	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/27/2021	AirNow	350130020	0.069	ppm	97	6ZK Chaparral	22	92	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/23/2021	AirNow	350130008	0.069	ppm	97	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/23/2021	AirNow	350011012	0.069	ppm	97	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/22/2021	AirNow	350150010	0.069	ppm	97		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/21/2021	AirNow	350130023	0.069	ppm	97	6ZQ Solano	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/19/2021	AirNow	350450018	0.069	ppm	97		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/16/2021	AirNow	350011012	0.069	ppm	97	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo

07/12/2021	AirNow	350011012	0.069	ppm	97	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/10/2021	AirNow	350011012	0.069	ppm	97	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/08/2021	AirNow	350130021	0.069	ppm	97	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/19/2021	AirNow	350151005	0.069	ppm	97	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/09/2021	AirNow	350450018	0.069	ppm	97		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
05/05/2021	AirNow	350130020	0.069	ppm	97	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
05/05/2021	AirNow	350130021	0.069	ppm	97	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/27/2021	AirNow	350151005	0.068	ppm	93	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	22	92	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/27/2021	AirNow	350150010	0.068	ppm	93		22	92	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/24/2021	AirNow	350010029	0.068	ppm	93	SOUTH VALLEY	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/22/2021	AirNow	350490021	0.068	ppm	93		24	100	Ozone	42140	Santa Fe, NM	New Mexico	49	Santa Fe
07/20/2021	AirNow	350130021	0.068	ppm	93	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/20/2021	AirNow	350450018	0.068	ppm	93		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/13/2021	AirNow	350451005	0.068	ppm	93	1H Substation	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/13/2021	AirNow	350450020	0.068	ppm	93	Chaco Culture NHP - Radio Repeater	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/12/2021	AirNow	350130021	0.068	ppm	93	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/08/2021	AirNow	350011012	0.068	ppm	93	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/06/2021	AirNow	350130008	0.068	ppm	93	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/15/2021	AirNow	350150010	0.068	ppm	93		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/10/2021	AirNow	350010029	0.068	ppm	93	SOUTH VALLEY	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
06/09/2021	AirNow	350390026	0.068	ppm	93	3CRD Coyote Ranger District	21	88	Ozone	21580	Espa¤ola, NM	New Mexico	39	Rio Arriba
06/08/2021	AirNow	350450020	0.068	ppm	93	Chaco Culture NHP - Radio Repeater	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
06/04/2021	AirNow	350151005	0.068	ppm	93	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/01/2021	AirNow	350130021	0.068	ppm	93	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/01/2021	AirNow	350130022	0.068	ppm	93	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/26/2021	AirNow	350011012	0.067	ppm	90	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/24/2021	AirNow	350431001	0.067	ppm	90		24	100	Ozone	10740	Albuquerque, NM	New Mexico	43	Sandoval

07/23/2021	AirNow	350130022	0.067	ppm	90	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/22/2021	AirNow	350130008	0.067	ppm	90	6O La Union	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/22/2021	AirNow	350010029	0.067	ppm	90	SOUTH VALLEY	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/21/2021	AirNow	350250008	0.067	ppm	90	5ZS Hobbs Jefferson	24	100	Ozone	26020	Hobbs, NM	New Mexico	25	Lea
07/21/2021	AirNow	350431001	0.067	ppm	90		24	100	Ozone	10740	Albuquerque, NM	New Mexico	43	Sandoval
07/20/2021	AirNow	350151005	0.067	ppm	90	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/20/2021	AirNow	350130022	0.067	ppm	90	6ZN Santa Teresa	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
07/19/2021	AirNow	350451005	0.067	ppm	90	1H Substation	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/19/2021	AirNow	350450009	0.067	ppm	90	1ZB Bloomfield	24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/19/2021	AirNow	350011012	0.067	ppm	90	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
07/16/2021	AirNow	350450018	0.067	ppm	90		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/12/2021	AirNow	350450018	0.067	ppm	90		24	100	Ozone	22140	Farmington, NM	New Mexico	45	San Juan
07/08/2021	AirNow	350150010	0.067	ppm	90		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
07/04/2021	AirNow	350011012	0.067	ppm	90	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
06/18/2021	AirNow	350151005	0.067	ppm	90	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/18/2021	AirNow	350130020	0.067	ppm	90	6ZK Chaparral	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/12/2021	AirNow	350130021	0.067	ppm	90	6ZM Desert View	24	100	Ozone	29740	Las Cruces, NM	New Mexico	13	Dona Ana
06/12/2021	AirNow	350150010	0.067	ppm	90		24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/10/2021	AirNow	350151005	0.067	ppm	90	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
06/08/2021	AirNow	350431001	0.067	ppm	90		24	100	Ozone	10740	Albuquerque, NM	New Mexico	43	Sandoval
06/04/2021	AirNow	350011012	0.067	ppm	90	Foothills	24	100	Ozone	10740	Albuquerque, NM	New Mexico	1	Bernalillo
06/02/2021	AirNow	350151005	0.067	ppm	90	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy

06/01/2021	AirNow	350151005	0.067	ppm	90	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
05/28/2021	AirNow	350151005	0.067	ppm	90	5ZR ON BLM LAND BORDERING RESIDENTIAL AREA OUTSIDE CARLSBAD CITY LIM	24	100	Ozone	16100	Carlsbad-Artesia, NM	New Mexico	15	Eddy
05/01/2021	AirNow	350250008	0.067	ppm	90	5ZS Hobbs Jefferson	24	100	Ozone	26020	Hobbs, NM	New Mexico	25	Lea

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Modeling of Regional Climate Change Effects on Ground-Level Ozone and Childhood Asthma

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Abstract

Background—The adverse respiratory effects of ground-level ozone are well-established. Ozone is the air pollutant most consistently projected to increase under future climate change.

Purpose—To project future pediatric asthma emergency department visits associated with ground-level ozone changes, comparing 1990s to 2020s.

Methods—This study assessed future numbers of asthma emergency department visits for children aged 0–17 years using (1) baseline New York City metropolitan area emergency department rates, (2) a dose–response relationship between ozone levels and pediatric asthma emergency department visits, and (3) projected daily 8-hour maximum ozone concentrations for the 2020s as simulated by a global-to-regional climate change and atmospheric chemistry model. Sensitivity analyses included population projections and ozone precursor changes. This analysis occurred in 2010.

Results—In this model, climate change could cause an increase in regional summer ozone-related asthma emergency department visits for children aged 0–17 years of 7.3% across the New York City metropolitan region by the 2020s. This effect diminished with inclusion of ozone precursor changes. When population growth is included, the projections of morbidity related to ozone are even larger.

Conclusions—The results of this analysis demonstrate that the use of regional climate and atmospheric chemistry models make possible the projection of local climate change health effects for specific age groups and specific disease outcomes – such as emergency department visits for asthma. Efforts should be made to improve on this type of modeling to inform local and wider-scale climate change mitigation and adaptation policy.

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Introduction

Asthma, the most common chronic disease in seen in pediatrics, is a genetic and environmental disorder.[1, 2] The lungs are exposed to air pollution more than other organ systems particularly for children because of their increased minute ventilation compared to adults. As such, asthma exacerbations may be viewed as the "canary in the coal mine" for children's environmental health. In recent years, public health literature has highlighted respiratory illness as a potential future health impact related to climate change.[3–7] However, projections of such health impacts remain uncommon for regional morbidity projections, such as asthma outcomes.[8] While some studies have modeled regional climate change–related mortality[9, 10] and global morbidity,[11, 12] no models to date have produced regional projections of future pediatric asthma related to climate-driven changes in the U.S.

Climate change through both temperature and wind-pattern changes is projected to affect multiple air-pollutant levels and specifically ground-level ozone (O_3).[13] Ozone is a secondary pollutant formed through photochemical reactions involving other pollutants such as nitrogen oxides (NO_x) and volatile organic chemicals (VOC).[14] Acute ground-level O_3 exposure is linked to childhood respiratory illness,[15] exacerbations of asthma[16] and, more specifically, increased emergency department visits for asthma.[17–21] For example, during the Atlanta Olympics in 1996 when peak daily O_3 dropped 28%, there was an 11% reduction in pediatric emergency department visits for asthma and an over-40% reduction in acute care asthma events not seen with non-asthma acute care events.[17] Asthma emergency department visits are one manifestation of uncontrolled asthma which is associated with both direct (services and medication) and indirect (such as missed work by parents) costs.[22, 23] The objective of this study was to demonstrate one method of projecting climate-driven, ozone-related pediatric asthma effects for the 2020s in an urban area of the U.S.

Methods

Climate change and O_3 modeling

Projections of ground-level O_3 were developed on a 36×36 km grid over the New York City metropolitan area by linking models for global climate, regional climate, and regional air quality.[24–27] Such linkages are necessary to be able to project local future conditions and have been used previously for future health projections.[9, 10] Briefly, global climate was modeled using the Goddard Institute for Space Studies general circulation model. The regional climate model used the Penn State/National Center for Atmospheric Research Mesoscale Model 5. The atmospheric chemistry and O_3 simulations came from the Community Multiscale Air Quality model. The specific greenhouse gas emissions projection came from the A2 scenario of the Intergovernmental Panel on Climate Change (IPCC) Special Report on Emissions Scenarios (*SRES*). The IPCC *SRES* involve future assumptions about energy use; population growth; and political, environmental, and social development and have been used to help standardize climate modeling. The A2 scenario assumes relatively rapid growth in greenhouse gas emissions and population.[28] Knowlton et al (2004)[10] and Hogrefe et al (2004)[24] previously published a description of these models, the greenhouse gas emission scenarios, the O_3 simulations, the model evaluation compared to historic values, and uncertainties within models.

The present study focused on the 14 New York State counties that are considered part of the New York City (NYC) metropolitan area (Appendix A, available online at www.ajpmonline.org). The regional model simulated O_3 for the summer season (June–August) for five consecutive mid-decadal years (e.g., 1993–1997) in the 1990s and 2020s.[24] While the entire period of May – September can have high O_3 levels, this study was restricted, due to computational constraints, to model outputs for June–August. The health effect model used daily 8-hour maximum O_3 concentrations, the same metric specified in the National Ambient Air Quality Standards 2008 revision.[29]

Morbidity analysis—This study used a health-impact assessment framework to assess changes in O_3-related asthma emergency department visits in the population aged 0–17 years in the 2020s compared with the 1990s.

For a typical summer of each decade, county-level impacts were computed as

$$M=(P/10,000)\ ^{*}\ B^{*}\ ERC,$$

where M is the mean number of daily asthma emergency department visits among children aged 0–17 years attributable to daily 8-hour maximum O_3 concentrations; P is the county population in that age group during time period of interest; B is the baseline county-level daily asthma emergency department visit rate among children aged 0–17 years in June–August (per 10,000 population); ERC is the exposure–risk coefficient of asthma morbidity for a given change in the mean O_3 metric, as follows:

$$ERC=exp\,(b\,\Delta O_3)-1,$$

where b is the parameter estimate that reflects a 4% change in asthma emergency department visits per 20 parts per billion (ppb) change in ground-level O_3 (daily 8-hour maximum) derived from Tolbert et al.(2000),[21] and ΔO_3 is the average daily 8-hour maximum O_3 concentration for the time period of interest.

Tolbert et al. (2000)[21] examined associations between air pollutants and emergency department visits for children aged 0–16 years in Atlanta. Ideally, the ERC comes from pooled results that are geographically, diagnostically, and age matched to the study population. However, no such pooled study exists; thus, after considering the relevant epidemiologic literature, this study's ERC was derived from a single study.

The Tolbert et al.[21] study of respiratory emergency department visits and air pollutant associations included multiple ICD-9 diagnostic codes[30] to capture asthma events (asthma (ICD-9 code 493), wheezing (ICD-9 code 786.09) and reactive airway disease (ICD-9 code 519.1, relevant in only 1993 prevalence data) for pediatric emergency department visits among children aged 0–16 years. That study calculated the association of ozone and asthma events with 1-day lag. This study used their relative risk estimate for asthma of 1.04 per 20 ppb increase in daily maximum 8-hour ozone (95% CI, 1.008– 1.073) to calculate the ERC.

Once the mean daily O_3-related morbidity was derived, the summer morbidity was calculated by multiplying by 92 for the number of days in June–August. County populations in the mid-1990s were obtained from 2000 U.S. Census data.[31] Population was held constant in the 2020s for base-case calculations with the intent of isolating the climate influence and reserving exploration of this expected underestimation for the sensitivity analysis described below.

Baseline morbidity rate estimation

This study used publicly available New York State Department of Health asthma emergency department visit data which define an asthma emergency department visit as a primary emergency department diagnosis or an admitting diagnosis from the emergency department of ICD-9 code 493 for any age.[32] Use of this diagnosis in children aged <3 years is problematic due to the difficulty of asthma diagnosis in this age group but more refined population-level data were not available.[33, 34]

Despite these limitations of the state data set, these data were the most appropriate for this model. Average daily summer pediatric asthma emergency department visits for each of the 14 counties were calculated by adjusting the annual age-specific rates with a summer scaling factor. The scaling factor of 0.137 was derived from the proportion of annual asthma emergency department visits that occurred in June–August in New York State.[32] The summer seasonal rate was then converted to a daily rate. For comparison, the average summer scaling value for asthma hospitalizations for children aged 0–4 years in New York State from 1990 to 2004 was calculated to be 0.138.[35] The comparable summer asthma hospitalizations for all ages—including adults— from 2000 to 2005 in New York State was 0.173; these comparisons suggest that the scaling factor used was reasonable.

These scaling calculations were made because the historical daily pediatric emergency department data for these counties (i.e., at a comparable temporal and geographic scale) were not available to these researchers. Baseline morbidity rates were held constant in all analyses. Although morbidity rates will undoubtedly change in the future in response to changes in disease management, access to preventive and chronic disease care and changing demographics (age, race/ethnicity, SES), projection of these shifts was beyond the scope of this study.

Impact assessments—One primary health outcome assessment and two sensitivity analyses were performed. The health outcomes assessment (HOA) used models of future O_3 concentrations to project asthma emergency department visits resulting only from climate change with altered greenhouse gas emissions under the A2 *SRES* scenario. Sensitivity analyses examined alterations in two of the assumptions underlying the primary assessment.

HOA: 2020s climate change only—The objective here was to assess how climate change alone might contribute to changes in summer O_3 concentrations and associated pediatric asthma emergency department visits in the New York region over the next 10–15 years. County population totals were held constant at Census 2000 levels.[31] Similarly, anthropogenic O_3 precursor emissions were held constant consistent with the 1996 county-level U.S. Environmental Protection Agency (EPA) National Emissions Trends inventory. Thus, no projected changes in anthropogenic precursor emissions were applied in the Community Multiscale Air Quality model projections of 2020s summer O_3. The base case did allow for temperature-dependent changes in biogenic and mobile source emissions. No threshold for O_3 impacts was assumed.[36]

Sensitivity analyses

Two sensitivity analyses were conducted to better understand the effects on projections of changing individual modeling assumptions. The first analysis, S1, included the same assumptions of the HOA model but added population growth projections. For S1 in which population was allowed to grow, 2020s populations used the county and age-specific population projections from Cornell University Program on Applied Demographics.[37] This method projected a regional population increase in 2025 compared to 2000 of 3.9% among those aged 0–17 years with a range of negative 14.2% in suburban counties to positive 20% among the urban core counties.

The second analysis, S2, explored the effects of increasing anthropogenic O_3-precursor emissions in addition to climate change. The first step used projections from a separate run of the climate model that included climate change and emissions changes that would be consistent with the A2 *SRES* story line (increases of 29.5% for all anthropogenic NO_x

emission sources and 9% for all anthropogenic VOC emissions). Of note, NO_x and VOC have documented respiratory health effects but this model captures only O_3-related impacts.[38, 39] With this second set of O_3 projections, isolation of the emissions effect was then possible by adding the difference of the two projections from the 2020s to the estimates of O_3 from the 1990s and using those projections to model the health projections. These analyses occurred in 2010.

Results

Health outcomes assessment

County-specific O_3 concentrations and the associated pediatric morbidity projections for emergency department visits for the primary morbidity assessment (HOA) appear in Table 1. Percentage changes in emergency department visits between the 1990s and 2020s for the HOA model appear in Figure 1. The calculations of projections for O_3-related asthma morbidity include the 95% CI from the epidemiologic study of Tolbert et al.[21]. The O_3 projections for average summer daily 8-hour maximum concentrations under the HOA model – which included only climate change - increased their median by 2.7–5.3 ppb across the 14 counties. The distribution of the O_3 changes shows greater increases in those counties outside the urban core toward the coast and along the predominant air mass trajectory from the southwest. As a direct result, the distribution of percentage changes for emergency department visits follows a similar pattern (Figure 1). The underlying population of each county strongly influences the absolute numbers. Median regional O_3-attributable asthma pediatric emergency department visits increased 7.3% in the 2020s compared to the 1990s. This analysis suggests that projected increases in emergency department visits occur both in the surrounding metropolitan counties as well as the urban core.

Sensitivity analyses

The results of the HOA model and the sensitivity analysis outcomes appear in Appendix B (available online at www.ajpmonline.org) which plots the median and 95th percentiles of the percentage change for emergency department visits. Sensitivity analysis S1 shows that population change accounts for the largest contribution to changes in the O_3-attributable emergency department visits. This change is bidirectional as the population of those aged 0–17 years is projected to increase in urban counties – where asthma morbidity is already greatest – but decrease in some suburban counties. Including population growth projections (S1) resulted in a median of 10.6% increase in morbidity.

The second sensitivity analysis S2 isolated the effect of increased anthropogenic O_3-precursor emissions. In the first step of this sensitivity analysis, the O_3 projections from the model run that included both climate change and increased emissions showed a greater range by county but the median increase in asthma emergency department visits was only 6.5%. The isolated emissions effect when climate change effect was removed also showed decreased emergency department visit projections compared to the HOA projections. This result occurred because of decreases in projected O_3 concentrations for most of the urban metropolitan counties in this model, a result of air pollutant interactions that can cause O_3 to decrease in areas where there are higher concentrations of other pollutants such as NO_x.[10] The median O_3-related asthma emergency department visits in the S2 analysis was decreased by 0.4%.

Discussion

The results of this assessment suggest that, compared to the 1990s, by the 2020s climate change could cause a median increase of 7.3% in regional summer O_3-related asthma emergency department visits for children aged 0–17 years across the New York City metropolitan region. However, when examining individual counties, O_3-related emergency department increases ranged from 5.2% to 10.2%. Actual O_3 precursor emissions have been decreasing as opposed to increasing – as detailed by U.S. EPA[40] - and updated precursor emissions assumptions would be useful in future analyses. A sensitivity analysis demonstrated the sometimes counterintuitive effects of air pollution dynamics. As with previous health-impact assessments using these climate models, these O_3 simulations did not account for O_3 precursor emission effects from outside of the modeled region (Eastern U.S.) on future air quality dynamics within the study area.[10, 41]

The assumption of uniform exposure to ozone within each county and the application of a single ERC to children of all ages are two other significant limitations of this study. Other U.S. studies have shown variable associations of O_3 and asthma emergency department visits[18, 42, 43] with a range of RR from 0.98 to 1.06 per 20 ppb increase in daily maximum 8-hour O_3. These studies included a mixture of pediatric and adult patients and used lags ranging from 0 to 3 days. The study by Peel et al.[42] included the same data as Tolbert et al. but included all ages and the association was not significant. Confounding by other air pollutants and choice of lag days are discussed more fully within the original article and subsequent articles published by those same researchers.[21, 42, 44]

In addition, the ERC came from a study in Atlanta, not New York, because of its availability as an age-matched study for asthma emergency department visits. To the extent that air conditioning is more prevalent in Atlanta than in New York (98% versus 85% according to 2003 and 2004 American Housing Survey data),[45] effects of O_3 would likely be lower in Atlanta, since O_3 penetrates indoors only partially in the presence of air conditioning.[46] In this regard, the health-impacts modeling presented here is conservative. However, populations can adapt to climate through behavior changes such as increased time indoors or purchase of air conditioning units. Thus, levels of New York air conditioning use could match those of Atlanta in the future as the climate warms in which case such an ERC is arguably appropriate for projection of future health effects.

In a sensitivity analysis, an examination was made of the additional impact on future morbidity resulting from plausible increases in the exposed population. However, no examination was made of any scenarios of changing baseline morbidity rates, due to the high level of uncertainty regarding such estimates. It should be noted that projected cases scale directly to the baseline rate; thus a reduction by 50% in the baseline for asthma emergency department use would result in a 50% reduction in projected O3-related cases.

Prior modeling exercises similar to this one have mainly used mortality as an outcome; few have addressed morbidity or the unique vulnerabilities of children.[8, 47, 48] Another strength of this particular assessment is the use of county-specific inputs. Other pediatric respiratory effects have been well documented to be associated with O_3 changes such as increased asthma hospitalization,[16] asthma medication use,[49] increased symptoms,[50, 51] and increased missed school days.[52] These additional documented health effects from O_3 as well as a narrow definition for the baseline rates (i.e., excluding diagnoses of wheezing in young children) make these projections inherently conservative regarding the overall burden of disease from O_3. Because the development of the chronic asthma phenotype is a function of both genotype and environmental insults,[2, 53] the future incidence of asthma exacerbations and likely also emergency department visits will change as a function of the changing prevalence of chronic asthma (due in part to increased O_3) as well as the increased rate of O_3-induced exacerbations.

Clearly, this model simplifies complex relationships among change in climate, O_3 precursors, population growth, asthma prevalence, healthcare utilization and the exposure-risk coefficient of O_3 and this specific outcome of asthma. Ethnicity and SES are important risk factors of uncontrolled asthma such is signaled by emergency department visits and are only indirectly included as part of the baseline morbidity estimates.[23] Improvements of these projections would include more geospatially refined and updated data for all of the above as well as different regional population and urbanization growth patterns, more current climate models – as will be used in the 2013 release of the IPCC's 5th Assessment Report, inclusion of bioaerosols such as pollen and other allergens, and additional scenarios beyond the single A2 *SRES* one used in this study.

Given that the projections of this single outcome of asthma emergency department visits are small in absolute number, the costs would not be expected to be staggering. However, given that a single asthma emergency department visits often represents far more uncontrolled asthma cases with associated increase in outpatient visits, medication use and indirect costs such as missed school days for children and work days for parents, the combined costs would be much greater.[16, 22]

Conclusion

These projected effects add an important contribution to current research regarding climate-related disease in children. As the first model of climate-related, regional, pediatric morbidity, this study not only demonstrates an important modeling approach but also provides some quantitative projections to which future work can add and compare. Adaptation measures to climate change that work to reduce ozone levels should be coupled with ongoing efforts for better disease management of asthma. The projections from this study can inform the discussion of local, regional and national policy.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

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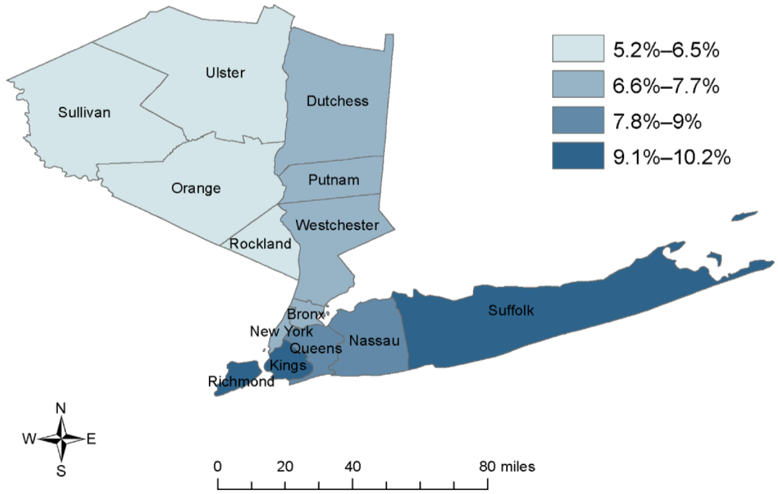


Figure 1.
Percentage change in emergency department visits (2020s A2 vs 1990s baseline) within each of 14 New York state counties of metropolitan NYC modeled under the HOA with A2 *SRES*.
Note: HOA, health outcomes assessment; IPCC SRES, Intergovernmental Panel on Climate Change Special Report on Emissions Scenarios.

Table 1

O_3-related asthma emergency department visit change for children aged 0–17 years in New York City area.

		1990	2020s under A2 IPCC *SRES* climate change scenario			
					(HOA)	
County	O_3 (ppb)[a]	O_3 asthma emergency department visits	O_3 (ppb)	Δ O_3	O_3 asthma emergency department visits	% Δ
Bronx	43.8	188 (111–267)	47.0	3.1	202 (119–288)	7.5
Dutchess	56.1	7 (4–10)	59.9	3.8	8 (5–11)	7.3
Kings	38.5	131 (78–187)	41.9	3.3	143 (85–204)	9.0
Nassau	50.9	32 (19–46)	54.9	4.0	35 (20–50)	8.2
New York	38.5	83 (49–118)	41.2	2.7	89 (53–127)	7.3
Orange	56.3	12 (7–18)	59.6	3.4	13 (8–19)	6.3
Putnam	56.3	1 (1–2)	59.9	3.6	1 (1–2)	6.8
Queens	42.1	93 (55–133)	45.2	3.2	101 (60–143)	7.9
Richmond	37.9	13 (8–18)	41.5	3.6	14 (8–20)	9.8
Rockland	54.2	5 (3–8)	57.4	3.2	6 (3–8)	6.3
Suffolk	54.7	46 (27–66)	60.0	5.3	51 (30–72)	10.2
Sullivan	54.9	2 (1–4)	57.7	2.7	3 (2–4)	5.2
Ulster	54.6	5 (3–7)	57.9	3.3	5 (3–7)	6.4
Westchester	54.1	30 (18–43)	57.8	3.7	33 (19–47)	7.2
Total		648			704	Median 7.3% increase

HOA, Health Outcome Assessment; ppb, part per billion; IPCC SRES, Intergovernmental Pane] on Climate Change Special Report on Emissions Scenarios; O_3, ozone.

[a]Mean summer daily 8-hour maximum O_3 concentration in ppb.

CLIMATE CHANGE
AND YOUR HEALTH

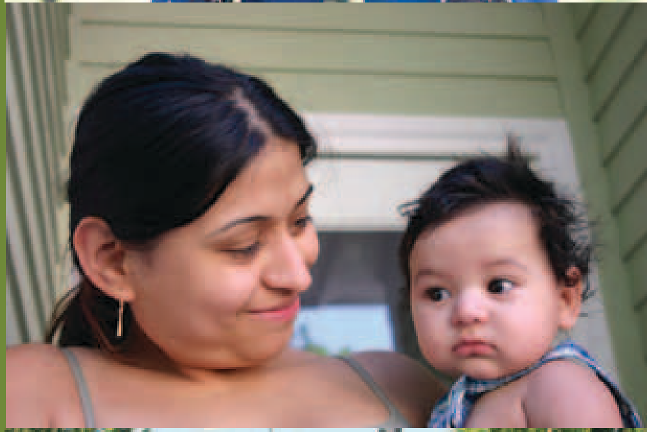
Rising Temperatures, Worsening Ozone Pollution





Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

The Union of Concerned Scientists is a nonprofit partnership of scientists and citizens combining rigorous scientific analysis, innovative policy development, and effective citizen advocacy to achieve practical environmental solutions. Established in 1969, we seek to ensure that all people have clean air, energy, and transportation, as well as food that is produced in a safe and sustainable manner. We strive for a future that is free from the threats of global warming and nuclear war, and a planet that supports a rich diversity of life. Sound science guides our efforts to secure changes in government policy, corporate practices, and consumer choices that will protect and improve the health of our environment globally, nationally, and in communities throughout the United States. In short, UCS seeks a great change in humanity's stewardship of the earth.



CLIMATE CHANGE AND YOUR HEALTH

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Organization affiliations are for identification purposes only. The opinions expressed in this report are the sole responsibility of the authors.

Executive Summary

The quality of life for America's children and their families is adversely affected when ozone pollution increases. Children who miss school because they are experiencing or recovering from an asthma attack may not only fall behind in their studies but also get less exercise and lose time with friends (because they cannot play outside when ozone levels are high). And for every child who goes to the doctor or stays home from school, there is probably a worried parent who is stressed and missing work.

MILLIONS OF AMERICANS SUFFER from the harmful effects of ground-level ozone pollution, which exacerbates lung diseases such as asthma and can cause breathing difficulties even in healthy individuals. The result is more time spent in hospital emergency rooms, as well as additional sick days and even premature deaths. These health impacts not only involve suffering; they are also costly, constituting a significant drag on the U.S. economy. While power plants and cars are among the main sources of ozone-forming pollutants (the chemical precursors to ozone), ozone's formation is dependent on temperature, among other conditions. As a result, climate change has the potential to increase ozone pollution—and its health and economic burdens—across large parts of the country both now and in the future.

This report from the Union of Concerned Scientists combines projections of future climate-induced temperature increases with findings on the relationship between ozone concentrations and temperature to illustrate a potential "climate penalty on ozone."[1] This penalty demonstrates how higher temperatures could increase ozone pollution above current levels, assuming that emissions of ozone-precursor pollutants remain constant.

We analyzed this climate penalty's health consequences expected in 2020 and 2050, including increases in respiratory symptoms, hospital visits for the young and old, lost school days, and premature mortality, for most of the continental United States. We also projected the economic costs of these health impacts in 2020.

Key findings include:[2]

- Just nine years from now, in 2020, we estimate that the continental United States could pay an average of $5.4 billion (2008$) in health impact costs associated with the climate penalty on ozone.
- Higher ground-level ozone concentrations due to rising temperatures in 2020 could lead to an average of 2.8 million more occurrences of acute respiratory symptoms such as asthma attacks, shortness of breath, coughing, wheezing, and chest tightness. In 2050, that could rise to an average of 11.8 million additional occurrences.

- The climate penalty on ozone could lead to an average of 944,000 more missed school days in 2020. In 2050, that could rise to an average of 4.1 million additional missed school days.
- Higher ozone concentrations due to rising temperatures could lead to an average of 3,700 more seniors and 1,400 more infants hospitalized for respiratory-related problems in 2020. In 2050, that could rise to 24,000 more seniors and 5,700 more infants hospitalized.
- Many states and counties that are already struggling to control ozone pollution will have to work even harder to maintain healthy air quality in a warming climate.
- California and states in the Midwest and the Mid-Atlantic could be hit especially hard by the climate penalty on ozone. California may experience the greatest health impacts, with an estimated average of $729 million in 2020 alone.

The findings of this report illustrate yet another reason why we must take action to address climate change without delay—and why our inaction to date will lead directly to real costs within this decade. To make our air cleaner, the U.S. Environmental Protection Agency (EPA) must strengthen its current standards for ozone and ozone-forming pollutants that come from power plants, industry, and vehicles. But in the face of a rapidly warming world, these efforts alone will not be sufficient—we also need new strategies to reduce the pollution that causes climate change.

Climate change has the potential to increase ozone pollution—and its health and economic burdens—across large parts of the country both now and in the future.

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Introduction

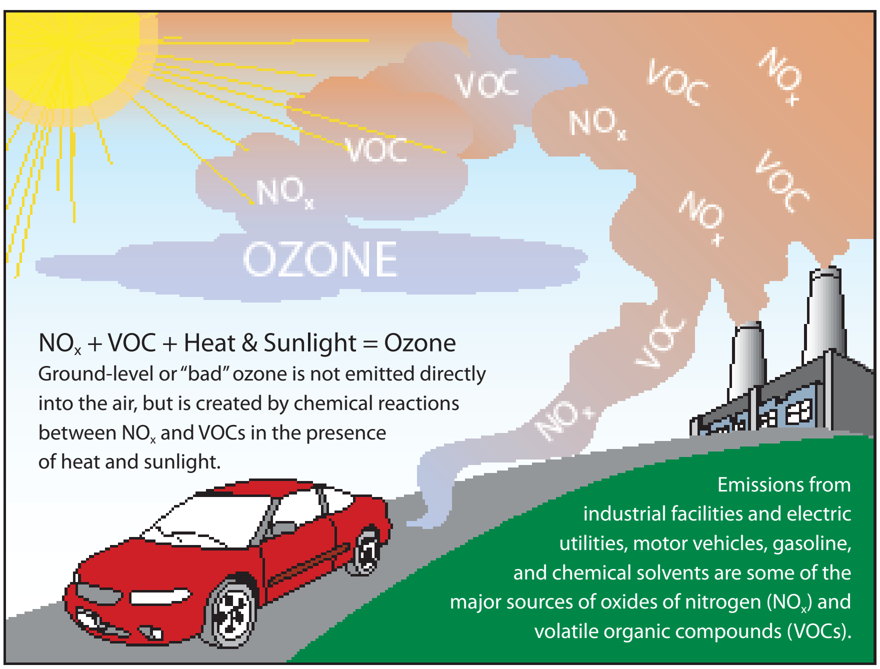
Millions of Americans suffer from the harmful effects of ground-level ozone pollution—be they children too sick to go to school, high school football players not allowed to practice outdoors in the summer, 65-year-olds with lung disease unable to take a walk in the park, or farmers at risk when they harvest their fields. Not only does ozone pollution cause a number of serious breathing problems, and therefore a great deal of suffering, it also is damaging in monetary terms. Whether tallying up the dollars lost to sick days or the high costs of emergency room visits, ozone pollution is expensive.

And now health professionals have an additional ozone pollution concern: climate change. Temperatures in the United States have already risen more than two degrees Fahrenheit (°F) (1.1 degrees Celsius) over the past century, largely because of an excess of heat-trapping gases, especially carbon dioxide, in the atmosphere. Temperatures are likely to keep rising, certainly throughout the next few decades and likely much longer (Karl, Melillo, and Peterson 2009).

Here's the connection: warmer temperatures affect ground-level ozone. Ground-level ozone is formed when a complex set of chemical reactions is triggered by heat and sunlight[3] (Figure 1). That's why we hear warnings of "bad air days" due to ozone pollution most often during the summer and on cloud-free days. Hotter temperatures in a changing climate mean that ozone concentrations are likely to rise over most of the United States (Jacob and Winner 2009 and references therein), possibly offsetting some of the gains we have made in driving down the pollutants that form ozone (Wu et al. 2008).

This report explores how such a phenomenon may occur in many regions of the United States. We model the potential health consequences and costs in 2020 that would be associated with a climate-induced increase in ozone pollution. We also model the health impacts that could occur in 2050.[4] Our results show that as we continue to work to reduce ozone pollution and its health effects in the future, we cannot ignore the consequences of ever-increasing temperatures.

FIGURE 1. Illustration of Ground-Level Ozone Formation



Source: Adapted from EPA 2010.

"Bad" ozone can be distinguished from "good" ozone, which is present at high altitudes in the atmosphere and beneficial because it protects the earth from excessive ultraviolet radiation. But bad, or ground-level, ozone—the primary component of smog—is harmful to health. Human activities such as driving cars and generating electricity are major sources of the ingredients that form smog.[5]

Ozone Pollution and Climate Change—An Unhealthful Mix

When weather forecasters warn about poor air quality or "bad air days" and report an associated color to indicate healthy or unhealthy air (Figure 2), they are usually referring to the level of smog—a hazardous mixture of air pollutants that affect the health and quality of life of children and adults alike.

The Role of Ozone Precursor Pollutants

Ground-level ozone—the primary component of smog—is formed when oxides of nitrogen (NO_x) and volatile organic compounds (VOCs), which are "precursor emissions," chemically react in the presence of heat and sunlight. Some of the major human-made sources of these precursor emissions are power plants, vehicles, and industrial processes.

Reductions in NO_x and VOCs—the primary ingredients in ozone formation—decrease ozone pollution. Thanks in large part to the Clean Air Act, the U.S. Environmental Protection Agency (EPA) reports that a 48 percent decrease nationally in estimated NO_x emissions and a 57 percent decrease in VOC emissions occurred between 1980 and 2009. Average ozone levels have also declined steadily, dropping 30 percent in this same time period (EPA 2011a). The EPA estimates that emissions of NO_x will continue to decline and

FIGURE 2. Air Quality Index Warning System

Air Quality Index	Health Impacts
Good (0–50)	No health impacts are expected when air quality is in this range.
Moderate (51–100)	Unusually sensitive people should consider limiting prolonged outdoor exertion.
Unhealthy for Sensitive Groups (101–150)	The following groups should limit prolonged outdoor exertion: • People with lung disease, such as asthma • Children and older adults • People who are active outdoors
Unhealthy (151–200)	The following groups should avoid prolonged outdoor exertion: • People with lung disease, such as asthma • Children and older adults • People who are active outdoors Everyone else should limit prolonged outdoor exertion.
Very Unhealthy (201–300)	The following groups should avoid all outdoor exertion: • People with lung disease, such as asthma • Children and older adults • People who are active outdoors Everyone else should limit outdoor exertion.

Source: Adapted from EPA 2011.

The Air Quality Index (AQI) is a simple color-coded warning system that alerts the public when air pollutants reach unhealthy levels in a local area. Yellow, for example, means "moderate" air quality conditions and red means "unhealthy" conditions. An AQI value of 100 usually corresponds to the current ozone standard established by the EPA—so as the standard changes, the ozone concentration corresponding to an AQI of 100 will change. Air quality may be reported in a newspaper's weather section or on radio or television, particularly when conditions are problematic. (See the EPA's AIRNow website [*www.airnow.gov*] for daily ozone forecasts and real-time ozone conditions.)

322 state counties across the country (out of the 675 counties monitored) do not meet the current standard for safe levels of ozone, including counties with many of the nation's largest cities. Nearly half of Americans live in areas with "unhealthful" levels of ozone pollution.

could decrease by 26 percent between 2010 and 2020, depending on implementation of reduction standards. Reductions in VOC emissions are expected to essentially level off, declining only 3 percent between 2010 and 2020 (EPA 2011b).

The Importance of Ozone Standards

Further declines in these emissions depend on the EPA's pollution standards becoming stronger in the future and on the continued success of emissions reduction efforts—by the EPA, the states, and others.[6] National averages, however, mask significant local and regional "hot spots" of ozone pollution, especially in urban areas. Cities such as Los Angeles, Baltimore, Washington, DC, Chicago, Boston, Dallas, and Philadelphia are among those that have been designated "out of compliance" with (that is, in non-attainment of) the EPA's current ozone standards.

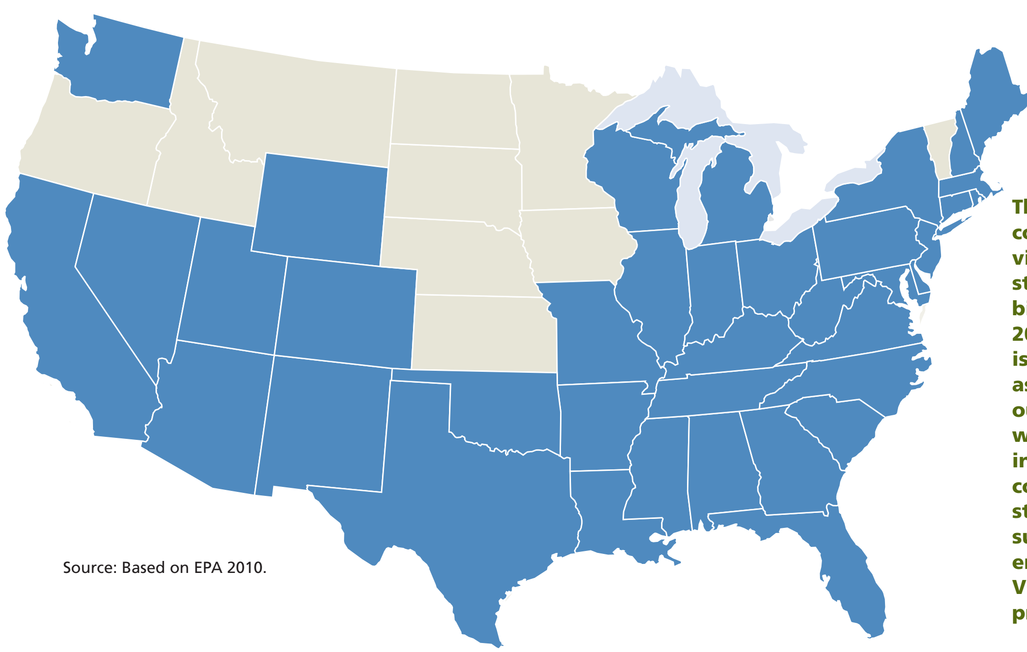
The EPA sets standards for permissible levels of ground-level ozone pollution in terms of its concentration in outdoor air, reported in the units of parts per billion (ppb). The current EPA ozone standard, set in 2008, mandates that summertime ozone concentrations must not show a trend of exceeding 75 ppb (averaged over 8 hours) over a three-year period.[7]

However, the unanimous recommendation of an independent scientific advisory panel convened in 2008 to advise the EPA concluded that the ozone standard should be strengthened to a range of 60 to 70 ppb (Henderson 2008) to protect the health of children, older adults, outdoor workers, and people with asthma and other lung diseases.[8] The current World Health Organization recommendation, for example, is even stronger—at 50 ppb.[9]

The EPA is currently revising its standard in response to court challenges that the agency take into account the latest scientific information on the health impacts of ozone; it is expected that a new rule will be proposed in July 2011.[10]

Meanwhile, 322 counties (out of the 675 counties monitored) in many states across the country do not meet the current standard for safe levels of ozone, as represented in Figure 3. Because these counties include many of the nation's largest cities, nearly half of Americans (48.2 percent) live in areas with "unhealthful" levels of ozone pollution (ALA 2011).[11]

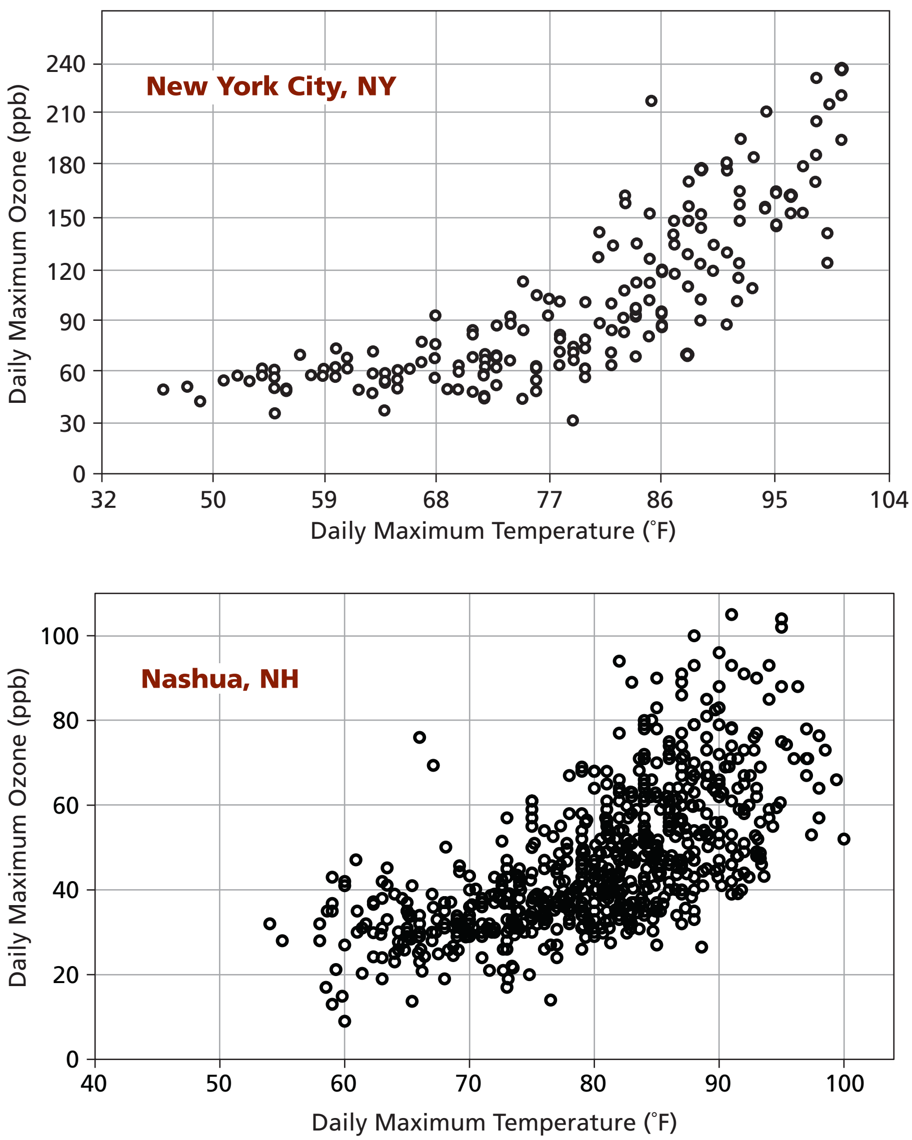
FIGURE 3. **States with Counties that Violate the Current EPA Ozone Standard**



Source: Based on EPA 2010.

The shaded states contain counties that violate the current ozone standard of 75 parts per billion set by the EPA in 2008—a standard that is already recognized as too weak to protect our health. In a warmer world, more counties in additional states could fail to meet the standard, unless they substantially reduce emissions of NO_x and VOCs (the chemical precursors to ozone).

FIGURE 4. Ozone Pollution Worsens as Daily Temperatures Increase



These two graphs show a strong positive correlation between temperature (horizontal axis) and ozone levels (vertical axis) in New York City and Nashua, NH. Based on observed data from New York City for May to October ("smog season," averaging period not specified) for the years 1988 to 1990, and observed data (using a one-hour average) from Nashua, NH, for the years 2005 to 2010, both scatter plots show that the higher the temperature, the higher the ozone level, regardless of a city's size. Climate change is projected to bring higher average temperatures over this century, which could increase the occurrence of elevated ozone concentrations.

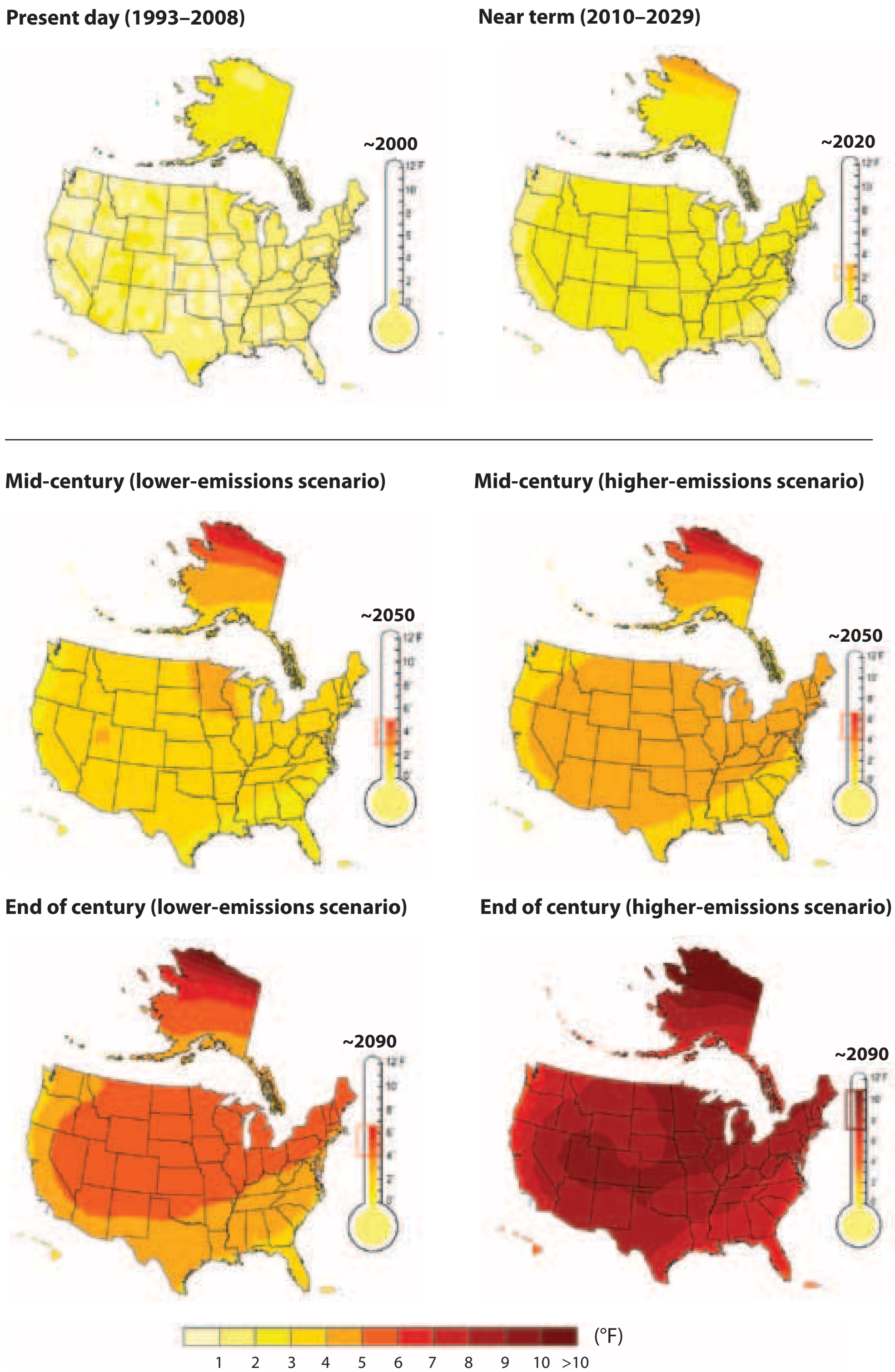
Sources: NAST 2001 (NYC); New Hampshire Department of Environmental Services 2011.

Higher Temperatures Could Make Ozone Pollution Worse

The strong positive relationship between high temperatures and ozone formation is well established (Jacob and Winner 2009). This relationship has been shown both in large cities such as New York City and in smaller cities such as Nashua, NH (Figure 4). In addition to enabling the basic chemical reactions that create ground-level ozone, high temperatures often create stagnant air conditions that cause ozone pollution to settle over an area and remain for a longer time, which in turn increases the potential for human exposure to harmful ozone concentrations (Leibensperger et al. 2008).

Ozone pollution tends to be most severe in urban areas, where vehicular and industrial emissions cluster and where the temperatures are often higher than in surrounding suburbs. However, unhealthful ozone levels can also be found in suburban and rural areas downwind of cities (Logan 1989). Also, precursor emissions from power plants are often carried hundreds of miles over large areas of the country. For example, some pollution from power plants in the Midwest may be transported by prevailing winds to the eastern United States. In addition to harming health, ozone pollution in rural areas negatively affects agriculture and vegetation, such as by decreasing soybean yields (Fishman et al. 2010).

FIGURE 5. Present-Day and Projected Temperature Increases for the United States*



Projected temperature increases for the United States are based on a combination of global climate models. In less than 10 years, largely because of the energy choices the world has already made, much of the country is likely to see temperature increases of an additional 1 to 2°F by 2020—on average about half the increase we have experienced in the last century. However, the emissions choices made today can still make a difference in how much warming we expect to see in future decades, as demonstrated by the difference between the lower- and higher-emissions scenarios at mid-century (2040–2049) and the end of the century (2080–2099).[12]

*All present-day and projected temperature changes are in °F and in reference to a 1961–1979 baseline.

Source: Adapted from Karl, Melillo, and Peterson 2009.

While recent research shows that current ozone standards need to be stronger to protect health, higher temperatures in a warmer world will make the job of maintaining healthy air ever more difficult.

Given the strong dependence of ozone formation on temperature, a changing climate can make ozone pollution worse. As temperatures increase in a warmer world, days that are conducive to ozone formation are likely to be more frequent (see the technical appendix online). Temperatures in the United States have already increased more than 2°F over the past century because of human-caused emissions of carbon dioxide and other heat-trapping gases. The amount of warming we will see later this century depends heavily on the amount of heat-trapping gases we emit today. If the world's emissions rise at the current pace, parts of the United States are projected to warm another 7 to 11°F (3.9 to 6.1°C) by the end of the century (Karl, Melillo, and Peterson 2009). Even if emissions of all heat-trapping gases were to stop immediately, warming would still be "locked in" for years afterward because carbon dioxide resides in the atmosphere a very long time. As such, temperatures will remain elevated for at least the next decade and possibly longer (Armour and Roe 2011; Gillett et al. 2011; Solomon et al. 2009).

What this means is that climate change is likely to complicate the challenge of reducing ozone pollution. Although emissions of ozone-forming pollutants are currently declining, temperature increases associated with climate change are likely to work against this trend. As a result, even to maintain today's ozone levels may require a greater reduction in precursor emissions. Also, there could be a positive-feedback effect; because increasing temperatures would correspond to greater electricity demand for air conditioning during hot summer months, emissions of ozone-forming pollutants from fossil-fuel power plants would probably increase further. States and counties trying to control ozone pollution and its accompanying health problems thus face a challenging situation: while recent research shows that current ozone standards need to be stronger to protect health, higher temperatures in a warmer world will make the job of maintaining healthy air ever more difficult.

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Poor air quality puts large numbers of people at risk for respiratory ailments such as asthma, chronic bronchitis, and emphysema. Today, one in four children in Harlem suffers from asthma (Nicholas et al. 2005). On days with poor air quality, which could increase in a warmer world, both children and adults are more likely to have difficulty breathing, and people with asthma may require a visit to the emergency room.

A Closer Look at Our Methods and Assumptions

Four key steps are involved in this report's analyses of a) the effect that a warmer world could have on ozone pollution and b) the associated health and economic impacts across much of the United States (more detail on all of these steps can be found in the technical appendix online):

1. Deriving a Climate Penalty Factor for the United States

We surveyed the published studies to pick a "climate penalty factor," reviewing both measured data and model projections pertinent to the relationship between temperature and ozone (Bloomer et al. 2009; Jacob and Winner 2008 [and references therein]; Steiner et al. 2006; Taha 2001). Selection of the climate penalty factor was weighted toward a study based on more than two decades of observed data from nearly half of the continental United States (Bloomer et al. 2009). The terms "climate penalty factor" and "climate change penalty," specifically mentioned in some of these published studies, were used to describe the increase in ground-level ozone associated with a given increase in temperature and also the additional reductions in precursor emissions needed to meet a desired ozone level due to the effects of climate change (Bloomer et al. 2009; Wu et al. 2008).

A key simplifying assumption was the choice of a single climate penalty factor—of 1.2 ppb/°F—to apply equally across most of the nation. The current state of research shows that there is regional variation in climate penalty factors—for example, some studies of the Los Angeles Basin show that its urban areas could experience penalty factors greater than 4 ppb/°F (Taha 2001). More research is needed to develop robust regional climate penalty factors that would yield more accurate national numbers. For certain areas, other associated climate consequences (such as changes in vegetation emissions and ventilation processes) could offset the climate penalty (EPA 2009; Wu et al. 2008). Currently, studies are inconclusive as to whether ozone will increase with climate change in the Southeast and coastal Northwest in particular. Therefore we have excluded eight states from our analysis (Florida, Georgia, South Carolina, Alabama, Mississippi, Louisiana, Oregon, and Washington).


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A bad air day in Los Angeles, CA.

We also did not factor into our analysis the fact that some areas of the country (such as California, the Midwest, and the Northeast) could see higher average climate penalty factors, which would mean even greater effects on the health impacts in these places than we report. Finally, we did our modeling using average increases in ozone levels, but in some regions climate change is expected to increase the number of ozone-caused "bad air days" as well as to increase the number of peak pollution episodes more drastically than the average levels (Wu et al. 2008; Bell et al. 2004). This could even further increase the associated health effects beyond what the climate penalty indicates.

2. Estimating Temperature Changes in 2020 and 2050

We used future projections of temperature for two different climate scenarios—a lower-emissions and a higher-emissions scenario, based on information adapted from the U.S. Global Change Research Program (Karl, Melillo, and Peterson 2009)—to determine the most likely range for U.S. average temperature increases in the years 2020 and 2050. The projections for temperature change in the USGCRP report are specified in relation to a 1961 to 1979 baseline, and we scaled them to show changes in temperature relative to the present (Figure 5).[17]

The increases in U.S. average temperatures expected in the two decades centered around 2020 are roughly 1 to 2°F higher than what they are today. The higher-emissions scenario leads to a likely increase of 3 to 5.5°F for the two decades centered around 2050, while a lower-emissions scenario leads to an increase of 2 to 4°F over the same period.

3. Determining the Climate Penalty on Ozone

To derive the climate penalty on ozone (projected future increases in ozone concentrations), we simply multiplied the likely temperature projections from the USGCRP report by the climate penalty factor to determine what levels of increased ground-level ozone could be estimated to occur in the years 2020 and 2050 (Table 1). These calculated values ranged from increases in ground-level ozone of 1 to 2 ppb in 2020 to 2 to 7 ppb in 2050. These values reflected the range in temperatures associated with different future climate scenarios, but they did not account for the ranges of climate penalties found in published studies.

4. Running the BenMAP Model

We analyzed the human health impacts of these increases in ground-level ozone due to the climate penalty for the years 2020 and 2050, utilizing the EPA's BenMAP model; we used the upper and lower ends of the indicated ranges. The model applies information from published epidemiological studies and population projections to estimate the health effects at national, regional, state, and county levels. For our analysis, we focused on national and state data for five categories of impacts: premature mortality, respiratory-related hospital admissions for infants and seniors, asthma-related emergency room visits, occurrences of acute respiratory symptoms (minor restricted-activities days), and lost school days. The model cannot accurately project cost estimates in 2050 because it does not include an income adjustment factor that far out into the future. Also note that BenMAP is not able to directly model air quality; we used monitored air quality data for 2007 that is embedded in the model, and we imposed the climate penalty on top of those measurements.

A major simplifying assumption we made in our analysis was to hold emissions of ozone precursors (such as NO_x and VOCs) constant at 2007 levels and only vary the climate-induced ozone penalty. This followed the convention in the published studies and allowed us to isolate the impact of the climate penalty from other factors affecting ozone pollution. EPA data show that, in fact, U.S. emissions of NO_x and anthropogenic VOCs have been declining over time, driven by provisions of the Clean Air Act, among other factors.[20] These trends are expected to continue, but their relative magnitude depends on the success of EPA regulations.

More details on the BenMAP model and how we used it can be found in the technical appendix online.

This report focuses on national and state data for five categories of health impacts: premature mortality, respiratory-related hospital admissions for infants and seniors, asthma-related emergency room visits, occurrences of acute respiratory symptoms, and lost school days.

While we must limit our heat-trapping emissions in order to lower mid-century temperature increases, temperatures will likely continue to rise for the next decade or two. Therefore, the best near-term option for protecting health is to significantly lower the pollutants that form ground-level ozone.

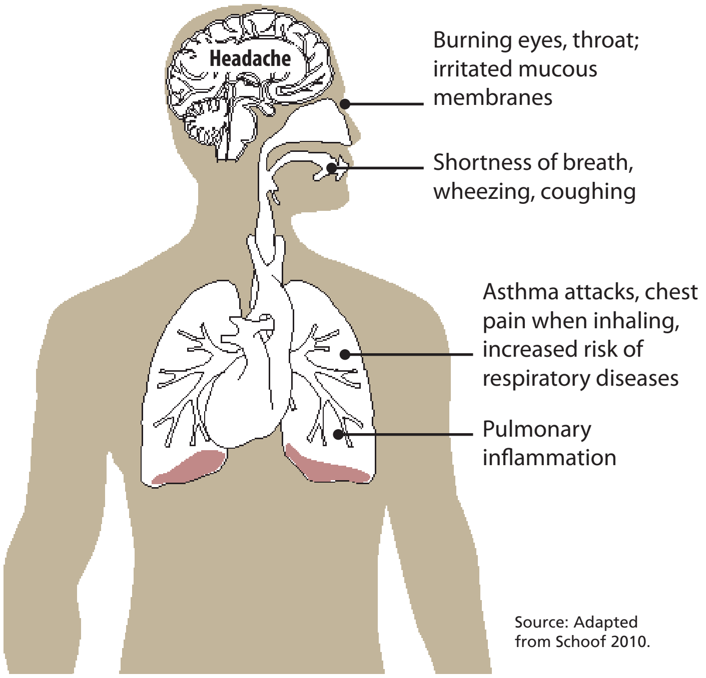
Ozone Is Bad for Your Health

Ground-level ozone, the primary component of smog, irritates the lungs' mucous membranes and other tissues, thereby compromising a person's ability to breathe (Figure 6). Exposure to an increase in ozone concentrations[18] on the order of 10 ppb—beyond an already elevated background level—is associated with increased hospital admissions for pneumonia, asthma, allergic rhinitis, and other respiratory diseases, as well as with premature death. By exacerbating respiratory problems, higher ozone pollution levels send more people to the doctor's office and hospital emergency room and lead to more lost work and school days (Ito, De Leon, and Lippman 2005).

Bearing the Brunt of Ozone Pollution

Ozone is one of the most widespread and dangerous air pollutants. Nearly 37 million children aged 18 and under and more than 17.4 million adults aged 65 and over live in counties with unhealthful ozone levels (ALA 2011). While ozone is bad for nearly everyone, some groups are more susceptible than others.

FIGURE 6. How Ozone Affects the Human Body



Source: Adapted from Schoof 2010.

People who do not suffer from lung conditions often fail to appreciate what they feel like, how dangerous they are, and why the quality of life for the sufferer can be compromised. This is what breathing ozone can feel like if you have a lung condition: you may find it difficult to breathe deeply and vigorously; you may be short of breath and be in pain when taking a deep breath; you may cough, wheeze, and have a chronically sore or scratchy throat; and your asthma attacks may become more frequent. Inside your body, repeated ozone exposures may inflame and damage your lung lining and make the lungs more susceptible to infection.

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Infants and children are particularly vulnerable to air pollution because their lungs are still growing and developing (Committee on Environmental Health 2004). When children's small airways are irritated or swollen, it's simply harder and more painful for them to breathe (Thurston et al.1997). They also have rapid breathing rates, which increases their exposure to inhaled ozone. Parents with young athletes need to be especially aware of bad air days. According to one study, children playing three or more team sports in communities with high daytime ozone concentrations were approximately three times more likely to develop asthma than children playing no sports (McConnell et al. 2002).

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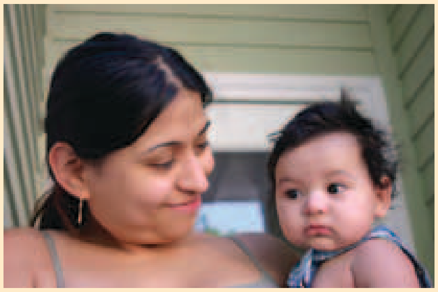
Adults aged 65 years or older are at excess risk of ozone-related hospitalization or death (Delfino, Murphy-Moulton, and Becklake 1998). As the large demographic bulge of the "baby boomers"—estimated at 79 million Americans—moves into this age category over the next two to three decades, air-pollution-related health effects can be expected to substantially increase (Haaga 2002).



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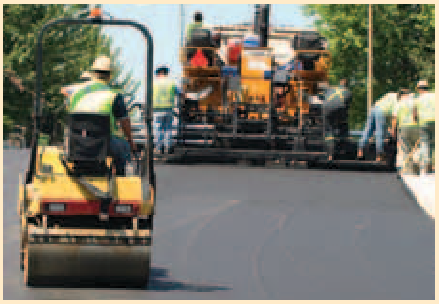
Given their limited access to health-care resources, **low-income and some minority groups** tend to suffer greater impacts when exposed to ozone pollution. Socioeconomic status is an important determinant of differences in asthma prevalence and severity among ethnic minorities in the United States (Forno and Celedon 2009).[19] The large majority of children in this country without any health insurance coverage live in families that fall below the poverty line. Further, very young children, poor children, and children from Spanish-speaking families appear to be at particularly high risk for inadequate asthma therapy—e.g., the use of inhalers (Halterman et al. 2000).



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Outdoor workers such as lifeguards, police officers, construction workers, and farmers are likewise susceptible. One study found that farmers who spend most of the day outside when ozone levels are high suffer reduced lung function that persists for a couple of days (Brauer and Brook 1997). Another study found that healthy and active outdoor workers—lifeguards, in this case—had greater obstruction in their airways when ozone levels were high (Thaller 2008).

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Healthy people also exhibit a small but significant decrease in lung function following a prolonged exposure to ozone levels as low as 60 ppb during mild exercise (Kim et al. 2010).

The Health Conditions Affected by Ozone Pollution

Many Americans who live with chronic respiratory and other diseases are affected by ozone pollution, sometimes fatally. For example:

Asthma. Ozone pollution does not cause asthma, but it exacerbates the condition's effects by causing the patient's lung tissues and airways to become red, swollen, and constricted (Cody et al. 1992). At present some 3.2 million children and more than 9.5 million adults with asthma live in parts of the United States with very high ozone levels in 2011 (ALA 2011). The prevalence of asthma has been increasing since the early 1980s across all age and racial groups and both genders (Pleis et al. 2009). Asthma is the third-ranking cause of hospitalization among children under 15 (DeFrances, Cullen, and Kozak 2007). Asthmatic children using inhalers are vulnerable even to very low levels of ozone—exposure to levels of 50 ppb (33 percent less than the current "safe" level) has been associated with increased shortness of breath and the need for rescue medication (Gent, Triche, and Holford 2003). Expenditures for health and lost productivity related to asthma are estimated to top $20 billion every year (NIH 2009).

Chronic lung disease. Conditions such as chronic obstructive pulmonary disease (COPD)—a long-lasting obstruction of the airways—can be exacerbated by even small increases in elevated ozone levels (e.g., an increment of 10 ppb), with a corresponding effect on public health and health care costs (ALA 2007). COPD includes emphysema, which reduces the ability of the lungs to expel air. A person with emphysema may feel shortness of breath during exertion and, as the disease progresses, even while at rest. COPD also includes chronic bronchitis, which is an inflammation of the bronchial tubes that bring air into the lungs; the condition makes breathing difficult and causes chest congestion and a bad cough. These respiratory diseases are prevalent in the United States. Nearly 4.8 million people with chronic bronchitis and nearly 2.3 million with emphysema live in counties with unhealthful ozone levels (ALA 2011).

Premature death. Because of its serious effects on human health, ozone is also associated with premature deaths, particularly among vulnerable populations and even more particularly among those with respiratory and heart problems. As with chronic lung disease exacerbations, even a small increase in the previous week's average ozone level has substantial effects on death rates. One study, which used data from 95 large U.S. urban communities to estimate a national average of mortality associated with short-term exposure to elevated ozone levels, showed that a small (10 ppb) increase in ozone pollution was associated with a 0.52 percent increase in deaths per day. This study found that an estimated 3,700 deaths annually could be attributed to this small increase in daily ozone levels (Bell et al. 2004).

Analyzing the Impact of Climate Change on Ozone Pollution

OZONE POLLUTION IS PROJECTED to get worse with future warming. But how *much* worse might it be in a world of increasing temperatures? And what would be the implications for the health of our families and our pocketbooks? This report seeks to address these questions by drawing on well-established scientific literature as well as by conducting a new modeling analysis of health impacts and related costs.

Our Approach

This report takes a multidisciplinary approach in evaluating the potentially serious consequences of climate change for ozone pollution and human health in 2020 and 2050. We first surveyed published studies on the relationship between climate (with a specific focus on temperature) and ground-level ozone. From this effort, we chose a single published number that represented the change in ozone pollution per degree rise in temperature (measured in ppb/°F)—a number generally referred to as the "climate penalty factor" (Bloomer 2009). This value, which was consistent both with observational and model studies for a range of nationally averaged estimates (see the technical appendix online), represented changes in ozone pollution from climate alone; ozone precursor emissions were held constant at 2007 levels.

We then used published projections of temperature for two different climate scenarios (a lower-emissions and a higher-emissions scenario) to determine a likely range for increases in temperature in the United States for the years 2020 and 2050. We combined the climate penalty factor with the temperature projections to determine a range for the potential changes in ozone concentration levels—a range called the "climate penalty on ozone"—for the two climate scenarios in both 2020 and 2050.[13]

Finally, we put those increases in ozone concentration into a health model (the Environmental Benefits Mapping model, or BenMAP[14]) that estimates changes in health impacts that arise from changes in ozone pollution. The model can estimate these impacts in terms of incidence (such as the occurrences of acute respiratory symptoms or the number of hospital admissions), as well as in terms of associated costs. (See the box "A Closer Look at Our Methods and Assumptions" for more detailed information.)

Table 1 summarizes how we arrived at the projected increases in ozone pollution that were then used in our modeling analysis.

TABLE 1. Projected Increase in Ozone Concentration Caused by Climate-Induced Temperature Change in 2020 and 2050

Emissions Scenario	Projected Increase in Temperature (°F)	Climate Penalty Factor (ppb/°F)	Projected Increase in Ozone (ppb)
2020 Emissions Scenario[15]	1–2	1.2	1–2 in 2020
2050 Higher-Emissions Scenario[16]	3–5.5	1.2	4–7 in 2050
2050 Lower-Emissions Scenario	2–4	1.2	2–5 in 2050

By multiplying the projected temperature-increase range by the climate penalty factor, we get the range for the projected increases in ozone in 2020 and 2050. For 2050, the temperature increase is highly dependent on whether global warming emissions continue to be released at their current rate or are reduced.

Health and Economic Impacts of the Climate Penalty on Ozone Pollution

We present the overall health impacts of the climate penalty on ozone for 40 states and the District of Columbia (hereafter referred to as "the US-40") for 2020 and 2050. We also present these health impacts in terms of economic costs for the US-40 for 2020. In addition, we present the 10 worst-affected states in 2020 in terms of health and economic impacts. In each case, our results represent an additional impact above what would have occurred without the climate penalty on ozone.

Our results are derived from a 1 ppb and a 2 ppb ozone increase in 2020 and a 2 ppb and a 7 ppb ozone increase in 2050 (Table 1). We note that we are already feeling the impacts of a climate penalty on ozone pollution because of past climate change. Moreover, our results are not cumulative—they represent impacts in the specific year 2020 or 2050. Climate penalties will likely cause increasing ozone pollution, and associated illnesses and costs, in the intervening years.

We modeled the US-40, and not all 50 states, for two reasons. First, the BenMAP model does not include Alaska and Hawaii. Second, for the eight states of Florida, Georgia, South Carolina, Alabama, Mississippi, Louisiana, Oregon, and Washington, the climate penalty may be absent, inconclusive, or a benefit rather than a penalty (see the box "A Closer Look at Our Methods and Assumptions").

The US-40 Climate Penalty and Health

When it comes to our quality of life, the health of our children, and the productivity of our economy, even small amounts of ozone can add up to real consequences. The results presented in this report show that the climate penalty on ozone increases all five health types of impacts examined—occurrences of acute respiratory symptoms, asthma-related emergency room visits, hospital admissions for seniors and infants, lost school days, and premature deaths—both for 2020 and 2050.[21] Millions of people will be affected by these impacts (Tables 2 and 3).

The increases in health impacts in 2050 are substantially larger than 2020 for two reasons: 1) the climate penalty grows with increasing temperatures, and 2) an expanding and aging population puts more people at risk for adverse health effects.

TABLE 2. Health Impacts from the Climate Penalty on Ozone in the US-40 in 2020*

	Lower Case (1 ppb)			Higher Case (2 ppb)		
Category of Health Impact	**Low**	**Central**	**High**	**Low**	**Central**	**High**
Occurrences of Acute Respiratory Symptoms	719,220	1,414,770	2,109,440	1,437,480	2,825,850	4,210,690
Emergency Room Visits, Asthma-Related[22]	1	600	1,100	1	1,200	2,190
Seniors Admitted to Hospital, Respiratory-Related	180	1,840	4,560	350	3,680	9,080
Infants Admitted to Hospital, Respiratory-Related	370	710	1,050	740	1,420	2,090
Lost School Days	211,030	471,530	668,590	422,060	943,560	1,337,160
Premature Deaths	100	260	470	200	510	930

* Numbers are rounded to the nearest 10, except where less than 10. The low and high values represent the 5th and 95th percentiles of the distribution curve. The central value represents the point in the distribution curve with the most likely occurrence. The EPA reports data from the BenMAP model in terms of this most likely or central value, and often includes the 5th and 95th percentiles.

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Parents, coaches, and athletes should all be made aware of a recent study that found that children in communities with high ozone levels who were involved in three or more outdoor sports at the varsity level were three times more likely to develop asthma compared with children playing no sports (McConnell et al 2002).

If temperatures continue on their current upward trajectory, in 2020—just nine years from now—Americans could contend with an average of 2.8 million more occurrences of acute respiratory symptoms such as serious breathing problems, shortness of breath, coughing, wheezing, and chest tightness, possibly leading to restricted activity for the people affected. In 2050 under the higher-emissions scenario, instances of acute respiratory symptoms escalate to an average of 11.8 million.

Seniors and infants are particularly susceptible to being hospitalized for respiratory distress when they are exposed to high levels of ozone, which can also put increased stress on their caregivers and families. In 2020, an average of 3,700 seniors may be hospitalized under the higher ozone scenario; in 2050, this number is likely to climb to an average of 24,000 hospitalizations for seniors. The number of infants likely to be hospitalized averages 1,400 in 2020 and 5,700 in 2050.

In 2020, American children are most likely to miss an average of 944,000 school days linked to increased ozone pollution from the climate penalty. In the year 2050, that number may be as high as 5.8 million additional school days lost.

The US-40 Climate Penalty and Costs

Climate change has already begun to exact economic costs, and they are likely to get bigger both in the near and longer terms. This report highlights one such potential cost of our inaction to reduce global warming emissions. Impacts such as increased occurrences of acute respiratory symptoms and premature deaths not only impose a physical burden, but also take an economic toll. In 2020 alone, a climate penalty on ozone pollution could cost the U.S. public an average of $2.7 billion (1 ppb) to $5.4 billion (2 ppb), as shown in Table 4.[23] For comparison, U.S. federal funding for public health emergency preparedness for events such as natural

TABLE 3. Health Impacts from the Climate Penalty on Ozone in the US-40 in 2050*

	Lower Case (2 ppb)			Higher Case (7 ppb)		
Category of Health Impact	**Low**	**Central**	**High**	**Low**	**Central**	**High**
Occurrences of Acute Respiratory Symptoms	1,729,580	3,400,090	5,066,330	6,033,100	11,822,430	17,560,240
Emergency Room Visits, Asthma-Related	1	1,480	2,710	2	5,190	9,430
Seniors Admitted to Hospital, Respiratory-Related	660	6,850	16,910	2,300	23,940	58,280
Infants Admitted to Hospital, Respiratory-Related	870	1,660	2,440	3,010	5,680	8,290
Lost School Days	528,390	1,181,260	1,674,030	1,849,190	4,145,280	5,858,590
Premature Deaths	290	750	1,360	1,000	2,610	4,740

* Numbers are rounded to the nearest 10, except where less than 10. The low and high values represent the 5th and 95th percentiles of the distribution curve. The central value represents the point in the distribution curve with the most likely occurrence. The EPA reports data from the BenMAP model in terms of this most likely or central value, and often includes the 5th and 95th percentiles.

disasters, pandemics, and acts of bioterrorism was about $1.2 billion in 2010 (Levi et al. 2010).

These potential health costs are estimated here only for the single year of 2020. We cannot present costs for 2050 because the model did not include projections for income growth past 2024. However, it is clear that without action to check climate change, the climate penalty could accumulate year after year and worsen over time. In addition, the larger projected population would mean more people affected; with rising income levels and health care costs, these impacts would likely be more expensive.[24]

Seniors and infants are particularly susceptible to being hospitalized for respiratory distress when they are exposed to high levels of ozone, which can also put increased stress on their caregivers and families.

Although we do not present the economic costs of the five health categories broken out individually here, most of the cost projections are driven by increased premature mortality (see the technical appendix online). However, all of the health effects described in our analysis place a burden on the U.S. economy and health care system. These costs include, for example, the medical expenses of a hospital stay caused by respiratory illness and the loss of income for a sick patient unable to work. As another example, the value of lost school days is derived from the income lost by a parent who has to stay home with his or her sick child. Furthermore, ours is not a comprehensive accounting of all the costs associated with the health impacts of ozone pollution. For example, we did not address the costs associated with pain and suffering.

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The 10 Hardest-Hit States

The health impacts of the climate penalty on ozone will be felt across large areas of the country, but some states and regions are likely to be worse off than others. The greatest consequences are expected for the Midwest, the Mid-Atlantic, and California—all locations with large numbers of residents living in urban areas. Other areas that could face serious impacts include those with the highest number of vulnerable populations such as children and seniors, and those areas with high NO_x and VOC emissions from vehicles and power plants. Given the limited categories of health and cost addressed above, our results most likely underestimate the consequences for those regions of the country (such as portions of California) that are projected to see a higher climate penalty on ozone than the national

TABLE 4. **Health Costs from the Climate Penalty on Ozone in the US-40 in 2020***

	Low	Central	High
Total Costs for a 1 ppb Increase in Ozone Concentration	$443,592,290	$2,712,237,590	$6,864,137,670
Total Costs for a 2 ppb Increase in Ozone Concentration	$886,805,720	$5,423,277,380	$13,724,094,610

* Expressed in 2008$. Numbers are rounded to the nearest 10.

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All the health effects described in this report place a burden on the U.S. economy and health care system. These costs include, for example, the medical expenses of a hospital stay caused by respiratory illness and the loss of income for a sick patient unable to work, or the income lost by a parent who stays home with a sick child.

average. By contrast, some limited areas of the country, such as pockets of the Southeast and Northwest, could see no climate penalty or even a small decrease in ozone concentrations, although the scientific literature on this is inconclusive.

In Table 5, states are ranked according to their estimated number of increased occurrences of acute respiratory symptoms associated with the climate penalty. The results correspond to the higher ozone level in 2020. Health impacts are likely to be greatest in areas with larger exposed populations, so states with large populations or large urban areas are projected to be the most affected.

As shown in Table 6, the 10 states with the highest projected additional health costs from all health impact categories are usually those states with the largest projected populations. Thus California faces the largest costs. However, this trend does not always hold true. Pennsylvania, for example, has fewer projected residents than are projected for Illinois, yet the state is expected to experience higher costs, probably because of demographic factors such as a large number of seniors. Such additional costs come on top of an already substantial burden. California, for example, is already struggling with poor air quality in many counties and the challenges of being out of compliance with the existing air pollution standards (Kleeman et al. 2010).

TABLE 5. State Rankings: Occurrences of Acute Respiratory Symptoms Associated with a Climate Penalty of 2 ppb in 2020*

Rank	State	Population	Low	Central	High
1	California	42,206,743	225,210	442,720	659,680
2	Texas	28,634,896	147,140	289,250	431,000
3	New York	19,576,920	108,150	212,600	316,790
4	Illinois	13,236,720	73,110	143,720	214,160
5	Pennsylvania	12,787,354	67,660	133,010	198,190
6	Ohio	11,644,058	62,530	122,920	183,150
7	Michigan	10,695,993	56,470	111,020	165,420
8	North Carolina	10,709,289	52,350	102,920	153,360
9	New Jersey	9,461,635	51,030	100,320	149,480
10	Virginia	8,917,395	47,250	92,890	138,420

* Occurrences are rounded to the nearest 10. Population projections are courtesy of U.S. Census 2010 and are not rounded.

The results for the other 30 states and the District of Columbia can be found in the technical appendix online.

TABLE 6. **State Rankings: Health Care Costs Associated with a Climate Penalty of 2 ppb in 2020***

Rank	State	Population	Low	Central	High
1	California	42,206,743	$122,327,850	$729,189,390	$1,833,793,410
2	Texas	28,634,896	$79,533,660	$466,321,840	$1,168,692,990
3	New York	19,576,920	$64,435,580	$391,568,950	$989,410,430
4	Pennsylvania	12,787,354	$51,854,220	$331,680,220	$849,044,420
5	Illinois	13,236,720	$43,131,710	$272,348,970	$688,944,830
6	Ohio	11,644,058	$44,397,880	$270,632,840	$688,928,900
7	Michigan	10,695,993	$37,111,390	$230,322,580	$584,559,100
8	North Carolina	10,709,289	$33,827,120	$208,603,060	$528,660,190
9	New Jersey	9,461,635	$32,958,790	$203,089,680	$515,592,450
10	Virginia	8,917,395	$29,436,950	$177,950,320	$449,390,850

* Costs are rounded to the nearest 10. Population projections are courtesy of U.S. Census 2010 and are not rounded.

The results for the other 30 states and the District of Columbia can be found in the technical appendix online.

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Lifeguards at Galveston, TX, beaches provided evidence of the impact of short-term exposure to ozone pollution: researchers found that many lifeguards had greater obstruction in their airways when ozone levels were high. Thanks to this research, Galveston beachgoers are now warned, by an "environmental alert" flag, of air and weather conditions that could pose a health threat (Thaller 2008).

Where Do We Go from Here?

MANY STATES ARE ALREADY struggling with meeting ozone standards, as evidenced by the fact that over 48 percent of Americans currently live in areas with unhealthful ozone levels (ALA 2011: Figure 2). In a warming world, even greater numbers of states could face the health and economic consequences of failing to meet these minimally protective ozone standards. At the very least, the climate-change-induced increase in ozone pollution imposes an additional challenge for the states that currently have areas with unsafe ozone levels: they must work harder to reduce ozone-forming pollutants simply to maintain their current—and often unhealthful—ozone levels.

As states come to grips with this challenge they will need tailored information about how their regional air quality will be affected by future climate change. Further research efforts could include better determination of a) climate penalties for individual regions of the United States and b) future trends in local precursor emissions.

We do not have much time to deal with this challenge. It is already too late to prevent the increase in temperatures driven by climate change over the next decade—and perhaps over the next several decades—given the long residence time of carbon dioxide in the atmosphere. Consequently, the climate penalty for 2020 will also be very difficult to avoid, and the harm

The good news is that both ozone pollution and climate change are fundamentally caused in large part by the same activities: human beings burning fossil fuels to generate electricity and run their vehicles. We can address both ozone pollution and climate change by investing in more fuel-efficient cars, reducing miles driven, and using more renewable energy sources—such as wind, solar, and geothermal—to generate electricity.

to our health and economy associated with this penalty will undermine some of the gains made in reducing ozone-precursor emissions. The EPA's most recent report detailing the benefits and costs of the Clean Air Act shows that it is projected to avoid an estimated 7,100 premature deaths associated with ozone pollution in 2020 (EPA 2011b). But a warmer climate may erode the current ozone-reduction benefits of the Clean Air Act between 3 percent (1 ppb) and 7 percent (2 ppb) in 2020.[25] Although we did not model it, we believe that the best option in the near term is to significantly lower the precursor pollutants that form ground-level ozone so that the health impacts do not escalate further.

In the 2050 time frame, we can do better: we have the choice to significantly lower our heat-trapping emissions from current levels and also make deep cuts in emissions of precursor pollutants. By reducing both kinds of emissions, we can significantly lower the 2050 health impacts due to ozone pollution.

In addition to bad air quality, climate change poses other threats to the health and well-being of Americans. This report addresses just one public health threat associated with climate change, but there are numerous others, including heat waves, elevated allergen levels, more occurrences of waterborne diseases, changing disease vectors, and degraded water quality.

The good news is that both ozone pollution and climate change are fundamentally caused in large part by the same activities: human beings burning fossil fuels to generate electricity and run their vehicles. Therefore we can address both ozone pollution and climate change by implementing practical policies and programs and changing individual behaviors. For example, we can reduce both ozone-precursor and carbon emissions from power plants, refineries, and vehicles by:

- Investing in more fuel-efficient cars and reducing miles driven
- Developing fuels that are less carbon-intensive
- Providing good public transit and other commuting and travel alternatives
- Increasing energy efficiency at industrial and commercial facilities
- Developing and retrofitting homes and buildings to be more efficient
- Using more renewable energy resources—such as wind, solar, and geothermal—to generate electricity
- Ensuring that ozone- and carbon-reduction standards are strong enough to be truly protective of public health
- Working collaboratively with global partners to reduce carbon emissions from other countries.

The United States has the knowledge and the technology to reduce unhealthful pollution while also potentially saving billions of dollars. The choices we make today about the way we live, the energy we use, and the pollution we release will make a difference for the health and well-being of ourselves, our children, and our descendants long into the future. The benefits of cleaning up pollution sources will be a win for climate, a win for air quality, a win for public health, and a win for the economy.

Endnotes

1 Bloomer et al. 2009 examined 21 years of ozone and temperature measurements compiled by the U.S. Environmental Protection Agency's Clean Air Status and Trends Network (CASTNET) from rural areas in the eastern United States. The data showed a correlation between increased temperatures and increased levels of ozone.

2 Key findings are reported using the "central" numbers, from the 2 ppb ozone-increase case in 2020 and the 7 ppb ozone-increase case in 2050, presented in Tables 2, 3, and 4. Health effects modeled included number of acute respiratory symptoms (illnesses), emergency room visits, hospital admissions for infants and seniors, lost school days, and premature death.

3 See *www.epa.gov/air/ozonepollution/basic.html*, accessed on May 11, 2011.

4 The online technical appendix to this report provides a more detailed description of the chemical reactions that form ozone. See *www.ucsusa.org/climateandozonepollution*.

5 This report uses the EPA BenMAP model to calculate these impacts. Background on that model can be found at *www.epa.gov/air/benmap*; for details on our methodology, see this report's technical appendix online.

6 A variety of regulations, including the acid rain program of the Clean Air Act, the Transport Rule, the Mercury and Air Toxics Rule, and light- and heavy-duty vehicle regulations have the beneficial effect of lowering ozone precursors while also tackling other pollution impacts.

7 To assess whether states are meeting the standard, the EPA examines the data collected over a year—data that are reported as averages over each eight-hour period—and then determines the fourth-highest such reading of ozone levels for that year. The agency then averages the readings over three consecutive years. To meet the 2008 EPA ozone standard, that final average cannot exceed 75 ppb.

8 The rule proposed in the Federal Register can be found at *www.epa.gov/air/ozonepollution/fr/20100119.pdf*, accessed on May 11, 2011.

9 The WHO standard for ozone is 100 µg/m^3 (eight-hour mean), which translates to approximately 50 ppb (eight-hour mean). See *whqlibdoc.who.int/hq/2006/WHO_SDE_PHE_OEH_06.02_eng.pdf*, accessed on May 11, 2011.

10 The rule proposed in the Federal Register can be found at *www.epa.gov/air/ozonepollution/fr/20100119.pdf*, accessed on May 11, 2011.

11 "Unhealthful" ozone concentrations range from 76 ppb to 374 ppb (see the American Lung Association air quality chart regarding ozone: online at *www.stateoftheair.org/2011/ key-findings/methodology.html*, accessed on May 11, 2011). The weighted averages were derived by counting the number of days in each unhealthful range (orange, red, purple, and maroon) in each year (2007 to 2009).

12 See Karl, Melillo, and Peterson 2009 for more information on the future temperature projections.

13 The terms climate penalty and climate penalty factor are not original to this document. The terms have previously appeared in Wu et al. 2008 and Bloomer et al. 2009.

14 More information on the BenMAP model can be found at *www.epa.gov/air/benmap*.

15 The near-term (2020) emissions scenario represents the average of the higher- and lower-emissions scenarios. The two scenarios are not appreciably different enough in terms of temperature increases by 2020 to warrant individual analysis of each. The higher scenario is the A2 scenario and the lower scenario is the B1. See IPCC 2000 for more detailed information on the emissions scenarios.

16 The higher scenario is the A2 scenario and the lower scenario is the B1. See IPCC 2000 for more detailed information on the emissions scenarios.

17 The present day is defined as the period 1993 to 2008 in Karl, Melillo, and Peterson 2009.

18 Elevated refers to ozone levels deemed unsafe for exposure (i.e., concentrations above a particular threshold). The EPA has a recommended maximum level of 75 ppb averaged over an eight-hour period.

19 However, ethnic disparities in asthma may also be due to differences among ethnic groups in genetic makeup and gene-environment interaction.

20 See for NO_x: *www.epa.gov/airtrends/nitrogen.html,* accessed on May 11, 2011.

Excerpt: Using a nationwide network of monitoring sites, EPA has developed ambient air quality trends for nitrogen dioxide (NO_2). Trends from 1980–2009 and from 1990–2009 are shown here. Under the Clean Air Act, EPA sets and reviews national air quality standards for NO_2. Air quality monitors measure concentrations of NO_2 throughout the country. EPA, state, tribal, and local agencies use that data to ensure that NO_2 in the air is at levels that protect public health and the environment. Nationally, average NO_2 concentrations have decreased substantially over the years.

See for VOCs: *cfpub.epa.gov/eroe/indexcfm?fuseaction=detail.viewInd&lv=list.listbyalpha&r=219697&subtop=341,* accessed on May 11, 2011.

Excerpt: According to NEI [National Emissions Inventory] data, national total estimated VOC emissions from anthropogenic sources, excluding wildfires and prescribed burns, decreased by 35 percent between 1990 and 2005 (from 23,048,000 to 15,047,000 tons) (Exhibit 2-11, panel A). Trends in estimated anthropogenic VOC emissions in all 10 EPA regions were consistent with the overall decline seen nationally from 1990 to 2005 (Exhibit 2-12). Changes in VOC emissions ranged from a 7-percent reduction (Region 10) to a 54-percent reduction (Region 9).

21 The individual must be treated in a hospital as an inpatient and stay there at least one night. Treatment as an outpatient is not considered hospitalization.

22 The very low 5th-percentile estimates for asthma-related emergency room visits are the result of the weak statistical power of the study used; nevertheless, these estimates still represent actual health impacts.

23 These figures are driven in large part (over 85 percent) by the valuation of premature mortality. The EPA uses a standard metric from the economics literature—the value of a statistical life, or VSL—to calculate these numbers. While VSL is imperfect and has its critics, it is the metric conventionally used in these kinds of economic valuation studies. It is essential to note that this metric should not be misinterpreted as the value of an individual person's life. See the technical appendix online for a fuller explanation.

24 As income rises, the economic value that people attach to health risks increases. Also, the cost of lost work days increases.

25 The number 7,100 and the range of 3 to 7 percent come from EPA 2011b. That report estimates that premature deaths in 2020 could be 710, or 10 percent of 7,100, while the number of deaths avoided would be 93 to 97 percent of 7,100.

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CLIMATE CHANGE AND YOUR HEALTH

Millions of Americans already suffer from the harmful effects of ground-level ozone pollution, which causes a number of serious and costly breathing problems. Now health professionals have an additional air pollution concern: climate change. Because warmer temperatures affect ground-level ozone, climate change will likely cause ozone concentrations to rise over most of the United States.

Climate Change and Your Health: Rising Temperatures, Worsening Ozone Pollution shows how higher temperatures could increase ozone pollution above current levels (assuming that emissions of ozone-precursor pollutants remain constant), and analyzes the resulting expected health consequences of these ozone increases in 2020 and 2050, as well as the economic costs of these health impacts in 2020.

The United States has the knowledge and the technology to reduce unhealthful pollution while also potentially saving billions of dollars. The choices we make today will make a difference for the health and well-being of ourselves, our children, and our descendants long into the future.

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The Union of Concerned Scientists is the leading science-based nonprofit working for a healthy environment and a safer world.

The report and technical appendix are available online (in PDF format) at *www.ucsusa.org/climateandozonepollution.*

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Confronting Climate Change in New Mexico

Action needed today to prepare the state for a hotter, drier future

HIGHLIGHTS

New Mexico's climate is getting hotter and drier, driven by regional and global warming trends. This means earlier springs, hotter summers, and less predictable winters. Precipitation patterns are also changing, with more intense droughts and a greater proportion of precipitation falling as rain rather than snow. Shrunken snowpacks and earlier snowmelts contribute to lower stream flows at critical times of the year when the reduced availability of water has greater economic and environmental consequences. To prepare for the expected impacts of these climate trends, New Mexico would benefit from sustained efforts to mitigate the potential consequences of less water, the health impacts of more excessive heat, and increased losses of lives and property from wildfires, while safeguarding the state's natural resources. Other regions of the world can look to New Mexico's growing leadership on planning for water-resource stress periods and increasing drought-resilient renewable energy sources.

Climate change is altering fundamental weather patterns—affecting temperatures, water availability, and weather extremes—that shape the lives of New Mexicans. As a result, the infrastructure and resource-management plans designed for the conditions of the past may not meet future needs of the farmers, ranchers, outdoor enthusiasts, and other residents of New Mexico.

Already, the resources and systems that New Mexicans depend upon are strained, and further changes in the climate may increase the risks to their homes, their businesses, and their lifestyles.

Developments like these are expected to continue, and likely worsen, as average temperatures rise. While the scarcity of water has long defined the Southwest, the National Climate Assessment has advised that "climate changes pose challenges for an already parched region that is expected to get hotter and, in its southern half, significantly drier" (Garfin et al. 2014).[1]

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Chili peppers are just one of the crops under threat of climate change in New Mexico, as extreme heat and drought cause water supplies to dwindle.

Union of Concerned Scientists

Federal, state, and local governments can do a great deal to protect New Mexicans from current extreme heat, drought, fire, and flooding and to help them plan and prepare for future impacts. State and federal initiatives are already making financial and information resources more available, especially for assessing needs. The next step is to use such resources to design and implement on-the-ground actions that can reduce the risks and make communities more resilient to climate impacts. Strategic investments in long-term projects are also necessary, as is a refocusing of existing programs on planning and resilience. As the people of New Mexico come to understand what they face, they can prepare a prudent response.

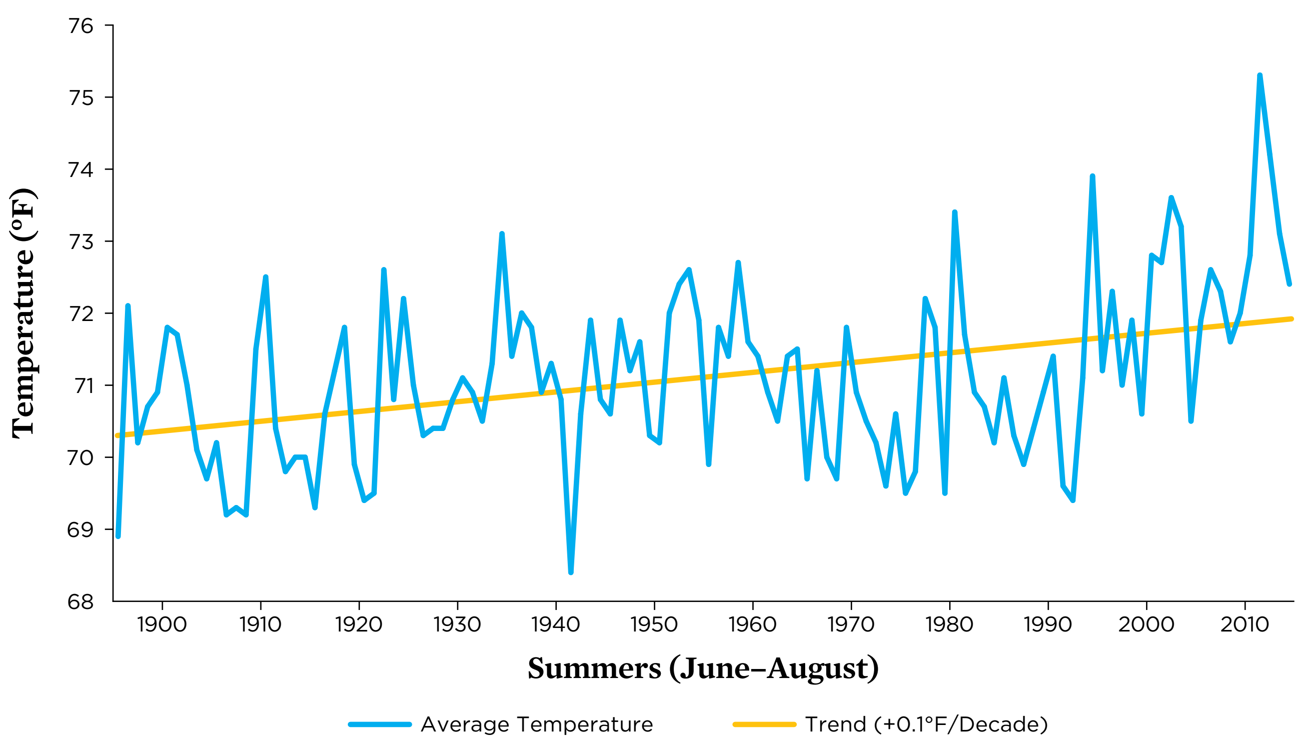
> *"Climate changes pose challenges for an already parched region that is expected to get hotter and, in its southern half, significantly drier."*
>
> — Third National Climate Assessment

Higher Temperatures, More Heat Extremes

In New Mexico, the sixth-fastest-warming state in the nation, the average annual temperature has increased about 0.6°F per decade since 1970 or about 2.7°F over 45 years (Tebaldi et al. 2012). Across the Southwest, the average annual temperature has increased by about 1.5°F, with the decade 2001–2010 being the warmest in over a century (Hoerling et al. 2013).[2] Average annual temperatures in New Mexico are projected to rise another 3.5 to 8.5°F by 2100 (Kunkel et al. 2013).[3]

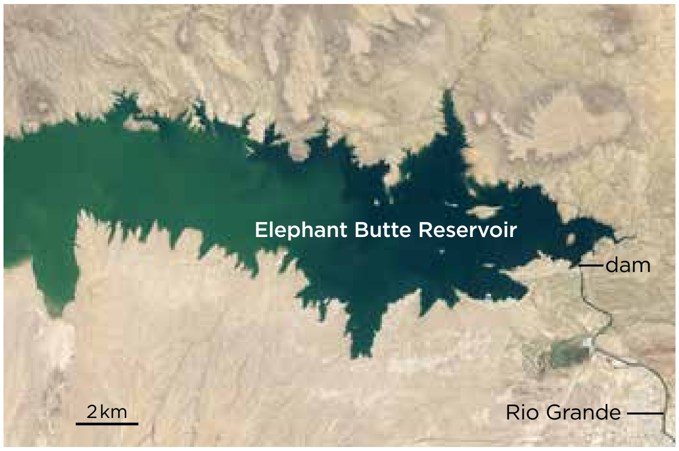
The summer of 2012 was one of the hottest in Albuquerque's history. That year, the city recorded 85 days with temperatures of 90°F or higher (U.S. Climate Data 2012). The following summer, the temperature hit even higher extremes. On June 27,

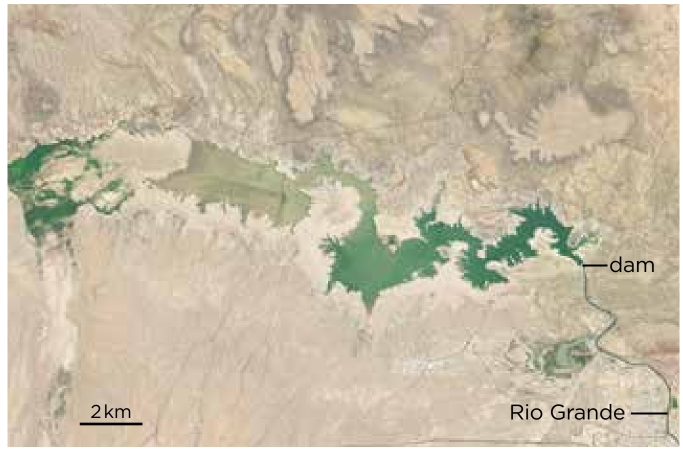
FIGURE 1. Summer Temperatures in New Mexico are Rising



Summer temperatures in New Mexico vary from year to year, but a careful analysis shows a consistent warming trend—a trend that is projected to continue into the future. Since 1970, the trend has steepened to an increase of about 0.6°F per decade.

SOURCE: NOAA 2016.





In 2013, the Elephant Butte Reservoir reached its lowest level in 40 years (right)—just 3 percent of its storage capacity, compared with a nearly full reservoir in 1994 (left). As a result, farmers received less than 10 percent of their typical irrigation water, forcing them to turn to groundwater and other sources.

2013, the city's main airport, Albuquerque International Sunport, recorded a temperature of 105°F, tied for the second-highest on record (Tassy 2013). Sixty miles away and 1,000 feet higher, the temperature at Santa Fe Municipal Airport reached 102°F, the highest ever recorded there (Oswald 2013).

INCREASING TEMPERATURES, SHRINKING WATER RESOURCES

Between 2001 and 2010, the flow in each of the Southwest's major waterways—the Sacramento-San Joaquin river system, the Colorado River, the Rio Grande, and rivers in the Great Basin—was 5 to 37 percent lower than average for the twentieth century (Hoerling et al. 2013). Late-winter and spring snowpacks are projected to decline, and this and the resulting reductions in runoff and soil moisture are expected to make the water supplies for the Southwest's cities, agriculture, and ecosystems even scarcer (Cayan et al. 2010). Droughts, a persistent risk in New Mexico, have broken historical records in recent years, disrupting the state's most vulnerable economic activities. New Mexico entered a severe six-year drought in 2009, by some measures the worst in more than a century, following closely on the heels of an intense drought in the early 2000s (Fleck 2014a). If heat-trapping gases continue to build up in the atmosphere, future droughts are projected to far outstrip those of the past 800 years (Schwalm et al. 2012).

Flow in the Rio Grande, which relates directly to the amount and timing of snowmelt in the mountains north of Albuquerque, is one of the best indicators of drought in New Mexico. For the decade ending in 2010, its flow was 23 percent lower than the twentieth-century average (Hoerling et al. 2013). Every year from 2009 to 2014 was drier than average on New Mexico's portion of the Rio Grande, and the period from 2011 to 2013 was the hottest and driest since recordkeeping began in 1895 (Cart 2013). The Rio Grande and Elephant Butte reservoirs reached historically low levels, reducing allocations of irrigation water for farmers by more than 90 percent and forcing the city of El Paso to depend entirely on groundwater (Voiland 2013). Ranchers have struggled to maintain their herds, and farmers have become increasingly dependent on groundwater resources, adding costs to save their pecan orchards, chiles, and other crops. Smaller communities worry about the viability of their water supplies, fueled by reports like those from Magdalena, the central New Mexican village that made national news when its wells ran dry and residents turned to bottled water (Walsh et al. 2014). Uncertainty in water supplies—ranging from individual wells to acequias (community-managed irrigation canals) to municipal water supplies—are facing ever-increasing demands.

Across the Southwest, the capacity of snow to store water is crucial to managing water, and climate change risks disrupting this vital source of New Mexico's water supply. In 2015, for the fifth year in a row, New Mexico experienced a drought due to diminished snowfall in the mountains (although spring and summer rains offered some relief) (Fleck 2015). In 2014, for the first time in its 40-year history, the San Juan-Chama Drinking Water Project, designed to supplement water resources for Albuquerque, Santa Fe, and other communities in the Rio Grande watershed, was dry (Fleck 2014b).

In the coming decades, climate change will exacerbate the risk of drought in New Mexico in several ways. The National Climate Assessment projects that many parts of the state will see less precipitation overall and more consecutive dry days (Walsh et al. 2014). Even when areas receive rainfall similar to the typical amount they received historically, higher temperatures will increase the water needs for crops and livestock, while also drying out the soil more rapidly.

Gila Forest/Creative Commons (Flickr)

Drought and wildfire decrease the soil's ability to absorb moisture. When New Mexico's heavy rain falls on this affected soil, it runs off instead of seeping down, causing disruptive and dangerous flash floods.

Most important, higher temperatures will reduce snowpack and promote earlier snowmelt in the headwaters of New Mexico's major rivers, resulting in sharply lower levels of available water at critical times of the year (Garfin et al. 2014).

EXTREME PRECIPITATION AND THE LOSS OF SCARCE WATER

New Mexicans are accustomed to extreme rainfall, with much of the state's precipitation generally falling in July and August, associated with the North American monsoon system. However, climate projections across the United States suggest that even as total annual precipitation decreases in places like the Southwest, the heaviest annual rainfall events may become more intense (Walsh et al. 2014). When heavier precipitation falls on drought-hardened or wildfire-transformed soil, which has a reduced ability to absorb moisture, more of the water runs off into streams instead of percolating into the ground (Chief et al. 2008). This can lead to flash floods, as occurred in 2014, when 90 percent of New Mexico experienced extreme or exceptional drought (Crimmins et al. 2014). The monsoon rains, which arrived late that year, dropped an average of three to six inches of rain across the state over just five days in September, with some areas receiving more than 10 inches (NWS ABQ 2015). Albuquerque received nearly half of its expected annual rainfall in a single deluge (*Albuquerque Journal* 2013). As a result, river floods and crests were exceptional in downstream areas. Such extreme events are projected to become more common, forcing communities to prepare for both extreme droughts and extreme floods.

The Impact on New Mexico's Agriculture and Forests

Higher temperatures year round and more frost-free days during winter—especially in an already hot and moisture-stressed region—are projected to increase the stress on plants, making them more vulnerable to agricultural pests and diseases (Frisvold et al. 2013). At the same time, New Mexico forests will continue to be affected by large and intense fires that occur more frequently, potentially overwhelming current and past efforts to manage forests in ways that reduce such risks (Joyce et al. 2014).

INCREASING COSTS TO AGRICULTURE

New Mexico's multibillion dollar agricultural sector already faces the effects of a warming climate. Farmers and ranchers are facing higher costs for less and lower-quality water, particularly in the southern part of the state. As drought conditions persist, farmers who historically have relied on water allocations from reservoirs and streams to irrigate their crops are pumping more and more groundwater to make up the deficit. Deeper and deeper wells are needed to accommodate the falling water table, and often the water contains higher levels of salt and other minerals that damage crops and contaminate the soil (Frisvold et al. 2013).

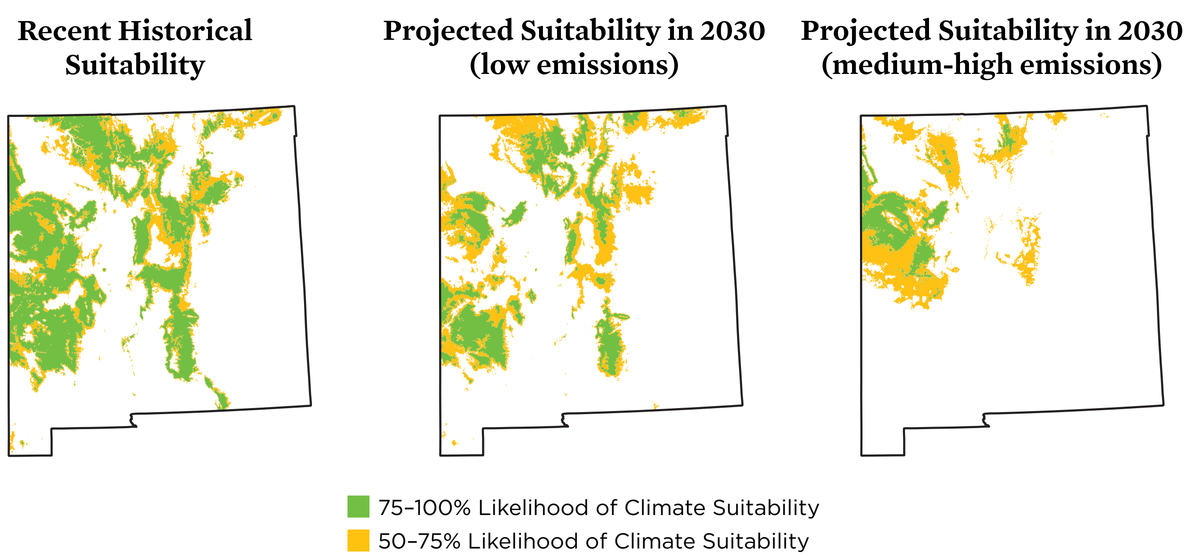
In 2013, Rio Grande farmers received allotments of only 3.5 inches of water per acre, compared with a full allotment of 36 inches in normal years (New Mexico Water Dialogue 2013). This meant they received just a tiny fraction of the 4 to 5 acre-feet needed between planting and harvest (Bosland and Walker 2004). At the same time, ranchers significantly reduced their herd sizes or sold off cattle to give grasslands a chance to recover from extreme drought (Uyttebrouck 2013).

FORESTS

In recent years, drought, insects, and wildfires have ravaged New Mexico forests at a scale not seen in living memory (Funk et al. 2014). The piñon pine, New Mexico's state tree, is important both ecologically and culturally. Few other tree species can survive in the semiarid areas where they are most common, yet the effects of climate change are placing its future persistence in the state at risk (Adams et al. 2009). In the early 2000s, severe heat and drought and bark-beetle infestations caused a massive die-off of piñons. Mortality among mature piñons in the middle Rio Grande Basin exceeded 90 percent (Breshears et al. 2005). As many as 350 million piñons died across the West, with the greatest mortality in the northern New Mexico foothills of the southern Rocky Mountains (Meddens, Hicke, and Ferguson 2012). While mature pine trees live hundreds of years and have experienced severe drought before, this drought was associated with much hotter temperatures than those in the past, in large part due to a changing climate (Adams et al. 2009). The U.S. Forest Service projects that piñons could disappear from much of their current range by 2030—threatening to disrupt the entire forest ecosystem—even if the rise in heat-trapping emissions slows (Rehfeldt et al. 2012).

Hotter, drier conditions lead to more frequent and more destructive wildfires, while earlier snowmelt means that forests are drier for a longer spring season, before monsoon rains moisten the surface. The fire season in New Mexico has lengthened substantially over the past 40 years—from

FIGURE 2. Climate Change is Diminishing the Habitat of Piñon Pines



The degree of climate change will affect the amount of western land suitable for piñon pines in 2030. These maps depict areas modeled to be climatically suitable for the tree species under the recent historical (1961–1990) climate (left), conditions projected for 2030 given lower levels of heat-trapping emissions (center), and conditions projected for 2030 given medium-high levels of emissions (right). Areas in yellow have a 50–75 percent likelihood of being climatically suitable according to the models; areas in green have more than a 75 percent likelihood. These models do not address other factors that affect where species occur, such as soil types.

NOTE: The two future emissions levels are the B1 and A2 scenarios of the Intergovernmental Panel on Climate Change, respectively.

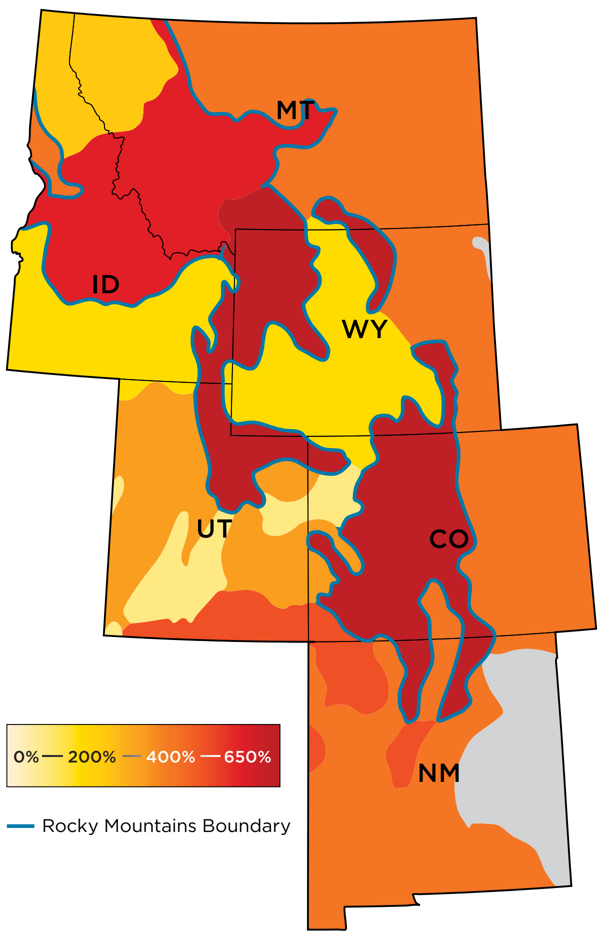
SOURCES: BASED ON USFS MOSCOW LAB 2014.

five months to seven—and fires of more than 1,000 acres occur twice as often (Climate Central 2012; Westerling et al. 2006). Wildfires themselves are a significant source of heat-trapping gases in the atmosphere.

As the Southwest continues to warm, the burn area across the region is projected to rise dramatically. The regions hit hardest are likely see a six-fold increase or more in average area burned each year (see Figure 3).

Two of the largest wildfires in New Mexico's recorded history occurred in 2011 and 2012. In 2011, more than one million acres burned as 1,875 fires raged across the state (NICC 2011). The Las Conchas Fire, then the largest in the history of New Mexico, burned over 156,000 acres (NICC 2011). Damage occurred in parts of Los Alamos National Laboratory, the Santa Clara Pueblo, and affected the water supplies for Santa Fe

FIGURE 3. Rise in Global Temperature Will Lead to Increased Wildfires in New Mexico

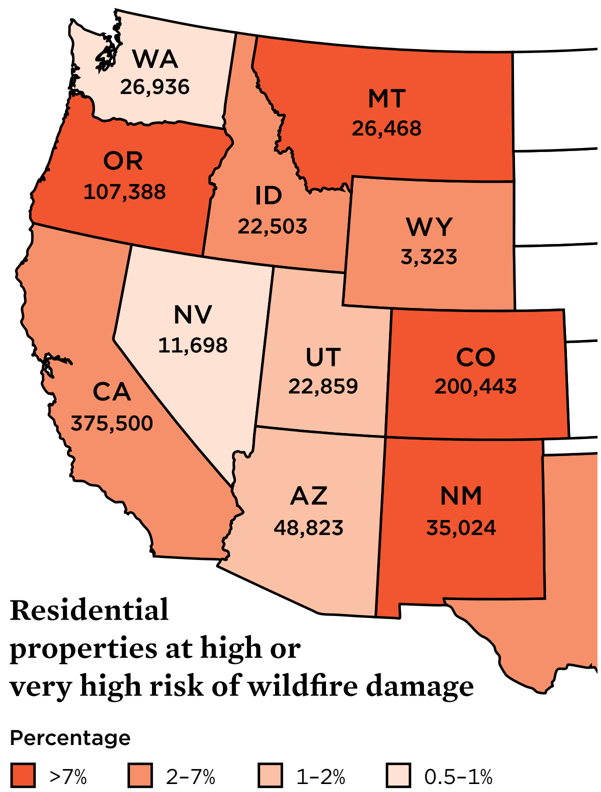


Scientists project that a temperature increase of just 1.8°F will lead to marked increases in acreage burned by wildfires in the western United States, including New Mexico. This figure shows the projected percentage increase in burned area, compared with the 1950–2003 average. Much of New Mexico is expected to see a 400% increase in burned areas, with parts of the Rocky Mountains headed towards a 650% increase.

NOTE: Grey indicates areas with insufficient data for making projections

SOURCES: ADAPTED FROM NRC 2011 AND LITTELL ET AL. 2009.

FIGURE 4. Homes at Risk from Wildfires in the Western United States



Development in or near wildfire-prone areas in the western United States is significantly raising the risks and costs of wildfires. The colors on the map show the percentage of homes in each state that are either in the very high or high wildfire risk categories. The figures in each state show the number of properties that have the highest numeric risk score, factoring in a property's proximity to very high or high wildfire-risk areas. New Mexico is one of the states with the highest percentages of homes in very high and high risk categories, based on terrain, fuel, and vegetation characteristics of the property itself.

SOURCE: BASED ON DATA BY CORELOGIC (BOTTS ET AL. 2013).

BOX 1.

Cultural Heritage: Bandelier National Monument and Los Alamos National Laboratory

Extreme precipitation, flooding, and wildfires have affected sites that are central to New Mexico's heritage. The rock carvings and cliff dwellings of Bandelier National Monument tell the story of some of the earliest inhabitants of the Americas, while their descendants live nearby in modern-day pueblos. Protecting the archaeological, ecological, and cultural features of this landscape has become more difficult as drought, large wildfires, and extreme flooding increase the risks to them and the infrastructure they depend upon. For instance, the Cerro Grande Fire raged through the area in 2000, damaging more than 70 percent of 470 archaeological sites on the adjacent property of Los Alamos National Laboratory, including ancestral pueblo structures and wooden homestead buildings (Nisengard et al. 2002). It also destroyed over 200 buildings in the nearby town of Los Alamos (GAO 2000), including several historic structures from the Manhattan Project era (Nisengard et al. 2002).

In 2011, the Las Conchas Fire, the second-largest wildfire in New Mexico history, burned much of the forest around Bandelier National Monument. Severe flooding from summer thunderstorms in 2011, 2012, and 2013 repeatedly washed out the popular Falls Trail and Frijoles Canyon Trail. Erosion from floods and extreme rainfall is now a major risk to the monument's archaeological heritage.

and Alamogordo during both the fire and related flood events after the fire. Yet the following year, 2012, the Whitewater Baldy Complex Fire surpassed the Las Conchas, burning more than 297,000 acres (Cleetus and Mulik 2014). Wildfires in 2013 to 2015 burned fewer acres annually than in the 2011 and 2012 fire seasons, but the lingering effects of catastrophic wildfires continued to impact the state (NIFC n.d.).

With over 35,000 homes in areas where the wildfire risk is "high" or "very high," New Mexico has the highest percentage of at-risk homes in the West (Figure 4) (Botts et al. 2015). Not surprisingly, the recovery costs from wildfires have soared as more fires, burning in hotter and drier conditions, have increased the risk to the state's residential and commercial properties. Beyond the costs of damage to property and recovery, fire suppression has become more costly as protecting communities and deploying prescribed fires have become more difficult (Cleetus and Mulik 2014).

Reducing Emissions, Building Resilience

New Mexico can take control of its future through a forward-looking, pragmatic response to climate change—a response that builds resilience to changes already underway and lessens emissions of heat-trapping gases.

REDUCE EMISSIONS

Efforts to reduce emissions and transition New Mexico toward low-carbon energy sources are needed in a state that ranks twelfth nationally in energy-related carbon dioxide emissions per capita (EIA 2015b). More than half of the state's nearly 54 million metric tons of CO_2 emissions in 2013 came from the electric power sector, which depended on coal-fired power plants to provide 67 percent of total in-state electricity generation (EIA 2015b; EIA 2015a).

Fortunately, smart and meaningful efforts to transition New Mexico toward a lower-carbon economy are underway. These four steps could pave the way for New Mexico to pivot toward a low-emissions economy—one that recognizes the value of key economic sectors by protecting them from the effects of a changing climate.

1. **Accelerate the pace of investing in renewable energy and strengthen the Renewable Electricity Standard.** New Mexico is blessed with a diverse mix of renewable energy resources, which has helped the state meet interim benchmarks toward its existing renewable electricity standard (RES), a state-established requirement that utilities supply 20 percent of their power from renewable sources by 2020 (Heeter et al. 2014). At the end of 2014, New Mexico already ranked tenth among all states for cumulative installed solar capacity, with more than 150 MW coming online from 2012 to 2014 (SEIA 2014). At that time, New Mexico had developed 812 MW of wind power that provided 7 percent of the state's electricity (AWEA n.d.). Another 330 MW of wind power capacity is under construction (AWEA n.d.).

   Nevertheless, these investments fall far short of the state's tremendous renewable energy resource potential, much of which is economically viable but remains untapped. According to the U.S. Department of Energy, New Mexico's renewable energy economic potential—led primarily by solar and wind—could produce up to an additional 3,726 terawatt-hours of electricity, which is equivalent to more than 100 times the state's current electricity generation (Brown et al. 2015). Western New Mexico's geologically active regions also hold significant geothermal potential.

State-level RES policies are among most successful and cost-effective means for driving renewable energy development in the United States (Heeter et al. 2014; UCS 2013). By extending and expanding its current RES, which is now set to level off at 20 percent in 2020, New Mexico can encourage low-carbon, efficient energy sources to play a leading role in the state. The examples of states that have committed to targets of at least 40 percent RES by 2030 suggest that New Mexico may be able to double its share of renewable electricity (Barbose 2016).

2. **Manage energy demand through investments in efficiency.** Investing in energy efficiency in homes, businesses, and industry is an effective, affordable strategy for making the transition away from carbon-intensive fossil fuels. In 2014, efficiency investments in the state lowered retail electricity sales by more than half a percent, a significant achievement for a single year (Gilleo et al. 2015). This effort was largely spurred by an important commitment New Mexico made when it adopted an energy efficiency resource standard (EERS) in 2008. Updated in 2013, the EERS requires electricity providers to implement efficiency programs that reduce electricity demand to 10 percent below 2005 levels by 2020 (Gilleo et al. 2015). Going further, a 2012 analysis found that New Mexico could cost-effectively cut electricity use at least 24 percent by 2020 (SWEEP n.d.).

   New Mexico could exercise greater control over its energy demand if its EERS were increased and extended beyond 2020. Leading states with EERS policies are demonstrating that they can reduce electricity use by 1.5 to 2 percent each year, compared with New Mexico's current target of 0.6 percent (Gilleo et al. 2015). New Mexico could ensure adherence to this policy by tightening energy efficiency building codes, helping ensure that new construction uses the most cost-effective and energy-efficient technologies and practices.

3. **Retire high-emissions coal plants.** While New Mexico relies on coal for most of its electricity generation, the economic competitiveness of its aging and inefficient coal power plants is in decline. A lack of modern pollution controls to protect public health—along with increasing competition from cleaner, lower-cost resources such as renewable energy and natural gas—is leading to the retirement of coal plants in the state (Fleischman et al. 2013). For example, three coal generators at a Four Corners facility were closed in 2013; two coal generators at the San Juan generating station are expected to close in 2017. Combined, these retirements will lower carbon emissions from New Mexico's coal power plants by as much as 37 percent (SNL Financial 2015).

4. **Craft a plan to comply with the federal Clean Power Plan.** The U.S. Environmental Protection Agency's Clean Power Plan requires New Mexico to reduce its power plant carbon emissions by 4.9 million tons by 2030, to 28 percent below 2012 levels (EPA 2015). To achieve its emissions-reduction target, New Mexico should develop and implement a strong compliance plan that places a priority on the use of renewable energy and energy efficiency, minimizes the risks of an overreliance on natural gas, and considers closing more of its economically challenged coal plants. New Mexico should also seek to collaborate with other states in its compliance strategy, as multistate efforts have proven successful in achieving cost-effective carbon reductions.

BUILDING RESILIENCE

Even if global efforts to reduce emissions succeed, the current levels of heat-trapping gases will cause the climate to continue to warm for decades, making it essential for New Mexico and its communities to build their resilience to the effects of climate change. Those impacts are costly, and while they heighten risks to the economic security of all communities, they often hit low-income and socially vulnerable communities the hardest (Task Force on Global Climate Change 2015; Melillo, Richmond, and Yohe 2014; IPCC 2014). The agricultural sector is perhaps most at risk, yet it is critical to the state's economy and generates billions of dollars in revenue each year. To survive, New Mexico agriculture depends on water—over 1.3 million acre-feet of water annually, or about 70 percent of the state's total water consumption (Bustillos and Hoel 2014).

New Mexico can prepare its economy by making good use of information resources and investing wisely in planning and response for intensifying wildfires, droughts, floods, and other extreme conditions that accompany climate change. State and community planners need to take future projections of climate change into account—including the way it might add to the effect of other stresses, such as wildfire vulnerability, increased evaporation of agricultural soils and surface reservoirs, and the risk of over-pumping groundwater.

Some New Mexicans are already showing initiative and creativity in the face of these challenges. By taking six steps, BOX 2.

Generations of Damage: Santa Clara Pueblo

Wildfires often hurt the people least equipped to respond effectively and recover quickly, including rural and tribal communities. In 2011, the Las Conchas Fire burned more than 16,000 acres belonging to the Santa Clara Pueblo community (Dasheno 2012). Wildfires leave the landscape bare and bake the soil, making it less permeable to water, thereby increasing vulnerability to runoff and flooding. Not long after the fire, disaster struck again when heavy rains in the Jemez Mountains surged through the scorched canyons. The pueblo, particularly vulnerable to flooding because of its location at the entrance to Santa Clara Canyon, was under a state of emergency after heavy rains sent tree trunks, boulders, and other debris rushing down the canyon, toppling power lines and washing out roads and bridges. Summer floods in 2012 and 2013 caused further severe damage to the area, forcing the pueblo to declare a state of emergency as fast-flowing water burst through dam structures built to protect the community.

"It will take generations for our community and lands to recover from the devastation of the fire," said Walter Dasheno, governor of Santa Clara Pueblo at the time of the floods. "And because of climate change it is not clear what the future will look like" (Dasheno 2012).

Larry1732/Creative Commons (Wikimedia Commons)

Climate change is increasing the frequency of wildfires, and making it more difficult to recover from their destruction. In 2011, the Santa Clara Pueblo community lost more than 16,000 acres of forested land to wildfire, which cleared the way for heavy flooding the new two summers.

state and federal policies should enable and build on such efforts to safeguard communities.

1. **Support and learn from communities taking systematic steps to reduce risks from wildfire.** In New Mexico, five communities—Elk Ridge, the Greater Eastern Jemez Wildland, Hidden Lake, the Village of Ruidoso, and Taos Pines Ranch—were cited as success stories when they received competitive "FireWise" grants from the National Fire Plan, aimed at reducing wildfire risk and potential home and property losses. Under that program, local fire districts provide communities and their residents with wildfire risk assessments, prescribe mitigation measures, and recommend options for enhancing the long-term health of forests.[4] Such valuable services could be expanded throughout the state, protecting lives and property, while reducing New Mexico's reliance on federal fire suppression efforts.

2. **Learn and share lessons from water innovators within the state who are working through difficult choices.** For example, water users in the Lower Rio Grande Basin in southern New Mexico have faced severe and sustained drought on top of an increasingly arid climate, yet the current priority system by which rights to use water are appropriated has led to more demand for water than can be sustainably supplied. In 2015, Elephant Butte Irrigation District implemented its Depletion Reduction Offset Program (DROP), which gives municipal and industrial water users access to combined groundwater and surface water rights through the leasing and fallowing of irrigated land to reduce depletions from agricultural use.

> *"It will take generations for our community and lands to recover from the devastation of the fire, and because of climate change it is not clear what the future will look like."*
>
> — Walter Dasheno, governor of Santa Clara Pueblo

The reduced demand for agricultural water has offset depletions caused by meeting municipal and industrial demand, allowing the system to remain in balance.

Another, longer-term example is the Rio Grande Water Fund, a public-private partnership that seeks to protect vital watersheds in northern New Mexico through large-scale restoration of forests and watersheds. The fund invests in thinning overgrown forests, restoring streams, and rehabilitating areas that have flooded after wildfires.[5] Although this fund was not designed to address climate resilience, it is well-suited to forward-looking action.

3. **Make better use of monitoring systems to provide early warning of drought, flooding, or other extreme conditions.** For instance, the New Mexico Climate Center housed at New Mexico State University operates a network of weather stations across the state and analyzes the climate data from them.[6] Farmers and ranchers, among others, can use this real-time climate data to help them anticipate and understand climate-driven weather events, inform irrigation schedules, and take proactive steps to protect their investments.

   Another source of information is the New Mexico Office of the State Engineer, which coordinates the Interstate Stream Commission responsible for monitoring the impact of climate change on New Mexico's water supply and the state's ability to manage water resources.[7] The office informs communities about water supply challenges and coordinates their responses. This role should be supported and enhanced.

4. **Ensure that state regulatory regimes recognize the impacts of climate change on resources and take those impacts into account when managing them.** Impacts the state is already experiencing include extreme variability in the supply of surface and groundwater, changes in the quantities and types of water-supply demand, and increases in forest fires and flooding. As the state considers options for planning and managing its water and other resources, it must actively assess current and future climate impacts and incorporate them into regional and state water plans in an iterative and ongoing way. Analyses based on more extreme projections, rather than median projections, provide a "stress-test" approach to considering how future climate extremes may affect water resources and water projects. They could be a helpful approach to managing the state's water resources and designing water infrastructure.

5. **Provide sufficient funding for regional and statewide water planning, administration, and infrastructure designed for the future, not the past.** Additional resources are needed to adequately understand, plan, and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One of New Mexico's largest commercial solar PV installations can be found at the Indian Pueblo Cultural Center. This project is a successful example of how New Mexico could increase its renewable energy resources to reduce emissions and build resilience.

   address water resource management needs across the state. Given growing demands for water resources to keep the state's economy thriving, investing in water resources pays multiple dividends, and in many ways that are not traditionally measured. For example, better infrastructure would give water managers more precise control over water allocation, helping farmers protect their economic stability, as well as strengthening the communities built upon the acequia irrigation system. In 2013, New Mexico Governor Susana Martinez took a significant step in this regard when she announced the allocation of $112 million from the state's capital investment fund to water infrastructure improvements, saying "Unprecedented drought, wildfires, and floods have put further stress on New Mexico's aging water infrastructure in communities large and small across the state" (Western States Water Council 2013). These funds are a critical step toward addressing unmet needs, which are expected to worsen with climate change.

6. **Adopt a groundwater measurement and accounting method that is well understood, broadly accepted, and properly integrated across the spectrum of water dealings.** Because groundwater cannot be plainly seen, a variety of metrics are used to assess groundwater levels and storage, including measuring extraction or employing modeling. Metrics and monitoring efforts can be tailored to fit state and local needs. For example, in North Texas, one Groundwater Conservation District measures groundwater extraction by installing a meter or device

to measure water flow that is accurate to within a few percent. In California, the Sacramento Central Groundwater Authority monitors its wells twice a year (SCGA 2012). If needed, scientists have demonstrated that groundwater usage can be effectively modeled in near-real-time with the support of satellite data (Zaitchik, Rodell, and Reichle 2008; Allen, Masahiro, and Trezza 2007). Metering electricity usage by groundwater wells to estimate groundwater pumped from individual wells is key to ensuring groundwater sustainability.

> *"Unprecedented drought, wildfires, and floods have put further stress on New Mexico's aging water infrastructure in communities large and small across the state."*
>
> — Governor Susana Martinez

BOX 3.

Federal Initiatives

- The multiagency National Drought Resilience Partnership, established in 2013, helps states and communities measure and analyze data on water supplies, snowpack, and soil moisture; develop watershed-wide drought plans; and develop resources to help farmers and other water users measure and conserve water and enhance soil health.[8]
- The National Water and Climate Center, a project of the National Resources Conservation Service, conducts the New Mexico Snow Survey Program, providing mountain snowpack data and streamflow forecasts for the state.[9]
- The Southwest Climate Science Center, located in Tucson, Arizona, is a collaboration of scientists and resource managers to better plan for and adapt to climate change in the region.[10]
- The Southwest Climate Regional Hub, located at New Mexico State University in Las Cruces, is one of seven U.S. Department of Agriculture hubs established across the country to help farmers and ranchers adapt their operations to a changing climate.[11]

While many existing federal programs can alleviate some costs, Congress should increase national investments in a number of programs, including the following:

- The New Mexico Drought Preparedness Act of 2015, introduced by U.S. senators Tom Udall and Martin Heinrich, would provide drought relief and address long-term drought challenges by improving the efficiency and effectiveness of water management in the state. If enacted, this act would address drought conditions by targeting critical water-management challenges in the Rio Grande River Basin, which is the state's largest and most economically important watershed. The act would provide for technical assistance to foster a federal acquisition and local water trading program, studies aimed at optimizing basin infrastructure management, maintenance of flow management for ecosystem benefits, and additional funding for drought mitigation and relief.
- The Pre-Disaster Mitigation Grant program is designed to reduce risks to people and property and to diminish reliance on federal funding when disasters occur. The program helps fund hazard-mitigation planning and projects that reduce New Mexico's vulnerability to floods, wildfires, and other extreme weather events.[12]
- The Western Watershed Enhancement Partnership helps reduce wildfire risks to water supplies by partnering with local businesses to clear flammable forest debris and manage forests in ways that strengthen resilience.[13]

Federal investments in climate preparedness and resilience can help protect communities in New Mexico. Larger appropriations and strategic grants for these and similar programs would help New Mexico prepare for droughts, wildfires, and other impacts of climate change, as well as assist communities in times of need and speed recovery when those impacts are felt.

The federal government must make the latest science and data easily accessible to states and communities, delivering them before critical decision moments and leading to better-informed planning decisions. Agencies at all levels of government need to reevaluate existing programs, hold steady or increase disaster-response efforts, and place a high priority on preparedness for climate-change-fueled natural disasters, which are expected to become more harmful and costly. Without smart investments now, the costs will strain the ability of even the most resilient and resourceful communities to cope and recover, draining the budgets of state and local governments.

New Mexico's Path to a Strong, Resilient Future

New Mexico has a long history of facing a challenging climate, and New Mexicans have learned to be resourceful and resilient. The state has invested in meeting the needs of its people, while using approaches and policies aimed at keeping its economy within the limits of its available resources.

The future climate will alter these circumstances, changing the availability of vital resources, making past investments obsolete, and testing the resourcefulness of New Mexico's people. New Mexico can survive and even thrive in this new world, but only if it takes wise steps today. As the future unfolds, New Mexicans deserve the commitment of state and federal policy makers to doing the utmost to limit risks and helping the state become more resilient to the unavoidable challenges.

New resources and investments are only part of the solution. When the state empowers its people to makes better choices for themselves—backed up by forward-looking investments—the people of New Mexico can forge a new path to a resilient future, as they have done many times before. The challenge today is for New Mexico to take the steps necessary to effectively manage and reduce the impacts of climate change and ensure the future security of the state and its residents.

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ENDNOTES

1. *The latest National Climate Assessment, the third, was developed by a team of more than 300 experts, guided by a 60-member Federal Advisory Committee. The report was extensively reviewed by the public, a panel of the National Academy of Sciences, and other experts, including from federal agencies. For more information, see:* http://nca2014.globalchange.gov.
2. *These figures are in comparison with a 1901–1960 reference period.*
3. *These figures are in comparison with a 1971–1999 reference period.*
4. *For more information about the FireWise success stories, see:* www.firewise.org/wildfire-preparedness/be-firewise/success-stories/new-mexico.aspx?sso=0.
5. *For more information about the Rio Grande Water Fund, see:* www.nature.org/ourinitiatives/regions/northamerica/unitedstates/newmexico/new-mexico-rio-grande-water-fund.xml.
6. *For more information about the New Mexico Climate Center, see:* http://weather.nmsu.edu.
7. *For more information about the New Mexico Office of the State Engineer and the Interstate Stream Commission, see:* www.ose.state.nm.us/index.php.
8. *For more information about the National Drought Resilience Partnership, see:* www.drought.gov/drought/content/ndrp.
9. *For more information about the New Mexico Snow Survey Program, see:* www.nrcs.usda.gov/wps/portal/nrcs/main/nm/snow.
10. *For more information about the Southwest Climate Science Center, see:* www.doi.gov//csc/southwest/index.cfm.
11. *For more information about the Southwest Climate Regional Hub, see:* http://swclimatehub.info.
12. *For more information about the Pre-Disaster Mitigation Grant program, see:* https://fema.gov/pre-disaster-mitigation-grant-program.
13. *For more information about the Western Watershed Enhancement Partnership, see:* www.usda.gov/wps/portal/usda/usdahome?contentid=2013/07/0147.xml.

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IMPACTS OF OIL AND GAS DRILLING ON INDIGENOUS COMMUNITIES IN NEW MEXICO'S GREATER CHACO LANDSCAPE

UCLA Institute of the Environment and Sustainability
for WildEarth Guardians

WildEarth GUARDIANS

UCLA IoES

Photo by [Andrew Kearnes]

Foreword

This report was crafted by seven environmental science students of the Institute of the Environment and Sustainability (IoES) at the University of California, Los Angeles. This work was produced in collaboration with WildEarth Guardians.

We would like to recognize that the University of California, Los Angeles resides on the traditional home belonging to the Tongva, Chumash, Tataviam, and Acjachemen Nations. We recognize all of the Honuukvetam (Ancestors),'Ahiihirom (Elders), and 'eyoohiinkem (our relatives/relations) past, present, and emerging.

We would also like to thank all who have made this project possible, including, but not limited to: our advisor, Noah Garrison; our client liaisons, Jeremy Nichols and Rebecca Sobel; those who provided valuable feedback on our project proposal and this report, Felicia Federico, William Boyd, and Pablo Saide; those who helped to edit and finalize this report, Jon Christensen and Mishuana Goeman; and Noam Rosenthal, who provided valuable feedback on our methodology and technical appendix.

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Photo by Andrew Kearnes

Introduction

New Mexico has been home to many Indigenous communities for thousands of years. It is currently home to 23 federally recognized tribes, including 19 Pueblos, 3 Apache Tribal Nations, and the Navajo Nation. These communities continue to care for their existing and traditional homelands, but are threatened by historical and continued rapid expansion of oil and gas development.

The northwestern region of New Mexico, known as the Greater Chaco region, is rich with cultural sites and gathering spaces. The region is a checkerboard of federal, state, tribal, private, and Navajo allotment land, and while Navajo (or Diné) communities call this land home, the Chacoan Landscape is the homeland of the Ancient Puebloans, ancestors of the modern day Pueblos that still trace their lineage to this sacred area. Despite this, 91% of public lands in the region are leased for oil and gas drilling. These operations are often concentrated in and around Navajo communities.

Members of the Navajo Nation are twice as likely to live within half of a mile of an oil and gas facility compared to the rest of the New Mexico population. Living near an oil and gas facility increases exposure to toxic pollutants, which is directly associated with acute and chronic health risks.

Regulations aiming to mitigate public health risks resulting from oil and gas development, including the federal Clean Air Act, are overseen by a variety of federal and state agencies, sometimes with complex, overlapping jurisdiction. But loopholes and shortcomings in tracking and enforcement of oil and gas activities, including well and facility construction, open the door to rampant expansion of oil and gas production at best, or worse, to potential violations of state and federal law that greatly increase the air pollution experienced by communities throughout the region.

How oil and gas regulatory violations could be further harming Indigenous communities in the Greater Chaco Region.

Graphic by frackoffchaco.org #frackoffchaco

Our research indicates that some stages of oil and gas development may be occurring before required permits or agency approvals have been obtained. Before any construction or activity of any kind can be undertaken by an oil company, including drilling wells or clearing land for an oil pad, the Clean Air Act requires that a proposed facility obtain a permit covering the air pollution emissions that will be released.

We analyzed 69 well-facility pairings, or wells drilled since 2010 that we could positively associate with a specific, permitted facility, in the Greater Chaco region of New Mexico. Of these, only 62 had sufficient data available for both the well and associated facility to determine their permitting timeline. **We found that 35% of the wells in those pairings were constructed before required permits for their associated facilities were obtained.**

Although this analysis was completed on only a small subset of wells, our findings indicate that these types of violations may be more widespread across the region. **The potential for illegal drilling means that the air pollution released near Indigenous communities may actually be far greater than what is considered safe under current environmental regulations.** And too often, decisions regarding oil and gas development are made without adequate Tribal consultation (see section “COVID-19 and the Navajo Nation”).

As **Indigenous communities bear the greatest burden of oil and gas development**, it is critical that these communities have the opportunity, with free, prior, and informed consent, **to actively engage in the necessary conversations critical to their self-determination as sovereign Indigenous Nations.**

Photo by Andrew Kearnes

The Greater Chaco Region

91%

of public lands in the Greater Chaco region are leased for oil and gas drilling.

The Greater Chaco Landscape is a vast cultural landscape in the Four Corners region of the United States. The region has been home to many Indigenous Nations for thousands of years. In New Mexico, Greater Chaco is loosely defined as an 8,000 square-mile area surrounding Chaco Canyon National Historical Park and a UNESCO World Heritage Site that protects the center of Indigenous cultures in the region. Much more than a park or archaeological site, the area, nestled in the high-desert of northwestern New Mexico, is home to living cultural practices and traditions that extend far beyond the park's boundaries. Chaco and the living landscape that surrounds it are sacred to Diné and Pueblo peoples throughout the region. These communities and their ancestors have fought for the preservation of their homelands, their culture, and their stories. Today, they continue to be burdened by the aftershocks of the growth of extractive industries -- including fracking operations.

91% of public lands in the Greater Chaco region are leased for oil and gas drilling. These operations are often concentrated in and around Tribal communities and major cultural sites. In 2014, the Bureau of Land Management estimated that approximately 4,000 of the over 37,000 wells in the region are used for fracking, an unconventional method of oil drilling that is associated with a number of environmental harms and public health risks.

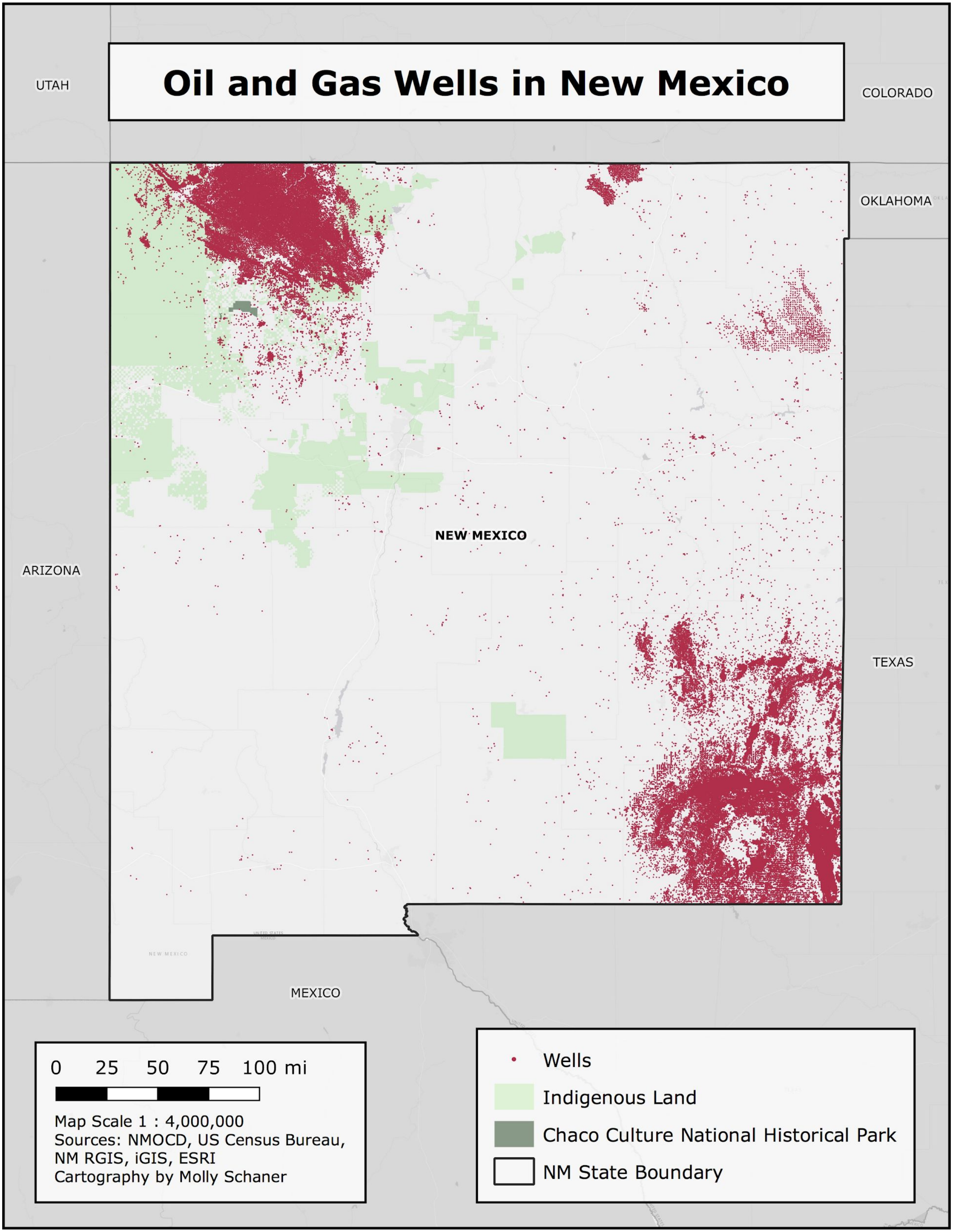


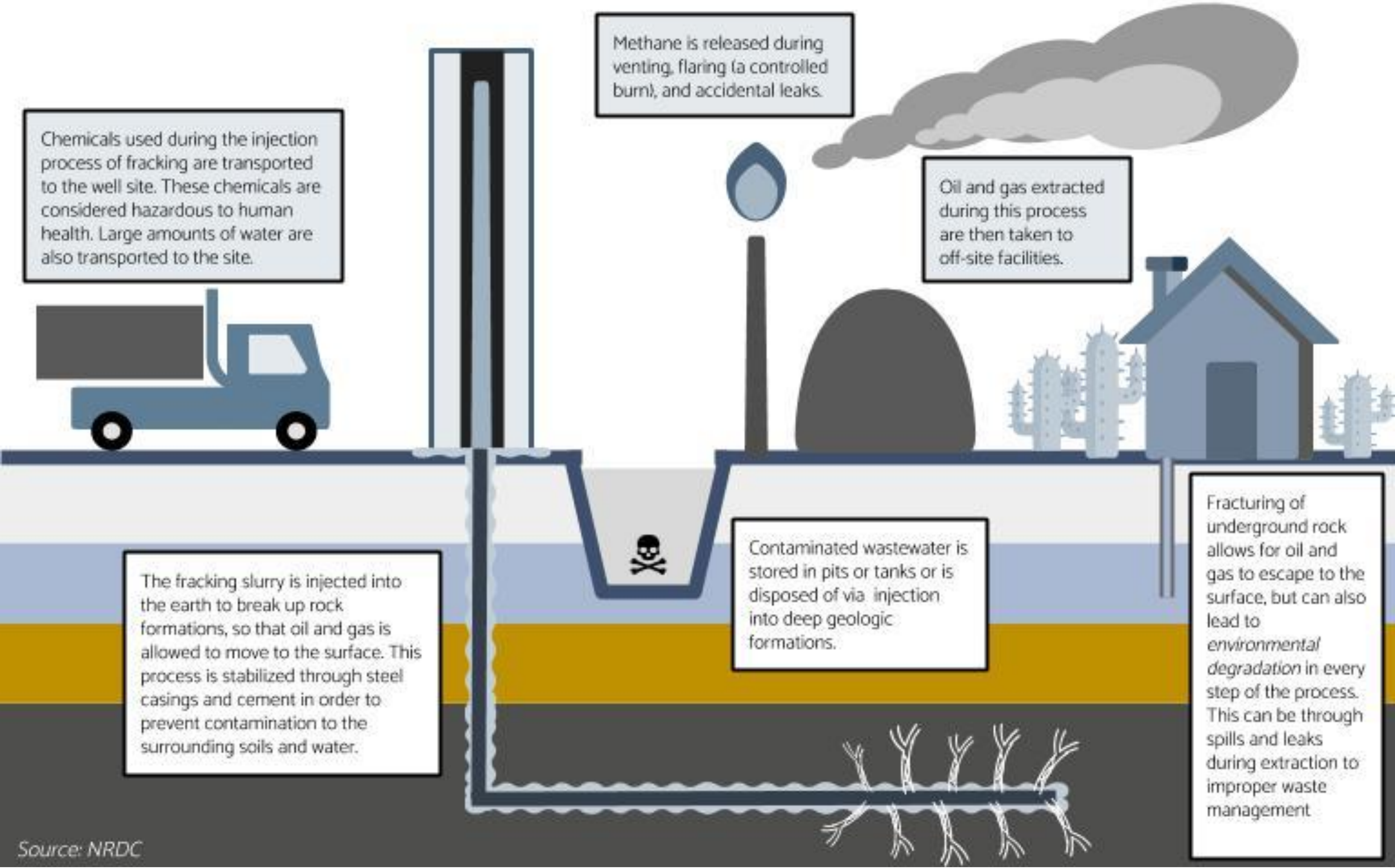
Figure 1. This map depicts the location of all oil and gas wells in New Mexico in relation to federally recognized indigenous land. In addition, the borders of Chaco Culture National Historical Park, an epicenter of Indigenous culture, is outlined in a dark green just south of the San Juan Basin well clusters.

What is Fracking?

According to the U.S. EPA, the slurry used in fracking **contains an average of 14 additive chemicals.** Of the additives that have toxicity information, it was reported by the NCBI that **nearly half are reproductive toxicants, developmental toxicants, or both.**

Hydraulic fracturing or “fracking” is distinct from conventional oil and gas drilling, although both are problematic in terms of environmental degradation and potential public health risks. In conventional oil and gas drilling, a well is drilled into a rock formation and oil or gas are pumped from the rock at depth back to the surface. However, there are some rock formations that are so tightly packed together that they must be broken up to create pathways for oil and gas to get to the well, either because the reservoir has already been depleted or because the natural geology makes extracting the oil and gas difficult.

Fracking allows oil companies to access hard-to-reach oil and gas by forcibly injecting a slurry of water and chemicals -- some of which may be toxic -- into the rock to break it up and allow the oil and gas to move freely up to the surface.



Public Health and Environmental Impacts

Oil and gas drilling, including fracking operations, release toxic pollutants into the air that are associated with serious health impacts, including respiratory problems, cancer, and cardiovascular disease. Particularly, hazardous air pollutants like benzene, toluene, ethylbenzene, and xylene (BTEX) are emitted during regular operation of the wells. This group of volatile organic compounds (VOCs) is associated with headaches, fatigue, and, with high or long-term exposure, cancer.

VOCs are also associated with the production of ozone. When VOCs or other ozone precursors react with sunlight, ozone is formed. Nitrogen oxides (NOx), which are emitted by engines used for drilling as well as by the large fleets of diesel vehicles often associated with oil and gas production activities, are another example of an ozone precursor. Ozone is known to reduce pulmonary function and exacerbate breathing problems like asthma and emphysema. Because ozone can travel long distances from where it forms, its harmful impacts can be widespread.

Fracking-related machinery also produce particulate matter, which is linked to a higher risk of cardiovascular disease and cancer. The New Mexico Environment Department (NMED) has reported that five counties, including San Juan county, experience concentrations of particulate matter that are higher than the concentration considered allowable under the Clean Air Act.

Although both conventional well drilling and fracking are harmful to human health and the environment, multi-stage drilling and horizontal fracking operations are considered to be more dangerous, largely due to the water and chemical slurry. While much of this fluid ultimately remains underground (potentially causing its own set of problems), some of the slurry, mixed with water or brine from the rock formation, eventually returns to the surface. Since it can contain toxic or hazardous chemicals, disposing of this "produced water" can pose serious problems. For example, in many cases the waste product must be hauled out by trucks for proper treatment offsite, which results in increased air pollution from the vehicles. Where the fluid remains in the ground or where it is injected back into the ground for disposal, the chemicals from the slurry may leak into drinking water reserves, either through cracks in well casings -- the lining of the well that is supposed to prevent leaks -- through cracks in the rock, or through spills on the surface that leach into the ground. 87% percent of public water supply in New Mexico comes from groundwater, making groundwater contamination especially problematic.

ARE SAN JUAN COUNTY RESIDENTS PROTECTED?

The closer an individual or community is to oil and gas operations, the greater the health risks of these operations become. Experts recommend that oil and gas facilities be **at least 1350--2500 feet away from residences or any location of human activity.** This protects individuals from exposure to dangerously high **levels of toxic air pollutants, loud noise, and strong odors.**

However, in San Juan County, the required setback distance is determined by each municipality, and it is often **significantly smaller than recommended -- sometimes just 200-400 feet.** Although uncertainty remains due to gaps in long term health and exposure data, the short setback distances in San Juan County indicate that county **residents living close to oil and gas facilities may experience greater health risks and undesirable nuisances.**

As discussed in the following section ("Impacts on Fracking on Indigenous Communities"), Indigenous communities may already be feeling the impacts of oil and gas development. **San Juan county is one of 238 counties in the United States that are experiencing a higher risk of cancer as a result of oil and gas development.** Furthermore, it is one of 32 counties at a high risk of respiratory harm, including breathing problems or respiratory diseases.

PUBLIC HEALTH RISKS OF FRACKING

WELL SITE PREPARATION & CONSTRUCTION

Particulate Matter
NOx
Dust
Noise

- Cardiovascular disease
- Respiratory and pulmonary disease, cancer, exacerbation of asthma and emphysema
- Stress, sleep deprivation

WELL DRILLING, FRACKING, WELL COMPLETION

- Respiratory and pulmonary disease, cancer, exacerbation of asthma and emphysema
- Brain damage, neural tube defect, headache
- Reproductive failure

Benzene, Ethylbenzene, Toluene, Xylene, Volatile Organic Compound, leaching of toxic fracking fluid, NOx

HAZ WASTE

FLARING, VENTING & STORAGE

Benzene, Toluene, Ethylbenzene, Xylene, Volatile Organic Compounds, Particulate Matter, NOx, CO, Methane

- Respiratory and pulmonary disease, cancer, exacerbation of asthma and emphysema
- Brain damage, fetal development defect headache
- Global warming, fire and explosive hazard

WELL ABANDONMENT & WASTE MANAGEMENT

- Cancer
- Stress, anxiety
- Global warming, fire and explosive hazard

Methane
Radioactive materials
Land destruction

Sources: Natural Resource Defense Council, Centers for Disease Control and Prevention, Agency for Toxic Substances and Disease Registry

WHAT ARE THE TOP 5

LEADING CAUSES OF DEATH IN SAN JUAN COUNTY?

*Based on 2008-2018 data from New Mexico Health Department

Cardiovascular disease

Cancer

Research* suggests that San Juan County residents are at a ***higher risk*** of developing cancer and respiratory diseases due to ***toxic oil and gas emissions***

Unintended injury

Cerebrovascular disease

Lower respiratory disease

* Clean Air Task Force, (2016). "Fossil Fumes: A public health analysis of toxic air pollution from the oil and gas industry"

Impacts of Oil and Gas Development on Indigenous Communities

For Indigenous communities, health risks associated with living near oil and gas facilities are exacerbated due to a lack of access to health facilities, clean drinking water, consistent housing, and sanitary sewage and waste disposal, among other risk factors. Over [30% of Navajo households](#) do not have clean running water at home. Only seven hospitals directly service the 27,000 square mile Nation, meaning that travel time to the nearest hospital can be upwards of an hour or more, exacerbated by unpaved roads.

Graphic by [frackoffchaco.org](#) #frackoffchaco

Ultimately, the detrimental impacts of oil and gas activities on Indigenous communities are compounded by the systemic harms they have experienced throughout history. Learn more about the historical events that have and continue to impact Tribal communities and how they are affected by oil and gas development in the next page.

In addition to public health risks, Indigenous women of New Mexico may also be dangerously affected by oil and gas activity. New Mexico has the highest number of cases of missing and murdered Indigenous women and girls in the United States. This may be exacerbated by transient male workers -- often employed for oil and gas drilling -- near Indigenous lands. A United Nations (UN) rapporteur on the rights of Indigenous people, shows a trend of “extractive projects … [leading] to increased incidents of sexual harassment and violence, including rape and assault” (Anaya 2010). [In North Dakota](#), reported sexual assaults of Indigenous women increased during a period of peak oil production that ended in 2014. Unfortunately, data on this phenomenon in New Mexico are extremely limited. Given the similarities between cases reported in North Dakota and those reported in New Mexico, it is critical that additional investigations address the potential link between New Mexico’s missing and murdered Indigenous women and extractive projects.

The relationship between tribes and oil and gas development is complex, and opinions within and among Tribal communities and governments on this development varies widely. Despite the harms incurred by development, ***tribes sometimes derive income from oil and gas development, either by owning wells or leasing land.*** *In 2012, energy and mineral extraction generated over [$701 million](#) in royalties for Indigenous mineral owners. Ultimately, resource extraction is a complicated social, political, and environmental issue*

History of the land:

IMPACTS OF OIL AND GAS on NATIVE NATIONS

The **colonization of Indigenous peoples** has led to an intense and vast history that **continues to affect** how Indigenous communities today experience the **effects of oil and gas development**

1492

European colonizers arrive. This marks the beginning of the annexation of Indigenous land for colonization.

1864

The Long Walk. A forced removal of the Navajo Nation displaced many Native peoples to free up land for corporate and government interests.

1924

Indigenous people granted citizenship in the US. Prior to this, Indigenous Nations were not allowed to vote on legislations that would later impact their land, community, culture, and livelihoods.

1974

The Greater Chaco region is designated a sacrifice zone. A report by the United States National Research Council designates western lands, such as in the San Juan Basin of northwest New Mexico, as ”national sacrifice zones” for energy production, where there is no chance of rehabilitating the land.

1976

President Ford established the Indian Health Care Improvement Act. This Act granted federal funds to reservation health care facilities. However, it was not permanently adopted until 2010. During this 34-year gap, there were a number of periods that the Act was not reauthorized, leaving Native healthcare providers at risk of losing their funding.

2009

Reservation clinics raise concerns due to being overcrowded and underfunded. The legacy of limited funding and a lack of attention by the federal government is present in long wait times at clinics, a shortage of doctors and nurses, and insufficient care. This means that health impacts from fracking may be under-reported and/or untreated.

May 2020

Indigenous Nations of New Mexico has the highest COVID-19 infection rates in the US. The Navajo Nation, in particular, has been the most impacted due to lack of access to clean water, food, and healthcare facilities. The close proximity to oil and gas activity and its pollution could be linked to worse healthcare outcomes related to the disease -- a recent Harvard study has linked higher COVID-19 death rates to living in areas with higher pollution.

Photo by Andrew Kearnes

Regulating Oil and Gas in New Mexico

In New Mexico, oil and gas development is regulated through a complex network of both state and federal laws, with multiple agencies then tasked with handling various aspects of permitting for oil and gas well drilling and operations, for permitting of facilities and related infrastructure to process or store oil and gas, and for enforcement of regulatory and health requirements. This complex bureaucratic web can make it difficult to adequately assess compliance with regulatory requirements.

The potential risks posed by oil and gas development in New Mexico are especially problematic due to the opportunity for potential violations to fall through the cracks.

The primary law governing the regulation of oil and gas development in the United States is the federal Clean Air Act of 1970. The federal Clean Air Act regulates the emission of air pollutants "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population" (42 U.S.C. § 7401(b)(1)). In 1990, the Act was amended to require, among other things, that major sources of air pollution obtain and comply with an operating permit under the Act's Title V permit program. Sources are classified as "minor" or "major" based on the amount of air pollution they emit.

If an oil or gas facility is considered a major source of air pollution, then that facility is required to obtain and comply with a Title V operating permit before starting to operate. This permit requires that the facility monitor and limit their pollution emissions in order to meet air quality standards set by the Act. In other words, the permit program helps to monitor and control the emissions coming from oil and gas facilities.

Major sources include any facility or "source" that emits or has the potential to emit more than 100 tons per year of any pollutant, though that limit may be lower for some hazardous pollutants or in areas where air quality does not meet the Clean Air Act's standards for what are known as "criteria pollutants" -- pollutants such as lead, ozone, and particulate matter that cause smog and other health hazards.

Facilities include all of the equipment that process and treat the oil or gas pumped by wells so that it is ready to be used. Facilities associated with oil and gas development release air pollutants such as BTEX, NOx, and particulate matter that cause acute and chronic health complications, such as asthma attacks, cardiovascular disease, and cancer.

WHAT IS CONSIDERED A "MAJOR SOURCE"?

The minimum emissions levels to be classified as a major source are known as **Major Source Thresholds (MST),** and they depend on both the *amount* and *type* of air pollutants that a source emits.

The first and second MST pertain to **"hazardous air pollutants"**. These are 187 pollutants identified by Congress that are known or suspected to cause "adverse environmental effects" or "adverse human health effects" such as cancer [42 U.S.C. §7412(b)(2)]. Some examples of hazardous air pollutants include **benzene and toluene,** which are volatile organic compounds frequently emitted as a result of oil and gas drilling, as well as **mercury and asbestos.**

If a facility emits **25 tons per year or more** of multiple hazardous air pollutants or 10 tons per year or more of a single hazardous air pollutant, it is considered a major source.

The third MST applies to **"any air pollutant"**. While these other pollutants are not classified as hazardous, they can still be toxic to humans in large quantities or after long-term exposure. These pollutants include what are known as **"criteria pollutants"** - **lead, carbon monoxide, sulfur dioxide, nitrogen dioxide, ground-level ozone, and particulate matter** - which build up in the atmosphere, causing smog and health problems among other concerns.

If a facility emits **100 tons per year or more** of any air pollutant, it is considered a major source.

Potentially Unlawful Drilling in Chaco

The Challenge of Enforcement

Photo by Andrew Kearnes

Under the Clean Air Act, if an operating permit is required, it has to be issued before ANY activity towards operation, or even construction begins. A violation of this rule means there may be more pollutants being released than is allowable under the Clean Air Act. This directly translates to increased health risks for surrounding communities.

> Although the definition of what constitutes **activity** for purposes of an operating permit is debated, we interpret activity to cover a wide range of possible actions, such as clearing land for a well pad, constructing buildings or structures at the site, or drilling a well that will supply oil or gas to the permitted facility. Our definition, then, includes both construction of facilities, which are directly permitted by the Clean Air Act and clearly constitutes "activity", and the construction of wells, which supply the facilities but may not be directly permitted themselves.

In New Mexico, however, even if a facility would not be considered a major source, and as a result would not need a Title V permit to operate, anyone planning to construct a new facility that has the potential to emit more than 10 tons per year of a regulated pollutant is required to submit a "Notice of Intent" (NOI) to operate the facility to the New Mexico Environment Department (NMED). Similar to the Clean Air Act, before a facility can begin ANY activity towards construction, the facility must receive either a response from NMED confirming that a permit is not required, or if a permit is required, must receive the final approved permit.

Unfortunately, it can be difficult to determine whether wells have been drilled before any permit or NOI has been issued for the facilities that will receive oil or gas from them. This is because responsibility for permitting the drilling of wells and for construction and operation of facilities are split between two entirely different state agencies -- NMED is responsible for the permitting of facilities while the Oil Conservation Division (OCD) is responsible for permitting the construction of new wells. Even more problematic is that facilities are generally supplied by multiple wells, and well fields may have clusters of several wells within relatively close proximity, making it difficult to determine which wells and facilities are related.

Unfortunately, NMED and OCD do not require facilities applying for a permit to identify which wells will be associated with them, or keep records of which facilities are associated with which wells in general.

Because it can be so difficult to tell which facility a well will be connected to, it is often difficult or impossible to tell whether a well might have been constructed before the required permits for its associated facility were obtained, or whether state or federal permitting requirements have been violated.

Our Analysis

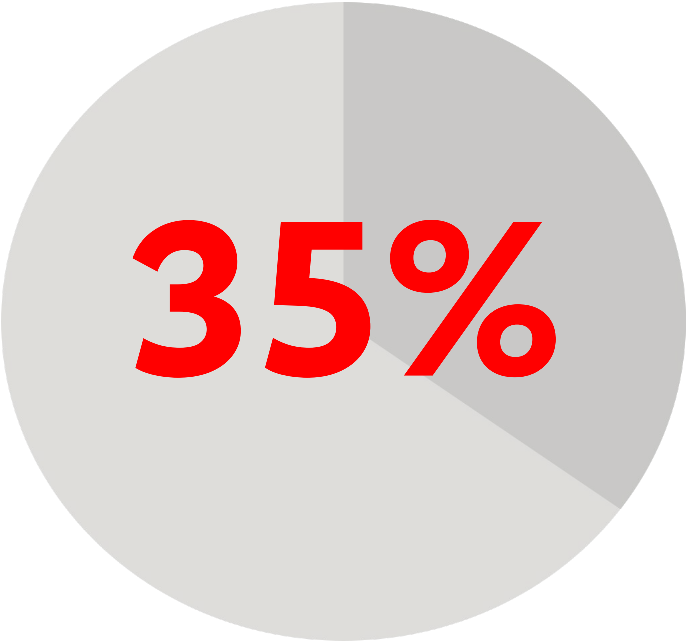
To determine whether potential violations of permitting requirements may be occurring in the Greater Chaco Region, we analyzed 69 well-facility pairings, or wells drilled since 2010 that we could positively associate with a specific, permitted facility in San Juan County. We primarily focused on wells producing oil through fracking. We obtained permitting data for potentially associated facilities through both searching for documents available on the NMED website and by filing a series of requests for permitting documents to NMED under New Mexico's Inspection of Public Records Act. We then attempted to connect each well to the facility they supply using a combination of information obtained from the permit materials and by using mapping and geospatial information to identify wells and facilities that are clustered in close proximity to each other, indicating they are likely associated.

We then examined Clean Air Act permits and NOIs for facilities from NMED and compared the notice or permit approval date for a facility to the date that facility's wells were drilled, as recorded by OCD (only 62 of the 69 wells were paired with facilities that had information available allowing us to determine a complete permitting timeline). If a well was drilled before a Clean Air Act permit or NOI was approved for its associated facility, we considered this a potential violation.

Our analysis focused on a set of 289 oil and gas wells in San Juan County drilled by **Enduring Resources** or **Hilcorp Energy Company**, two of the region's largest operators, since 2010. The 289 oil and gas wells were broken down into three distinct groups: Enduring oil wells, Enduring gas wells, and Hilcorp gas wells. Based on geographic proximity to the wells, we then marked off a total of 602 unique facilities for subsequent analysis.

Ultimately, we identified 41 unique facilities that we were able to pair with one or more of 69 of the 289 total wells. However, only 36 of these facilities, representing 62 of the paired wells, had enough information available to construct a complete permit timeline.

We found that 35% of the wells we surveyed where a complete permitting timeline was available were constructed before the required permit documents for their associated facilities had been obtained.



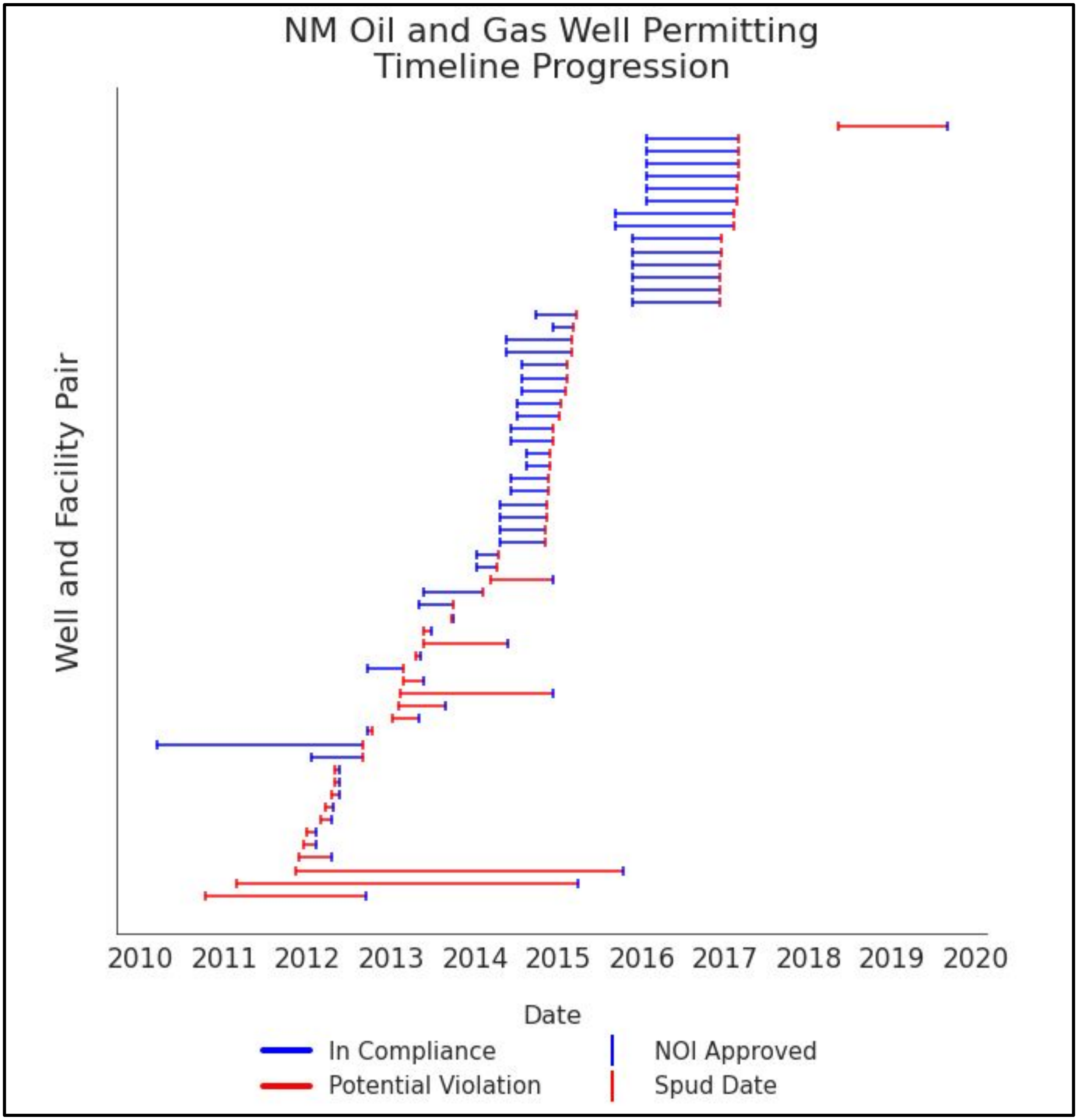


Figure 2. Of the 62 well-facility pairs with a complete permitting timeline, 35% of the wells were constructed (Spud Date) before the company received the approval of their notice of intent for operation of the associated facility (NOI Approved) from the NMED.

Although our analysis was limited to an extremely small subset of facilities, our findings **indicate that illegal drilling may be more widespread across the Greater Chaco Region.**

If this is the case, that means individuals -- specifically, the **Navajo communities of the region -- are being exposed to more dangerous air pollution** than they should be -- and more than regulatory agencies recognize.

Figure 3 displays a small sampling of facilities that we studied in San Juan County. The circle around each facility shows a 1500 foot buffer. This buffer was chosen based on the setback distance recommendations by policy experts and scientists to ensure public health and safety.

The buffers are then colored depending on the amount of volatile organic compounds the facility is authorized to emit under its permit - ranging from 0 to 237 tons per year. As shown, the potential for emission of VOCs -- long-term exposure to which is associated with memory issues and cancer -- from these facilities is high.

Each facility is additionally color-coded according to whether we conducted a review of that facility's permitting documents and construction records for its associated wells -- facilities in this study area with a blue or yellow center dot (18 of the 53 total facilities shown) were reviewed, while facilities with a black center dot (35 of 53 wells shown) were not reviewed for this analysis.

A cluster of 5 of the 18 wells we reviewed (shown in yellow) are in potential violation of permitting rules, as records indicate that wells associated with these facilities were constructed before either the facilities' air permits were issued or NOIs were approved. This represents more than one-quarter of the assessed facilities, and as the majority of the facilities in this area have not been reviewed yet, is an indication that more violations could be occurring in this area.

For many of the facilities we did not ultimately analyze, we were not able to clearly link a well to a facility, often due to limitations in available data from NMED and OCD or other agencies. Current laws do not require oil and gas developers to submit information regarding facility-well connections to the agencies with their permit applications, and both agencies stated they do not collect this information themselves.

As our research showed, in many cases the information these agencies collect is not readily available online and must be obtained through Public Records Act requests. In other cases, the agencies are simply not collecting information that would help in assessing compliance with relevant laws or understanding the extent of emissions from oil and gas operations. This makes tracking and monitoring potentially illegal drilling or its effect on the public difficult.

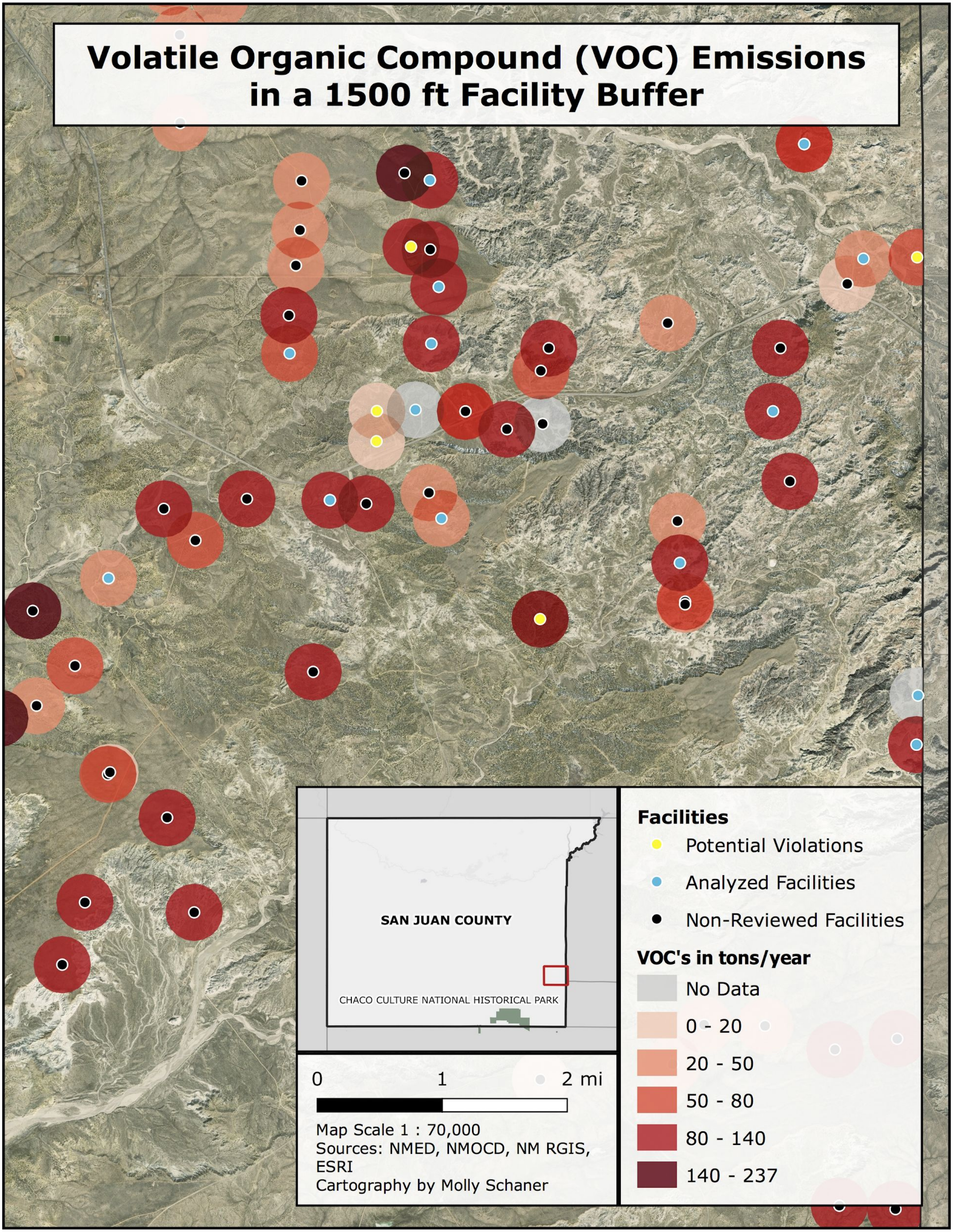


Figure 3. Subset of San Juan County featuring VOC emissions from oil and gas facilities with potential permitting violations, facilities analyzed by this project that had no permitting violations, and facilities not analyzed by this project.

Solutions

Since Indigenous Nations are experiencing the most harmful impacts of oil and gas development, including potential illegal practices, it is critical that Indigenous communities have the opportunity to be included in any regulatory or decision-making processes that involve oil and gas development and are potentially allowing these violations to occur.

Encouraging Agency Transparency

Both NMED and OCD make only limited data available for the public through easily accessible online portals. Most relevant permit documents from NMED must be obtained through a Public Records Act request to the agency. This additional step, although detailed on the NMED website, largely acts as a barrier to obtaining information that would benefit communities and better allow them to empower change. And while the OCD website does include multiple databases of well drilling documents, there is no available means of connecting those wells to the facilities they service or to broader permitting or regulatory schemes. Promoting the use of a database of all permitting documents on the NMED website would create a higher level of transparency that can discourage industries from failing to comply with all applicable laws and regulations. Additionally linking information available between the agencies would further assist in allowing the public to assess oil and gas activity in the State.

The process of contacting and obtaining and reviewing information from these agencies can be time consuming and involve large numbers of complex, technical documents, and even then may not lead to getting information needed to assess oil and gas operations.

NMED. In order to obtain most documents regarding air permits for oil and gas facilities, you must submit a PRA to NMED. This involves first identifying the information not available through the agency's website, then filling out a form online, emailing it to NMED, and waiting for 2 weeks or more for a response.

NMED. While NMED's responses in our interactions were prompt, we often received a large amount of documents that would be nearly impossible to sort through by hand. Therefore, our research relied on a computer-based coding script to look through these documents for us, but not everyone has access to these kinds of automated data analysis techniques.

NMED. Furthermore, NMED stated in an email that they do not require companies applying for a facility permit to submit well information. This means NMED has no way of tracking which wells are associated with which facilities, which is a key component in tracking potential violations of state or federal law.

OCD. OCD maintains an online database of wells with all related documents, including permits to drill. While the data can be difficult to sort through or review given the large number of entries, this is a good step towards ensuring information is available to the public.

OCD. Unfortunately, while OCD also maintains a database of facilities, the data set is not comprehensive -- only facilities that have environmental issues (e.g. spills) are included. And OCD does not track which facilities are associated with the wells it permits, again making it difficult to identify or track potential violations of state or federal law.

Ultimately, a unified database of all permitting documents for both wells and facilities, as well as records of enforcement and other actions, would provide the most accessible tool for community activists. This database would require agency collaboration between NMED and OCD, and could potentially make it easier for the agencies themselves to ensure compliance.

Since much of New Mexico's oil and gas development occurs on Tribal lands, a joint management of this database between state agencies and Tribal governments could allow for better management of these sites. Currently, NMED has established a Tribal liaison position within their department in accordance with New Mexico's State-Tribal Collaboration Act. The Tribal liaison serves to provide direct communication between Tribal governments and the department. This liaison could assist in the management of a joint database.

While government enforcement often falls short, many Indigenous activists and community groups continue to organize and fight against the degradation of their land, natural resources, cultural centers, and community health. Grassroots organizations such as the San Juan Citizens Alliance, the Frack Off Chaco Coalition, Diné-Care, the Red Nation and Tewa Women United have been at the forefront demanding justice against the hazards imposed on them by the oil and gas industry. It is only through the recognition, protection, and inclusion of Indigenous Nations that environmental concerns can be appropriately dealt with.

Although agencies are **required by law** to consult with Tribal liaisons, the definition of what constitutes a proper consultation varies. Different agencies have used the loose term to **avoid meaningful consultation with tribes and take tribes' words into account.**

COVID-19 and the Navajo Nation

Photo by Kristin Murphy

During the COVID-19 pandemic, the federal government has ***continued to move forward with an amendment that would allow for land in the Chaco region to be leased for up to 3,101 new wells,*** *many of which will be fracking wells.*

The Navajo Nation has been shaken by the COVID-19 pandemic. In May 2020, the Nation surpassed New York and New Jersey to have the highest COVID-19 infection rate per capita in the U.S. This spread of infection is underpinned by a historical lack of adequate access to healthcare and basic amenities, like clean, reliable water. Furthermore, the close proximity of Navajo communities to oil and gas activity and its pollution may be linked to worse healthcare outcomes related to the disease -- a recent Harvard study has linked higher COVID-19 death rates to living in areas with higher pollution.

During the COVID-19 pandemic, the federal government has continued to move forward with the Mancos-Gallup Amendment -- an amendment to the regional resource management plan that would allow for land in the Greater Chaco region to be leased for up to 3,101 new wells, many of which will be fracking wells.

Throughout May 2020, the Bureau of Land Management and the Bureau of Indian Affairs held virtual meetings discussing the Mancos-Gallup Amendment. Indigenous community members expressed that these meetings were not suitable, as Tribal members who will be affected by the amendment often have limited or no internet access and therefore are not able to meaningfully participate in the public process. Tribal leadership has expressed that they are unable to adequately review the Amendment and attend meetings due to time-consuming emergency relief efforts. Despite the Navajo Nation's request for a pause on a public comment period, the Bureau of Land Management has ultimately moved forward with public comments with a 120-day extension, leaving the comment period open until September 25, 2020.

If this Amendment comes to pass, the sacred sites of the Chaco region will be threatened by an expansion of drilling in an area that has already endured decades of significant environmental damage. The Navajo Nation, already devastated by a century of drilling and the COVID-19 pandemic, will be further at risk of health complications resulting from oil and gas operations.

As part of our research, we had intended to travel to New Mexico in March 2020 to speak directly with Navajo Tribal members to learn more about their experiences with oil and gas drilling in the region. Unfortunately, this trip was cancelled as a result of the COVID-19 pandemic.

We have since decided to use a portion of our original travel funds to provide hand sanitizer and medical face shield masks to the Navajo Nation through the **Far East Navajo COVID-19 Response Fund,** organized in coordination with the Torreon Community Alliance.

Glossary

Terms and Definitions

Criteria pollutants	Common air pollutants that cause harm to human health and the environment; pollutants that are regulated through federally imposed national air quality standards
Energy Sacrifice Zones	Geographic area deemed appropriate for resource extractive activities to occur; most often resided by low income people of color
Grassroots movement	Organization often composed of community members to push changes on the social, environmental, institutional (and more) fabric of a society
Oil Facility	All of the equipment that processes and treats the oil pumped by oil wells so that it is ready for use
Oil Well	A boring in the Earth that is designed to bring petroleum oil hydrocarbons to the surface
Slurry	Semi-liquid mixture, typically composed of fine particles of manure, cement, or coal suspenses in water; in fracking, this is often composed of toxic chemicals injected underground to retrieve oil and gas
Spud date	The day of the very beginning of drilling a new oil well

Acronyms

IoES	Institute of the Environment and Sustainability
MST	Major Source Threshold
NCBI	National Center for Biotechnology Information
NMED	New Mexico Environment Department
NOI	Notice of Intent
OCD	Oil Conservation Division
US EPA	United States Environmental Protection Agency
VOC	Volatile organic compounds
WEG	WildEarth Guardians

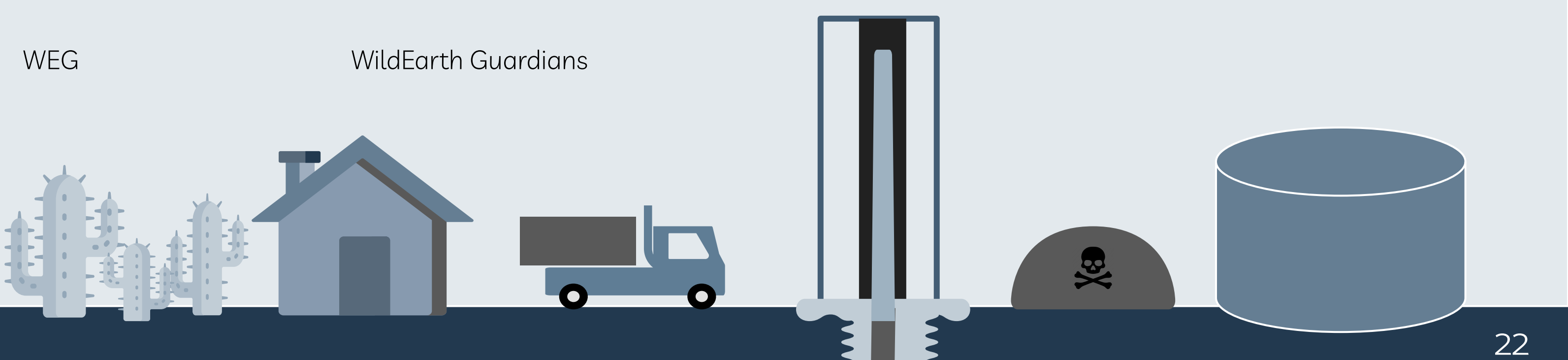


Photo by iStock/Getty

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