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STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

STATEMENT OF REASONS AND FINAL ORDER

This matter comes before the New Mexico Environmental Improvement Board (the "Board") upon a petition filed by the New Mexico Environment Department ("NMED" or "Department") proposing adoption of 20.2.50 NMAC ("Part 50"), which sets forth standards to regulate ozone precursor pollutants from the oil and gas sector. The Board voted to adopt Part 50 for the reasons that follow:

STATEMENT OF REASONS

I. PROCEDURAL BACKGROUND

1. On May 6, 2021, the Department filed its Petition for Regulatory Change ("Petition") with the Board requesting that the Board adopt new air quality regulations to be codified at 20.2.50 NMAC addressing emissions of ozone precursor pollutants from oil and gas sources in New Mexico under the Board's jurisdiction. The Petition also requested that the Board set a hearing on Part 50, assign a Hearing Officer to oversee the hearing process, and set a schedule for submission of pre-filed technical testimony.

2. The Department filed a Notice of Compliance with the Small Business Regulatory Relief Act on May 6, 2021.

3. On June 8, 2021, the Board issued its Order of Hearing Determination and Hearing Officer Appointment, setting a hearing on Part 50 to begin on September 20, 2021, and setting a schedule for filing of written direct and rebuttal technical testimony.

4. The following parties entered appearances in the rulemaking proceeding: Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, 350 New Mexico, and 350 Santa Fe (collectively "Clean Air Advocates" or "CAA"); Environmental Defense Fund ("EDF"); the New Mexico Oil and Gas Association ("NMOGA"); Oxy USA Inc. ("Oxy USA"); Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC (collectively "Kinder Morgan"); NGL Energy Partners LP, Solaris Midstream, LLC, OWL SWD Operating LLC, and Goodnite Midstream, LLC, and 3 Bear Delaware Operating - NM, LLC (collectively the "Commercial Disposal Group" or "CDG"), The Gas Compressor Association ("GCA"), the Independent Petroleum Association of New Mexico ("IPANM"); the New Mexico Environmental Law Center ("NMELC"); Center for Civic Policy and NAVA Education Project (collectively "CCP/NAVA"); the National Park Service; Solar Turbines; and WildEarth Guardians ("WEG").

5. Petitioner NMED was represented by counsel Lara Katz and Andrew P. Knight of the NMED Office of General Counsel.

6. Regarding the constituent entities that have appeared as Clean Air Advocates: Conservation Voters New Mexico ("CVNM") is a statewide, nonpartisan nonprofit committed to engaging the people of New Mexico in its long-standing shared values of protecting our air, land, water and the health of our communities. Diné C.A.R.E. is located on the Navajo Nation and is a nonprofit organization that works with many Navajo communities affected by energy and environmental issues. Earthworks is a nonprofit organization dedicated to protecting communities and the environment from the adverse impacts of mineral and energy development while promoting sustainable solutions. The Natural Resources Defense Council ("NRDC") is a nonprofit

organization that works to safeguard the earth—its people, its plants and animals, and the natural systems on which all life depends. NRDC has over 10,000 members and activists in New Mexico. San Juan Citizens Alliance ("Alliance") is a nonprofit organization with approximately 1,000 members that advocates for clean air, pure water, and healthy lands – the foundations of resilient communities, ecosystems and economies in the San Juan Basin. The Sierra Club is a national nonprofit organization with 67 chapters and more than 837,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Club has approximately 10,000 members in New Mexico. 350 New Mexico is a nonprofit organization of 8,000 members dedicated to building an inclusive movement in New Mexico to prevent the worst effects of climate change and climate injustice. 350 Santa Fe is a nonprofit organization organized for the purpose of working to accelerate the transition away from fossil fuels and collaborating, coordinating, and cooperating with climate crisis fighters in and around Santa Fe, while supporting climate protection through legislative and administrative initiatives. The CAA were represented by counsel Tannis Fox of Western Environmental Law Center and David R. Baake of Baake Law.

7. Environmental Defense Fund ("EDF") is a national membership organization with more than 2.5 million members residing throughout the United States and more than 18,000 residing in the state of New Mexico, many of whom are deeply concerned about the pollution emitted from oil and natural gas sources. EDF brings a strong commitment to sound science, collaborative efforts with industry partners, and marketbased solutions to our most pressing environmental and public health challenges. EDF was represented by Elizabeth Delone Paranhos

of Delone Law, Inc.

8. The New Mexico Oil and Gas Association ("NMOGA") comprises over 1000 operators who are engaged in the oil and gas business in New Mexico. Together they represent more than 90 percent of the total oil and gas activity in New Mexico. NMOGA established a working group with over 80 member companies that provided expert support in many areas and participated in the rulemaking process before the Department. NMOGA was represented by counsel Eric L. Hiser and Brandon Curtis of Jordan Hiser & Joy, PLC, an Dalva L. Moellenberg of Gallagher & Kennedy, PA,

9. Oxy USA ("Oxy") is a subsidiary of Occidental Petroleum Corporation which is an international energy company with assets in the United States, Middle East, Africa and Latin America. Oxy is one of the largest oil producers in the United States and is a leading producer in the Permian Basin. Oxy is the second largest oil and gas producer in the state. Oxy was represented by counsel J. Scott Janoe of Baker Botts, LLP.

10. Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC (collectively, "Kinder Morgan") provide energy transportation and storage services. In New Mexico, Kinder Morgan operates approximately 3,595 miles of transmission pipelines and own assets in 23 counties. Kinder Morgan delivers pipeline quality natural gas to local distribution companies—the city gates for the distribution of natural gas for use in people's homes for heating, stoves, water heaters, and other essential uses—and to industrial end users. Kinder Morgan was represented by counsel Ana Maria Gutierrez of Hogan Lovells US, LLP.

11. NGL Energy Partners LP, Solaris Midstream, LLC, OWL SWD Operating LLC, and Goodnite Midstream, LLC, and 3 Bear Delaware Operating - NM, LLC (collectively the

"Commercial Disposal Group" or "CDG") each have commercial operations in New Mexico for the recycling and underground injection of produced water. Members of the Group either conduct pipeline pig launching and receiving operations or could be affected by the proposed pigging rules in the future. The Commercial Disposal Group's members all have commercial saltwater disposal operations in the state of New Mexico that provide environmental services to the exploration and production ("E&P") sector of the oil and gas industry through recycling and/or underground injection of produced water. CDG were represented by counsel Christopher J. Neumann, Gregory R. Tan, and Casey Shpall of Greenberg Traurig, LLP, and Matthias L. Sayer of NGL Energy Partners, LP. 3 Bear Delaware Operating – NM, LLC was represented by Christopher L. Colclasure of Beatty & Wozniak, PC.

12. The Gas Compressor Association ("GCA") is an association whose members include owners and operators of significant fleets of engine-driven natural gas compressors that are utilized to provide compression services to producers and midstream companies within the oil and gas industry in New Mexico and throughout the United States. The GCA was represented by counsel Stuart R. Butzier and Chrstina C. Sheehan of Modrall Sperling Roehl Harris & Sisk, PA, and Jeffrey Holmstead, Tim Wilkins, and Whit Swift of Bracewell, LLP.

13. The Independent Petroleum Association of New Mexico ("IPANM") is a non-profit 501c(6) that serves as the voice of the independent oil and gas producers in New Mexico, and advances and preserves the interests of independent oil and gas producers while educating the public to the importance of oil and gas to the state and all our lives. IPANM members range from small, independent oil and gas producers (upstream) to small, independent pipeline workers and production site transportation employees (midstream), to independent marketers, consultants, and bankers (downstream). IPANM was represented by counsel Louis W. Rose, Kari Olsen, and

Ricardo S. Gonzales of Montgomery & Andrews, PA.

14. The New Mexico Environmental Law Center ("NMELC") is a nonprofit, public interest law firm that provides free and low-cost legal services on environmental matters throughout New Mexico. Founded in 1987, the Law Center works with clients – often individuals, neighborhood associations, environmental organizations, Tribes and Pueblos – seeking to protect the environment. The NMELC was represented by counsel Charles de Saillan.

15. The Center for Civic Policy ("CCP") is a New Mexico nonpartisan tax-exempt 501(c)(3) organization that works to empower and amplify the voices of everyday New Mexicans, especially those who experience oppression, in collaborations with local and national partners to incubate campaigns and foster strategic partnerships to achieve a more just and equitable New Mexico. NAVAEP is a grassroots nonprofit organization that promotes awareness and action on issues facing Native American communities and is committed to social, economic, and environmental justice principles that advance healthy and sustainable communities for Native families living in New Mexico. CCP and NAVA (collectively "CCP/NAVA") were represented by Professor and Supervising Attorney Gabriel Pacyniak, and Clinical Law Students Daniel Jaynes, Keifer Johnson, and Travis Shimanek.

16. The National Park Service representatives participating were John Vimont, Air Resources Division Chief, and Lisa Devore, Intermountain Region Air Quality Specialist.

17. Solar Turbines is a manufacturer of industrial combustion turbines (1000-32,000 hp). Solar's fleet includes more than 16,000 combustion turbines over 100 countries. The domestic fleet consists of over 8000 combustion turbines in power generation, pipeline compressor, and mechanical drive applications. Solar Turbines participated through Leslie Witherspoon.

18. WildEarth Guardians ("WEG") is a nonprofit conservation organization whose

mission is to protect and restore the wildlife, wild places, wild rivers, and health of the American West. WEG was founded in Santa Fe in 1989 and hosts offices in Denver, Missoula, and Portland. WEG was represented by counsel Matthey A. Nykiel and Daniel L. Timmons.

19. The parties filed written direct technical testimony and exhibits on July 28, 2021.

20. On August 26, 2021, the Hearing Officer issued a Procedural Order governing the submission of rebuttal testimony and the conduct of the hearing.

21. The parties filed written rebuttal testimony and exhibits on September 7, 2021.

22. The Board held a public hearing beginning on September 20, 2021, and ending on October 1, 2021.

23. The hearing was conducted virtually due to the COVID-19 pandemic. The public had ample opportunity to participate in the hearing.

24. Notice of the hearing was provided in accordance with Section 74-2-6 of the AQCA, Section 14-4-5.2 of the New Mexico State Rules Act, and the Board's Rulemaking Procedures at 20.1.1.301 NMAC. *See* NMED Exhibit 111 (Supplemental Direct Testimony of Elizabeth Bisbey Kuehn – Public Notice); NMED Exhibit 112 (EIB 21-27 (R) - Notice of Rulemaking Hearing – Ozone Precursor Rules (English)); NMED Exhibit 113 (EIB 21-27 (R) - Notice of Rulemaking Hearing – Ozone Precursor Rules (Spanish)); NMED Exhibit 114 (Affidavit of Publication – New Mexico Register Issue 12 (June 22, 2021)); NMED Exhibit 116 (Affidavit of Publication – Albuquerque Journal (English) (June 22, 2021)); NMED Exhibit 117 (Affidavit of Publication – Albuquerque Journal (Spanish) (June 22, 2021)); NMED Exhibit 118 (Affidavit of Publication – Carlsbad Current Argus (English) (June 22, 2021)); NMED Exhibit 119 (Affidavit of Publication – Carlsbad Current Argus (Spanish) (June 22, 2021)); NMED Exhibit 120 (Affidavit of Publication – Farmington Daily Times (English) (June 22, 2021)); NMED Exhibit 121

(Affidavit of Publication – Farmington Daily Times (Spanish) (June 22, 2021)); NMED Exhibit 122 (Affidavit of Publication – Hobbs Daily News Sun (English) (June 22, 2021)); NMED Exhibit 123 (Affidavit of Publication – Hobbs Daily News Sun (Spanish) (June 22, 2021)); NMED Exhibit 124 (Affidavit of Publication – Santa Fe New Mexican (June 22, 2021)).

25. Notice of the hearing was also posted on the New Mexico Sunshine Portal, and sent to New Mexico Tribes and the New Mexico Land Grant Council. *See* NMED Exhibit 115 (Posting of Notice of Rulemaking on New Mexico Sunshine Portal (June 22, 2021)); NMED Exhibit 125 (Notice of Rulemaking Hearing sent to New Mexico Tribes (June 22, 2021)); NMED Exhibit 126 Notice of Rulemaking Hearing sent to New Mexico Land Grant Council (June 22, 2021)).

26. At the hearing, all interested persons were given a reasonable opportunity to submit data, views or arguments orally and in writing and to examine witnesses testifying at the hearing.

27. The Board deliberated on March 10 and 11, 2022 and continued deliberations on April 11, 12, and 13, 2022. The Board reopened deliberations at its regularly noticed May 27, 2022 meeting for the limited purpose of addressing the requirement at NMSA 1978, § 74-2-5 of the Air Quality Control Act that the Board adopt a plan to control emissions of ozone precursor pollutants and other outstanding matters necessary to finalize this Statement of Reasons.

II. THE BOARD'S STATUTORY MANDATE TO ADDRESS OZONE UNDER THE NEW MEXICO AIR QUALITY CONTROL ACT

28. The Board is authorized to adopt Part 50 pursuant to the New Mexico Air Quality Control Act, NMSA 1978, Sections 74-2-1 to -17 ("AQCA"). Section 74-2-5(A) of the AQCA provides that the Board "shall prevent or abate air pollution." Section 74-2-5(B)(1) states that the Board shall "adopt, promulgate, publish, amend, and repeal rules and standards consistent with the Air Quality Control Act to attain and maintain national ambient air quality standards and prevent or abate air pollution . . . ." The AQCA defines "air pollution" as

> the emission, except emission that occurs in nature, into the outdoor atmosphere of one or more air contaminants in quantities and of a duration that may with reasonable probability injure human health or animal or plant life or as may unreasonably interfere with the public welfare, visibility or the reasonable use of property.

NMSA 1978, § 74-2-2(B). "Air contaminant" is defined as "a substance, including any particulate matter, fly ash, dust, fumes, gas, mist, smoke, vapor, micro-organisms, radioactive material, any combination thereof or any decay or reaction product thereof." NMSA 1978, § 74-2-2(A).

29. The AQCA also contains provisions that specifically authorize the Board to adopt regulations to ensure attainment and maintenance of the ozone NAAQS. Section 74-2-5(C) of the AQCA mandates that the Board take action to control VOC and NOX emissions when the Board determines that emissions from sources within its jurisdiction cause or contribute to ozone concentrations in excess of ninety-five percent of the ozone NAAQS. Under this statutory provision, the Board "shall adopt a plan, including rules, to control emissions of oxides of nitrogen, or NO_X, and volatile organic compounds, or VOCs, to provide for the attainment and maintenance of the standard." NMSA 1978, § 74-2-5(C).

III. SUBSTANTIVE BACKGROUND OF PROPOSED PART 50

A. Pre-Petition Public and Stakeholder Outreach

30. The proposed regulation is part of two significant environmental initiatives in New Mexico. The first is the Department's Ozone Attainment Initiative ("OAI"), which is aimed at ensuring that the State is able to maintain compliance with the National Ambient Air Quality Standards ("NAAQS") for ozone. The second initiative is pursuant to Governor Michelle Lujan Grisham's Executive Order 2019-003, which directs NMED and the New Mexico Energy, Minerals, and Natural Resources Department ("EMNRD") to "jointly develop a statewide,

enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources." NMED Exhibit 5 (Direct Testimony of Elizabeth Bisbey-Kuehn – public and stakeholder outreach on Part 50), pp. 2, 5-6.

31. Regulations developed under the OAI to reduce emissions of ozone precursor pollutants will have the co-benefit of reducing methane emissions because methane is released along with volatile organic compounds in oil and gas operations. Thus, the Department worked in close coordination with EMNRD in developing Part 50, and the agencies endeavored to align their respective regulatory regimes as much as possible to avoid duplicative or conflicting requirements. Id. at 2.

32. Beginning in the summer of 2019, the Department began an extensive stakeholder and public outreach process for the OAI and the NMED/EMNRD joint Methane Strategy. In June through August of 2019, NMED and EMNRD held numerous meetings throughout the State to provide information regarding the need for the regulatory initiatives and the relevant authorities for the regulatory actions; to hear input from stakeholders and members of the public; and to answer questions regarding the rulemaking process. Id. at 3-6.

33. The agencies also convened a Methane Advisory Panel ("MAP"), consisting of technical stakeholders focusing on processes and equipment associated with oil and gas exploration, production, gathering, and processing. The MAP was comprised of 27 members with expertise in various parts of the oil and gas industry, and included local and national environmental nongovernmental organizations as well as major and independent industry representatives from the upstream and midstream sectors. Additional expertise was provided by representatives from Los Alamos National Laboratory, Colorado State University, and the New Mexico Institute of Mining and Technology. The MAP met every other week over a four-month period and covered

technical topics related to controlling volatile organic compounds ("VOC") and methane emissions from equipment and operations employed in the oil and natural gas sector. Draft topic reports and all meeting presentations from the MAP meetings were posted online on both agencies' websites. In December of 2019, the MAP released a technical report for public review and input, and the agencies accepted comments on the report through February 20, 2020. Id. at 4-5.

34. On July 20, 2020, NMED released a preliminary draft of its ozone precursor regulation for the purpose of soliciting public and stakeholder input. In August of 2020, the Department met with stakeholder groups and held a public listening session during which participants were encouraged to provide both verbal and written feedback. The Department accepted written comments on the preliminary draft through September 20, 2020. A total of 524 written comments were received during the two-month comment period. From September 2020 through May 2021, the Department reviewed the input received from stakeholders and the public, and made substantial revisions to the regulation based on that input. Id. at 7.

B. Fundamentals of Ozone

35. Ozone is a molecule composed of three oxygen atoms (O3) and is the main component of smog. *See* NMED Exhibit 106, p. 4.

36. Ozone occurs in both the Earth's upper atmosphere (stratospheric ozone) and at ground-level (tropospheric ozone). Stratospheric ozone in the upper atmosphere is good ozone because it shields us from harmful ultraviolet rays from the sun. However, ozone at ground-level is harmful to human health and the environment. NMED Exhibit 13 (Raso Direct Testimony), pp. 1-2; NMED Exhibit 106, p. 4.

37. Elevated levels of ground-level ozone can cause breathing difficulties, coughing and scratchy throat, aggravate lung disease such as asthma, emphysema and chronic bronchitis and

make the lungs more susceptible to infection. Ozone can also harm plants, especially during the growing season, and cause material damage. NMED Exhibit 1 (Direct Testimony of Michael Baca), p. 2; NMED Exhibit 106, p. 4.

38. Ozone is not directly emitted but instead is formed in the atmosphere through a set of complex photochemical reactions involving volatile organic compounds ("VOC") and oxides of nitrogen ("NOX") in the presence of sunlight. Elevated ozone concentrations typically occur on hot summer days under low wind speed and/or ground-level trapping inversions that allow VOC and NOX concentrations to build up. NMED Exhibit 13 (Direct Testimony of Angela Raso), pp. 2-3; NMED Exhibit 106, pp. 4-5.

39. NOX emissions are produced by combustion where the heat converts the naturally occurring nitrogen and oxygen in the air to NOX emissions. NOX is primarily produced by anthropogenic (man-made) sources through fuel combustion of coal, gasoline, diesel, oil, natural gas, and biomass burning. Natural sources of NOX include wildfires, lightning, and soils. NMED Exhibit 13, pp. 2-3; NMED Exhibit 106, pp. 5.

40. Anthropogenic sources of VOC include mobile sources, chemical plants and refineries, oil and gas production, consumer products and other sources. On a region-wide basis, biogenic VOCs from plants are the largest VOC contributor, but in locations of large amounts of anthropogenic VOC emission sources, such as urban areas, oil and gas production fields or industrial complexes, biogenic VOC may not be the largest source sector. NMED Exhibit 13, pp. 2-3; NMED Exhibit 106, p. 5.

41. Emission control plans designed to mitigate high ozone concentrations, such as the Department's Ozone Attainment Initiative and Part 50, reduce anthropogenic VOC and/or NOX emissions. NMED Exhibit 106, p. 5.

42. Ozone formation can be more sensitive to NOx or VOC emissions, but usually has some sensitivity to both ozone precursors. NMED Exhibit 106, pp. 5-6.

C. Regulation of Ozone under the Clean Air Act

43. The federal Clean Air Act ("CAA") requires the U.S. Environmental Protection Agency ("EPA") to set National Ambient Air Quality Standards ("NAAQS") for pollutants that EPA determines are harmful to public health and the environment. *See* 42 U.S.C. § 7408. These standards are in the form of maximum allowable concentrations in the ambient air during a specified time period and are designed to protect the most sensitive individuals from harm from airborne pollutants. The CAA identifies two sets of NAAQS to accomplish this: Primary standards provide public health protection, including protecting the health of vulnerable populations such as asthmatics, children, and the elderly; Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Id at § 7408(b). NMED Exhibit 1, p. 1.

44. The EPA has set NAAQS for six principal pollutants, known as "criteria" air pollutants: ozone, nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter 10 microns or less, particulate matter 2.5 microns or less, and lead. *See* 40 C.F.R. Part 50. The CAA requires EPA to review the standards on a periodic basis, which may result in the standards being revised based on health and environmental criteria that apply to the concentration of a pollutant in outdoor air to limit harmful exposures and detrimental effects. 42 U.S.C. § 7409(d). NMED Exhibit 1, p. 2.

45. The primary ozone NAAQS are set to protect people most at risk from breathing ozone in the ambient air, including asthmatics, children, older adults and people who are active outdoors, such as workers. Children are at greatest risk from ozone exposure because their lungs

are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Some of the health problems caused by ozone include coughing, sore throat, difficulty breathing, inflammation and damage to airways, increased frequency of asthma attacks, and aggravation of lung diseases such as asthma, emphysema and chronic bronchitis. *See* NMED Exhibit 3 – EPA Integrated Science Assessment ("ISA") for Ozone and Related Photochemical Oxidants, Executive Summary (April 2020); *see also* 85 Fed. Reg. 87256, 87268-87275. NMED Exhibit 1, p. 2.

46. Air quality management agencies use data from monitors to calculate a "design value" to determine an area's compliance status with the NAAQS. The design value represents the metric used to compare monitoring data to the level specified by the standard. *Id.* at p. 3.

47. Following promulgation of a new or revised NAAQS, EPA undertakes a process of designating all areas within each state as in attainment, nonattainment, or unclassifiable for the standard. *See* 42 U.S.C. § 7407(d). This process entails collaborating with states and tribes and considering their recommendations, including proposed nonattainment boundaries based on data and information from air quality monitors or modeling. If the concentrations of a criteria pollutant in a geographic area meets or fall below the NAAQS, the area is designated as in "attainment" of the standard. Areas that exceed the NAAQS are designated as "nonattainment" areas. Areas that do not have monitoring data available are designated as "attainment/unclassifiable" or "unclassifiable". EPA is required to designate areas of the States within two years of promulgating a new or revised NAAQS. *See* 42 U.S.C. § 7407(d). NMED Exhibit 1, p. 3.

48. In October 2015, following a periodic review, EPA revised the ozone NAAQS downward from 0.075 parts per million (ppm) to 0.070 ppm. *See* 80 Fed. Reg. 65291. For the 2015 ozone NAAQS, all states were required to submit their designation recommendations to EPA by

October 1, 2016. Ozone data collected by NMED from 2014 through 2016 indicated that a monitor located in the Sunland Park area in southern New Mexico was registering ozone concentrations above the NAAQS. NMED submitted a nonattainment area recommendation for the Sunland Park area and recommended attainment or attainment/unclassifiable designations for the remainder of New Mexico. EPA concurred with the recommendations and finalized the area designations for New Mexico on August 3, 2018. *See* 83 Fed. Reg. 25776. NMED Exhibit 1, p. 3.

49. On December 23, 2020, EPA retained the existing 2015 ozone NAAQS. *See* 85 Fed. Reg. 87256. The CAA does not require EPA to promulgate area designations when an existing NAAQS is retained following the periodic review process. In line with this and historical practice, EPA did not designate new nonattainment areas following this periodic NAAQS review. However, the current EPA administration has indicated that it intends to revisit the review process, including the available scientific evidence and exposure/risk information, to assess the adequacy of public health and welfare protection provided under the current NAAQS. NMED Exhibit 1, p. 4.

50. Ozone monitoring data for 2018-2020 indicate that other areas of the state are approaching or violating the 2015 ozone NAAQS. In particular, Eddy County and sites in southern Doña Ana County are monitoring ozone levels in violation of the NAAQS, while San Juan, Lea, Santa Fe, Sandoval and Valencia Counties are within 95% of the standard. Additionally, oil and gas sources located in Rio Arriba and Chaves Counties contribute to elevated ozone concentrations in the San Juan and Permian Basins, respectively. NMED Exhibit 1, p. 4.

51. There are costs associated with a nonattainment designation. Such a designation triggers planning and permitting requirements, including emissions inventories, transportation conformity, reasonable further progress, permitting offsets, and lowest achievable emissions rates for equipment. These requirements are time consuming and costly to both industry and the

Department, and can result in competitive disadvantages to New Mexico businesses and communities. Further, a nonattainment designation entails a classification level based on the severity of violation of the NAAQS. Each level of classification carries an escalating series of requirements and consequences. Thus, incremental reductions in ozone concentrations can mean a less severe nonattainment classification, which in turn can result in lower costs and burdens on industry and regulatory agencies in New Mexico resulting from mandatory measures to address violations of the NAAQS. Tr. Vol. 1, 251:7 – 253:4.

D. Ozone Monitoring and Design Values

The NMED Air Monitoring Network

52. Witness Brent Ellington testified on behalf of the Department regarding ozone monitoring, methods and procedures, and federal requirements for monitoring equipment. Mr. Ellington is an Environmental Scientist Specialist with the Ambient Air Monitoring Section of the NMED Air Quality Bureau. NMED Exhibit 27, p. 1 (Direct Testimony of Brent Ellington).

53. The Department is responsible for collecting ambient air data to document present air quality and significant trends in pollutant concentrations. The data collected is used to determine the State's status with regard to compliance with federal NAAQS. *Id.* at p. 1-2.

54. For purposes of ozone monitoring for compliance with the NAAQS, New Mexico is broken down into eight Air Quality Control Regions ("AQCRs") located in 33 counties covering a total area of 120,000 square miles. The existing NMED Air Monitoring Network includes monitors in the areas of highest population density: Doña Ana, Santa Fe, and Sandoval Counties. The monitors in the network are sited to determine the impact on ambient pollution levels of significant sources and source categories, in particular those in San Juan County, a region of concentrated energy development and generation. The network includes sites that measure general

background concentrations, including sites in San Juan County and in Carlsbad, La Union, and Santa Teresa. The purpose of the network is to support the NAAQS, and the Bureau is designated by EPA to operate the monitors. *Id.* at p. 2.

55. The locations of the monitors in the NMED Air Monitoring Network meet the general ambient monitoring site types specified in the U.S. Environmental Protection Agency's ("EPA") regulations at 40 C.F.R. Parts 53 and 58. *Id.* at p. 3.

56. Ambient air data collected by the Bureau is submitted to EPA for inclusion in the Air Quality System ("AQS") and is used to determine compliance with state and federal air quality regulations. *Id.* at p. 4.

Calculation of Design Values

57. Witness Andrew Ahr testified on behalf of the Department regarding how design values for ozone are calculated, quality assurance ("QA") of the data, and how the data is submitted to EPA. Mr. Ahr is the Quality Assurance Staff Manager for the NMED Air Quality Bureau. NMED Exhibit 30, p. 1.

58. A design value is a statistic that describes the air quality status of a given location relative to the level of the NAAQS. Design values are typically used to designate and classify nonattainment areas, as well as to assess progress towards meeting the NAAQS. *Id*. at p. 1-2.

59. Design values are computed and published annually by EPA's Office of Air Quality Planning and Standards, and reviewed in conjunction with the EPA Regional Offices. *Id.* at p. 2.

60. The primary and secondary NAAQS for ozone are met at an ambient air monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration (i.e., the design value) is less than or equal to 0.070 ppm. This ozone design value has been in effect since October 26, 2015. *See* 40 C.F.R. Part 50, Appendix U. *Id.*

61. NMED collects and submits the required data to EPA on a quarterly basis. EPA then uses the data to calculate the 8-hour ozone concentrations for each day. *Id.* at p. 6.

62. From the 8-hour average ozone concentration data, the EPA determines the 1st, 2nd, 3rd and 4th highest daily maximum 8-hour ozone concentrations for the entire year. Design values are produced by the EPA based on the annual fourth-highest daily maximum 8-hour ozone concentration, averaged over three years, expressed in ppm. The 3-year average is computed using the three most recent, consecutive years of ambient ozone monitoring data. *Id.*

E. The Department's Ozone Attainment Initiative

63. As of the time of the filing of the Petition in this matter, seven monitors located in counties under the Board's jurisdiction were registering ozone design values exceeding 95% of the NAAQS: San Juan, Santa Fe, Sandoval, Valencia, Eddy, Lea, and Doña Ana. Two other counties – Chaves and Rio Arriba – had oil and gas sources that were contributing to the ozone levels at these monitors. NMED Exhibit 1, p. 5.

64. To address the statutory requirement in Section 74-2-5(C) of the AQCA, the Department embarked upon the Ozone Attainment Initiative ("OAI") to develop a plan consisting of a series of mandatory rules and voluntary measures to mitigate emissions of NOX and VOCs in the aforementioned counties.

65. This rulemaking is the first of the mandatory rules being brought before the Board under the OAI. The Department intends to propose additional rules targeting other sectors. For instance, Section 177 of the Clean Air Act allows other states to adopt California's motor vehicle emission standards. The Department filed a rulemaking petition in December asking the Board to set a hearing to adopt regulations setting standards for low emission vehicles ("LEV"), and zero emission vehicles ("ZEV") for adoption in 2022 that will provide further mitigation of ozone

precursors. NMED Exhibit 1, p. 6.

66. The Department has also submitted a letter of participation to EPA for the Ozone Advance Program. The Advance Program is a means to promote local actions in areas designated as in attainment to reduce ozone levels for the continued maintenance of the NAAQS. The Department will coordinate efforts with local governments, industry, academia, and the public to take proactive steps towards the protection of air quality. In addition to positioning areas to avoid a nonattainment designation, the Advance Program can allow communities to choose control measures that are cost effective and that make the most sense for their area, potentially resulting in multi-pollutant benefits. *Id.;* Tr. Vol. 1, 248:22 – 251:6.

67. The Department has developed a path forward for its participation in the Ozone Advance program that outlines all the activities, programs, and control measures to be included as part of New Mexico's strategy to address rising ozone levels in the State in order to comply with the Clean Air Act. Tr. Vol. 1, 249:23 – 251:6.

68. The Board adopts the Ozone Path Forward, as set forth in NMED Exhibit 4 – Amended, as the plan required to satisfy the mandatory statutory directive to the Board under Section 74-2-5 of the AQCA.

F. Ozone Modeling for the OAI

Fundamentals of Ozone Modeling

69. Ozone modeling is usually conducted using a photochemical grid model ("PGM"). A PGM divides the region to be modeled into three-dimensional ("3-D") arrays of boxes (grid cells). NMED Exhibit 106 (Direct Testimony of Ralph Morris), p. 6.

70. There are three main inputs for a PGM: (1) 3-D meteorological fields that are usually produced by a prognostic meteorological model such as the Weather Research Forecast

model; (2) hourly speciated emission inputs that consist of gridded surface layer emissions that are emitted into layer 1 of the PGM (e.g., mobile sources and biogenic emissions) and point source emissions that are emitted in an appropriate upper layer grid cell of the PGM based on its plume rise (e.g., power plants and industrial point sources); and (3) Boundary Condition ("BC") species concentrations that are defined around the boundaries of the modeling domain (i.e., transport from outside of the PGM modeling domain). *Id.* at 6-7.

71. PGM emission inputs are prepared by processing county-level and point source emissions using an emissions model, such as the Sparse Matrix Operator Kernel Emissions ("SMOKE") modeling system. PGM boundary condition inputs are usually defined using output from a global chemistry model, such as GEOS-Chem. Unlike air quality dispersion models (e.g., AERMOD) that are applied for a single source or small group of sources, PGMs must include all sources of air pollution, and so are more intensive and costly to apply. *Id.* at 7.

72. A PGM will first be set-up for a historical base year, or in the case of an ozone modeling PGM application, an ozone season period of a past year. A PGM base year base case simulation is conducted that is subjected to a model performance evaluation ("MPE") that compares the modeled concentrations with concurrent observations. Graphical and statistical techniques are used in the MPE, the results of which are also compared to model performance goals and criteria based on past well-performing PGM applications to help put the PGM MPE in context. Diagnostic sensitivity tests may also be conducted to improve the PGM model performance through alternative model inputs or model options. *Id.* at 8.

73. A typical PGM application will then project the anthropogenic emissions to a future year with all other inputs typically held constant the same as used in the base year. Anthropogenic emissions are then controlled and future year PGM simulations made to determine the types and

levels of emissions controls required to meet certain air quality objectives, or the effects of regulatory emissions control requirements on ozone concentrations. *Id.*

PGM Modeling for the OAI

74. The Department contracted with a team consisting of the Western States Air Resource Council ("WESTAR") and Ramboll US Consulting, Inc. ("Ramboll") to conduct PGM modeling in support of the Department's Ozone Attainment Initiative ("OAI"). NMED Exhibit 106, p. 8.

75. Ralph Morris, Managing Principal of Ramboll's Environment and Health Central West Business Unit, testified on behalf of NMED regarding the modeling done by Ramboll for the Department's Ozone Attainment Initiative. *Id.*

76. Mr. Morris has over 40 years of air quality consulting experience, and is one of the original developers of many of the photochemical air quality models that are or have been used for regulatory decision making in the United States and around the world, including one of the leaders in the development of Ramboll's Comprehensive Air-quality Model with extensions ("CAMx"). CAMx is the model that was used to evaluate the ozone impacts of proposed Part 50. *Id.* at 1-3.

77. Mr. Morris has assisted EPA in developing air quality modeling techniques for over 30 years, which included addressing near-source, far-field and photochemical modeling issues. Currently, he is leading the air quality modeling efforts of the western states to develop their Regional Haze state implementation plans ("SIPs") due in July of 2021, and has just finished leading the air quality modeling efforts for the Denver Serious ozone SIP and starting the Denver Severe/Moderate ozone SIP modeling efforts under the 2008 and 2015 ozone national ambient air quality standards. *Id.*

78. The OAI PGM study was conducted from April 2020 to May 2021, with results and

progress of the study continuously documented on the wrapair2.org website as the study evolved. This included preparing a Modeling Protocol (Ramboll and WESTAR, 2020a) at the outset of the study (May 2020) that provided a roadmap for how the study would be conducted, and allow NMED and other interested parties to comment on the study approach prior to conducting the OAI PGM study. *Id.* at 8.

79. The OAI PGM study used the Comprehensive Air-quality Model with extensions (CAMx) PGM on a 36/12/4-km grid resolution nested modeling domains shown in Figure 2 with the 4-km domain covering New Mexico and nearby regions (e.g., the San Juan and Permian oil and gas development regions). *Id.* at 9.

80. The CAMx 2014 36/12/4-km modeling platform was developed for the May-August 2014 base year period. The CAMx 2014 36/12/4-km modeling platform was based on the Western Regional Air Partnership ("WRAP") and Western Air Quality Study ("WAQS") CAMx 2014 36/12-km annual modeling platform. Boundary Conditions for the OAI PGM study CAMx 36/12/4-km simulation were based on output from the WRAP-WAQS 2014 GEOS-Chem global chemistry model simulation. The OAI study conducted two Weather Research Forecast ("WRF") 2014 36/12/4-km meteorological model simulations that differed in the analysis fields used to initialize, provide BCs, and used in the four-dimensional data assimilation ("FDDA") that nudges the WRF meteorological model predictions to the observations. *Id.*

81. A CAMx 2014v2 base case simulation and model performance evaluation was conducted and documented in an addendum to the 2014 base case modeling report and the OAI PGM study AQ Technical Support Document. *Id.* at 10.

82. A 2028 base case emissions scenario was developed that was based on the WRAP-WAQS 2028 on-the-books (2028OTBa2) scenario with updated 2028 New Mexico base case

O&G emissions. *Id.*

83. A 2028 oil and gas control strategy ("2028 O&G control strategy") scenario was developed that reduced the New Mexico 2028 base case O&G emissions accounting for the estimated effects of Part 50, as determined by Eastern Research Group ("ERG") under separate contract with NMED. *Id.*

84. CAMx 2028 base case and 2028 O&G control strategy simulations were conducted, and the resultant ozone estimates were analyzed to determine the effect that the requirements in Part 50 would have on ozone concentrations if implemented. Ozone source apportionment modeling for the 2028 O&G control strategy was also conducted. *Id.*at 10-11.

85. The modeling results estimated that the requirements of Part 50 would reduce projected 2028 future year ozone design values ("DVFs") at New Mexico monitoring sites by between -0.2 to -1.5 ppb (*see* Table 5 in Section IX). The largest reductions in 2028 ozone DVFs occurs at the Navajo Lake (-1.5 ppb) and Substation (-1.2 ppb) monitoring sites in San Juan County in the San Juan Basin. The largest reductions in 2028 ozone DVFs in the Permian Basin occur at the Hobbs monitor (-0.7 ppb) in Lea County and the Carlsbad monitor (-0.3 ppb) in Eddy County. *Id.* at 11.

86. The requirements of Part 50 are estimated to reduce daily MDA8 ozone concentrations across wide areas in New Mexico, with the largest ozone reductions occurring within the San Juan and Permian Basins. *Id.*

87. On some days there are also isolated areas of increases in ozone concentrations due to VOC and NO_X emissions reductions from Part 50 that are due to NO_X disbenefits, however the area of ozone increases are much less than the areas of ozone decreases, and the magnitudes of the ozone increases are also usually less than the magnitudes of the ozone decreases. *Id.* at 11-12.

88. Pursuant to EPA modeling guidance, Ramboll also made future-year ozone design value projections using an alternative to the base-year design value. Mr. Morris testified that this was justified given the increase in ozone design values over time. The projection was done using the three-year design value based on 2015 to 2019, which is the five-year period that encompasses the design value at the time the modeling was being performed. In this projection, Carlsbad and Eddy County monitors were above the ozone NAAQS in the 2028 base case. For the 2028 New Mexico control strategy, the design value was reduced from 71.2 ppb to 70.9 ppb. In other words, implementation of Part 50 reduced the design value from above the NAAQS to below the NAAQS. *Id.* at 46-48.

89. The modeling showed that emissions from oil and gas point and non-point sources constitute a substantial percentage of the New Mexico anthropogenic emissions contributions to ozone levels, including 55% at the Navajo Lake monitor near the San Juan Basin, and 71% at the Hobbs monitor near the Permian Basin. NMED Rebuttal Exhibit 11 (Rebuttal Testimony of Ralph Morris), pp. 4-6; Tr. Vol. 2, 375:5-17.

90. The conclusion of the OAI photochemical modeling study was that Part 50 will reduce ozone design values at monitored sites by as much as 1.5 ppb, and by as much as 3 ppb across New Mexico, with larger reductions in maximum daily eight-hour concentrations. Tr. Vol. 2, 376:13-25.

91. The modeling study showed that ozone formation in the majority of New Mexico is more NO_X sensitive, with the San Juan Basin being an exception. However, both pollutants contribute to ozone formation, and NO_X sensitivity does not mean that there will be no ozone reduction benefits from VOC emissions reductions, particularly in the San Juan Basin. NMED Rebuttal Exhibit 11, p. 8.

92. IPANM witness Doug Blewitt asserted that the OAI Air Quality Technical Support Document ("AQTSD") (NMED Exhibit 17) failed to document the 2028 future year emissions used. *See* IPANM Exhibit 6, pp. 9-12. Mr. Morris testified that the AQTSD noted that the 2028 emissions were based on the WRAP-WAQS 2028OTBa2 emissions inventory used in the western states Regional Haze SIPs, whose derivation and documentation are contained in numerous reports/studies/webpages cited in the NM OAI Study AQTSD that Mr. Blewitt could have accessed and reviewed for details on how the 2028 future year emissions were developed, as discussed below. Tr. Vol. 2, 377:16 – 378:4.

93. Mr. Blewitt testified that the OAI modeling should have been separated values between oil and gas VOC and NO_X controls so as to identify ozone benefits from NO_X control compared to VOC controls. Mr. Morris testified that such an approach is not typical when analyzing emission control strategies for ozone because many control measures result in both VOC and NO_X emission reductions (e.g., reducing hours of operation). Thus, obtaining separate ozone reductions for the VOC versus NO_X emission reductions does not make sense since the reduction of just one of the ozone precursors in isolation is not possible for some control measures. NMED Exhibit 11, pp. 11-12.

94. Mr. Blewitt testified that the effects of the controls in Part 50 on ozone concentrations shown by the model were not significant, and that Part 50 was "ineffective" at reducing ozone at monitors in the State. Mr. Morris testified that the reductions seen in the OAI modeling are typical for ozone modeling evaluating a single source sector control strategy such as Part 50, and that a 1.5 ppb reduction as shown in the OAI modeling for Part 50 is considered a good amount for such a strategy. He testified that the reductions in ozone concentrations that would result from Part 50 as shown by the modeling would be sufficient to make the difference between

an attainment and nonattainment designation, or a higher or lower nonattainment classification. He further testified that control strategies like Part 50 are shown to reduce ozone concentrations when implemented. NMED Rebuttal Exhibit 11, pp. 12-13; Tr. Vol. 2, 501:25 – 502:24.

95. NMOGA witness Dennis McNally stated that he "agree[d] with the general approach taken to examine the air quality impacts of the proposed rule." McNally Direct at p. 4. Mr. McNally also agreed with the AQTSD's conclusion that the model performance was as good or better than most recent photochemical modeling studies and "appears to be a reliable [photochemical grid model] modeling platform for evaluating emission reduction strategies for reducing ozone concentrations in New Mexico." *Id.* at p. 5.

96. Mr. McNally attempted to split out the oil and gas ozone contributions between VOC and NO_X. However, Mr. Morris demonstrated that Mr. McNally's approach increased uncertainties in the modeling. Tr. Vol. 2, 380:7-15; NMED Rebuttal Exhibit 11, pp. 6-8.

97. Mr. McNally testified that certain VOC controls could increase NO_X emissions, and that such NO_X disbenefits were not included in the OAI modeling. McNally Direct at p. 16. In response, ERG complied a revised control scenario estimating that NO_X emissions increases due to certain VOC controls (e.g., combustion of VOC emissions in flares) would result in increases in NO_X emissions of 67 tons per year ("tpy"). *See* NMED Rebuttal Exhibit 13. Mr. Morris estimated that the impacts of a 67 tpy increase in NO_X emissions would increase ozone by an order of a thousandth (0.001) of a ppb, and thus a 67 tpy increase in NO_X emissions due to the VOC controls would have no material effect on the ozone modeling results. NMED Rebuttal Exhibit 11, p. 10.

98. Witness Cindy Hollenberg testified on behalf of the Department regarding excess emissions from the oil and gas industry in New Mexico in recent years. Her testimony indicates

that the estimated baseline emissions used for the modeling are likely to be significantly underestimated because they assume that all sources are complying with existing permits and regulations. She further testified as to how the provisions of Part 50 will enhance compliance and reduce excess emissions, resulting in more reductions in emissions of ozone precursor pollutants. *See* NMED Rebuttal Exhibit 15 (Written Rebuttal Testimony of Cindy Hollenberg); Tr. Vol. 2, 531:21 – 532:3; 539:19 – 544:3, 555:17 – 557:2, 564:3 – 565:17.

99. The Board finds that the modeling conducted for the OAI provides a reliable basis for evaluating emission reduction strategies, such as proposed Part 50, for reducing ozone concentrations in New Mexico.

100. The Board further finds that the modeling demonstrates that oil and gas sources in Chavez, Doña Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia Counties in New Mexico are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the NAAQS.

G. Costs and Feasibility of Part 50

101. The State of New Mexico is obligated to comply with the federal ozone NAAQS pursuant to the Clean Air Act.

102. Where areas of a state are violating the NAAQS, EPA will designate those areas as nonattainment areas, and will classify each area based on the severity of nonattainment. Such federal designations and classifications require action on the part of states, and necessarily entail costs to industry and state regulatory agencies. Tr. Vol. 1, 251:7 – 252:17 (Baca).

103. In an attempt to proactively address the federal requirements for nonattainment designations, the AQCA mandates that the Board take action to address elevated ozone levels in the New Mexico, including regulations targeting NO_X and VOC emissions from sources that are

causing or contributing to elevated concentrations exceeding 95% of the NAAQS. Thus, the AQCA implicitly recognizes that there will be costs associated with the actions the Board is required to take. *Id.*

104. The proposed emissions standards and requirements in Part 50 are all based on existing regulatory standards and provisions adopted and implemented by other states (e.g., Colorado, Pennsylvania, Ohio, Wyoming) and the federal government (e.g., EPA's New Source Performance Standards ["NSPS"] and National Emissions Standards for Hazardous Air Pollutants ["NESHAP"]). *See generally* NMED Exhibit 32 (Direct Testimony of Elizabeth Bisbey-Kuehn and Brian Palmer).

105. The Department presented extensive testimony regarding the basis for each provision of the proposed rule, including detailed cost estimates presented in comprehensive spreadsheets, lengthy pre-filed written direct and rebuttal testimony, and oral surrebuttal testimony at the hearing. *See* Tr. Vol. 3, 757:11 – 758:3; NMED Exhibit 32; NMED Rebuttal Exhibit 1 (Rebuttal Testimony of Elizabeth Bisbey-Kuehn and Brian Palmer); NMED Exhibit 56 – ICE Reductions and Costs NO2 Spreadsheet; NMED Exhibit 57 – ICE Reductions and Costs VOC Spreadsheet; NMED Exhibit 58 – Turbines Reductions and Costs NO2 Spreadsheet; NMED Exhibit 59 – Turbines Reductions and Costs VOC Spreadsheet; NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet; NMED Exhibit 77 – Dehydrators Reductions and Costs VOC Spreadsheet; NMED Exhibit 82 – Heaters Reductions and Costs NO_2 Spreadsheet; NMED Exhibit 84 – Transfers Reductions and Costs VOC Spreadsheet; NMED Exhibit 95 – Pneumatics Reductions and Costs VOC Spreadsheet; NMED Exhibit 100 – Storage Tanks Reductions and Costs VOC Spreadsheet; NMED Rebuttal Exhibit 25 – Updated ICE Reductions and Costs NO_2 Spreadsheet; NMED Rebuttal Exhibit 26 – Updated Turbines Reductions and Costs NO_2

Spreadsheet; NMED Rebuttal Exhibit 27 – Updated Heaters Reductions and Costs NO_2 Spreadsheet; NMED Rebuttal Exhibit 28 – Updated Storage Tanks Reductions and Costs VOC Spreadsheet.

106. The Department estimated that the emission controls and associated requirements in Part 50 would result in total annual costs of $338 million/year. Tr. Vol. 3, 757:11 – 758:3; NMED Rebuttal Exhibit 20 – Total Cost Summary Spreadsheet.

107. The rule also contains numerous offramps for applicability of requirements based on potential to emit thresholds; qualification as a small business facility as defined under the rule; and opportunities to seek approval of alternative monitoring plans or submit technical infeasibility demonstrations. *See generally*, NMED Exhibit 32 (Kuehn-Palmer); NMED Rebuttal Exhibit 1 (Written Rebuttal Testimony of Elizabeth Bisbey-Kuehn and Brian Palmer – Provisions of Part 50).

108. Witness John Dunham, managing partner of New York-based consulting firm John Dunham & Associates (aka Guerilla Economics), provided testimony on behalf of NMOGA in this proceeding. Mr. Dunham was commissioned by NMOGA to evaluate the potential costs of Part 50 and perform an economic impact analysis of the effects of those costs. NMOGA Appendix A6, Testimony of John Dunham, at p. 1; NMOGA Appendix A, Memorandum by John Dunham & Associates dated June 13, 2021 ("JDA Analysis"), at p. 1.

109. Mr. Dunham estimated that the rule would cost approximately $3.8 billion over a five-year period. Based on this cost estimate, Mr. Dunham testified that his model showed that the state economy would face a $674.2 million loss, and state and local taxes would fall by nearly $22.9 million. He further estimated that 3,217 jobs would be lost in the state if the rule were implemented. NMOGA Appendix 6, JDA Analysis at pp. 7-10.

110. Mr. Dunham's analysis did not evaluate potential benefits of Part 50, such as improved human health from reduced pollution and additional captured hydrocarbons due to emissions controls. Tr. Vol. 3, 726:4 – 728:5.

111. Mr. Dunham testified that his analysis relied on data from a survey of ten unidentified oil and gas companies within NMOGA's membership to calculate the estimated equipment and operational costs of Part 50. *See* NMOGA Appendix 6, JDA Analysis, p. 7.

112. NMOGA did not provide the survey questions or any of the data that Mr. Dunham used for his analysis to the other parties or the Board, nor did they provide the modeling files for the model. NMOGA claimed that this is because the data is proprietary. Tr. Vol. 3, 731:25 – 733:4.

113. Mr. Dunham's analysis did not include any basic information on the ten companies that were surveyed that would allow other parties to determine whether and to what extent those companies are representative of the industry in New Mexico. Mr. Dunham testified that he did not know any such information about the surveyed companies that provided the data upon which he based his analysis. Tr. Vol. 3, 723:2-19.

114. On cross-examination, Mr. Dunham agreed that it is difficult to evaluate an economic analysis when one does not have access to the data that was used as the basis for that analysis. Tr. Vol. 3, 682:23 – 683:1. He further agreed that it is "almost impossible to analyze a model when you don't have the data or you don't have at least access to the source of it." Tr. Vol. 3, 683:10-16.

115. Witnesses for the Department and EDF testified regarding numerous flaws in Mr. Dunham's analysis that resulted in a significant overestimation of the likely costs of the proposed rule, as well as a nearly complete lack of transparency regarding his model and the data he used as inputs to that model.

116. Brandon Powell testified on behalf of the Department regarding the JDA Analysis. Mr. Powell is the Engineering Bureau Chief of the Oil Conservation Division ("OCD") of the New Mexico Energy, Minerals, and Natural Resources Department. *See* NMED Rebuttal Exhibit 17 (Written Rebuttal Testimony of Brandon Powell).

117. Mr. Powell testified that the JDA Analysis significantly overstated the number of oil and natural gas wells currently in operation across New Mexico, according to the OCD's official database. Mr. Powell also testified regarding potential inconsistencies in the JDA Analysis related to: (i) production volumes from low volume oil and natural gas wells statewide, and (ii) assumptions made about the prevalence of certain types of equipment at all wells. *Id.* at 2.

118. Mr. Dunham's analysis is premised on his estimate that there are 84,247 wells in New Mexico that would be affected by Part 50. Mr. Powell testified that OCD's records show that there are 53,338 active oil and natural gas wells in New Mexico. Id. at 3. OCD data also shows that total well counts for oil and natural gas wells characterized as stripper or marginal are also well below the count reported for "Low Production wells" in the JDA Analysis. *Id.* at 6.

119. NMED's cost estimates are based on an estimated affected well count of 47,937. This number represents the active wells shown in the OCD database within the eight counties to which the rule applies, as specified in Section 20.2.50.2 of the proposed rule. NMED Rebuttal Exhibit 19, p. 3; NMED Exhibit 94 – 2020 Producing Wells Spreadsheet.

120. In its equipment cost estimates, the JDA Analysis assumed that all natural gas wells have flares. Mr. Powell testified that this this is an unreasonable assumption. Flares are not common on natural gas wells in New Mexico because hose wells are specifically designed to capture the natural gas for resale purposes because that is the targeted commodity. Further, many of the newer oil wells across the state use centralized facilities and do not have one flare per well;

rather, one flare may serve numerous wells. *Id.* at 7; Tr. Vol. 3, 742:16 – 743:16.

121. Mr. Powell also testified that it is not the case that each oil well has a flare, as assumed in the JDA Analysis. Tr. Vol. 3, 743:17-24.

122. The JDA Analysis also assumed that all natural gas wells have enclosed combustion devices, thermal oxidizers, and glycol dehydrators. Mr. Powell testified that this is not a reasonable assumption because operators do not install such equipment at each individual well; rather, equipment is installed where needed and tends to be installed at more centralized facilities or locations. NMED Rebuttal Exhibit 17, p. 7; Tr. Vol. 3, 743:25 – 744:5.

123. Mr. Powell testified that Table 7 of the JDA Analysis does not reflect true well applications in New Mexico, and because of that, the cost per well would likely be significantly lower than what is summarized in that Table. Tr. Vol. 3, 744:6-13.

124. Susan Day and Brian Palmer of ERG testified on behalf of the Department regarding the JDA Analysis. *See* NMED Rebuttal Exhibit 19 (Rebuttal Testimony of Susan Day and Brian Palmer).

125. Ms. Day testified that Mr. Dunham's estimated number of affected wells was nearly twice that used as the basis for the cost estimates that ERG compiled, and that this discrepancy results in a significant overestimation of the costs of Part 50 as presented in the JDA Analysis. NMED Rebuttal Exhibit 19, p. 6.0

126. Ms. Day also observed that NMOGA provided nothing by way of underlying data, assumptions, spreadsheets or code to support of Mr. Dunham's modeling and analysis, apart from the base assertions in Mr. Dunham's ten-page memorandum. She noted that, based on her experience with federal rulemakings, modeling the costs and impacts associated with a regulatory action would typically be accompanied by a clear explanation of sources used, why those sources

are the best available, how the data in these sources were extracted (e.g., what filtering may have been applied), a description of all assumptions applied to the data used, justifications for those assumptions, and the step-by-step calculations, with intermediate results, used to create the final estimates of cost and impacts, such that the affected entities and the general public can reproduce those results. Ms. Day testified regarding how the JDA Analysis does not meet many of these expectations for most of the critical components of the analysis. *Id.* at 2-3.

127. Mr. Palmer testified that the JDA Analysis did not correctly attribute costs to the well site or well head. Unlike NMED's cost estimates, which assumed two well heads per wellsite, in Table 7 of the JDA Analysis, Mr. Dunham appeared to apply his costs at the level of the wellhead rather than at the well site. The costs in the "Per Oil Well" and "Per Gas Well" columns appeared to be multiplied by the number of wells from Table 3 of his testimony to obtain the values in the "Production Costs" columns, which were then summed in the "Total Costs" column. Because these costs are all applied at the level of the well head rather than at the wellsite, they appear to significantly overestimate the total cost of the proposed rule. However, because Mr. Dunham provided no supporting documentation of the costs in Table 7, it was not possible to determine how this factor affected the overall cost estimates. *Id.* at 7.

128. By contrast, the Department provided the spreadsheets used to develop the compliance cost estimates for proposed Part 50 beginning in early June of 2021 on the NMED website, and those spreadsheets were filed as exhibits with the Department's direct testimony on July 28, 2021. The spreadsheets present costs at the level of individual emission units and equipment types, with the methodology and references clearly explained, cited, and included in the list of exhibits. This level of detail allows reviewers to evaluate the data sources and assumptions built into the costing exercise and to comment on specific data elements, assumptions,

and methods. Some reviewers, including NMOGA's other witnesses, took advantage of this level of detail provided in the NMED data and cost estimates in preparing their testimony to provide helpful insights that NMED then used to improve the provisions of the proposed rule and cost estimates. *Id.* at 7-8.

129. Regarding the survey of ten unidentified companies from NMOGA's membership that Mr. Dunham relied on to develop his estimates of the equipment and operational costs to comply with proposed Part 50, Mr. Palmer pointed out that neither a copy of the survey instrument (questionnaire) nor the responses and raw data submitted by the companies purportedly surveyed are provided either in the JDA Analysis or in Mr. Dunham's testimony, and thus there is no way to assess their accuracy or variability, how the data were reduced to the values in Table 7, or how they relate to ERG's cost estimates. Regarding NMOGA's claim that all such information was proprietary, Mr. Palmer testified that, even though some data may be considered confidential or proprietary, there are ways for the provider to protect confidential information, for example by aggregating data when there are only a few reporters (e.g., four or less). It is not clear why the survey instrument and some level of raw data, even if aggregated, was not provided to support the cost values set forth in Table 7 of the JDA Analysis. Further, Mr. Dunham did not document how costs were estimated, how the costs per well were calculated, and did not reference data or calculations in any other exhibits. *Id.*at 8-9.

130. The costs presented in Table 7 of the JDA Analysis do not align in any way with ERG's cost estimates, or EPA's estimates used in rulemakings for similar source categories that require the same types of controls. *Id.* at 9-13.

131. Ms. Day evaluated Mr. Dunham's calculation of the net present value of the costs associated with Part 50, presented in Table 8 of the JDA Analysis. Mr. Dunham used a five-year

time frame for this calculation, without providing justification for that approach, which generally assumes a well life of four years. Ms. Day testified that this assumption is likely unrealistic because well life may be considerably longer, and control equipment can often be moved from one location to another as needed. Based on EPA guidance routinely used in federal air quality rulemaking actions, the useful life of the add-on control equipment and equipment modifications required under Part 50 is generally between 10 and 20 years and is commonly assumed to be 15 years. *Id.* at 14.

132. Mr. Dunham further assumed that nearly 85% of the costs of the rule will be incurred by industry in the first year. Ms. Day testified that, given that investments in equipment are typically spread out by affected owners/operators, a more realistic assumption would be that the cost of the regulation can be spread out more evenly over the 15-year useful life timeframe. Under this scenario, the present value of the costs would be significantly lower. *Id.*

133. Ms. Day testified as to serious flaws and lack of information with respect to Mr. Dunham's modeling predicting potential job losses associated with Part 50. She concluded that because Mr. Dunham failed to provide any details regarding his model or the data he used as inputs to that model, it is impossible to evaluate the accuracy of his estimates of job losses in the oil and gas industry or supporting industries. *Id.* at 16.

134. Ms. Day also agreed with additional points made in the testimony of EDF witness Maureen Lackner regarding deficiencies with the JDA Analysis. Specifically, Ms. Lackner noted that Mr. Dunham's assumption that the vast majority of costs will be incurred in the first year did not take into account for compliance phase-in provisions throughout the rule that allow as much as 7 years for operators to comply with control requirements. Ms. Lackner also explained that the JDA Analysis did not consider that industry compliance costs may be offset by revenue received

from captured gas, nor did it consider the avoidance of social costs such as environmental and health effects of oil and gas operations. Finally, Ms. Lackner pointed to supporting research that the proposed rule could lead to job creation in the methane mitigation industry. Tr. Vol. 3, 771:11 – 772:25.

135. No evidence was presented in this proceeding demonstrating that similar regulatory requirements for oil and gas sources adopted by other states and the federal government have resulted in the types of significant negative consequences for industry or the economy, as posited by the JDA Analysis. *See* Tr. Vol. 4, 1027:22 – 1028:10.

136. The Board finds that the number of affected wells determined by NMED from the OCD database is the proper number to use for estimating the costs of Part 50.

137. Considering the above, the Board gave the JDA Analysis its due weight in considering the economic reasonableness of Part 50.

138. The Board finds that the costs entailed by proposed Part 50, as presented in the Department's testimony and exhibits, are reasonable and necessary to further the statutory purpose of attaining and maintaining the ozone NAAQS in the areas of the State specified in Part 50.

139. The Board further finds that Part 50 provides economic relief for low emitting facilities and small, independent operators by way of applicability thresholds throughout the rule, as well as a small business facility definition that allows operators that meet the definition to comply with a more limited set of requirements.

140. The Board finds that the rule also allows operators to spread costs out over time through numerous compliance phase-in provisions which allow as much as seven years to come into compliance with certain control requirements.

H. Data Underlying Part 50

141. The underlying data and information that forms the basis for this rulemaking comes from the NMED Air Quality Bureau's TEMPO database. The Bureau uses this database to record, monitor, and track information about equipment and facilities regulated by the Department under the AQCA and the Board's air quality regulations at Title 20, Chapter 2 of the New Mexico Administrative Code ("NMAC"). This information is collected from different types of submittals, including notice of intent registrations, air quality permit applications, compliance reports, report submittals required by state and federal air quality regulations, settlement requirements, and emissions inventories. NMED Exhibit 32, p. 3.

142. TEMPO maintains information at both the facility level, as well as individual equipment. The type and extent of information will depend on whether the facility is permitted, and which state and/or federal regulations apply. *Id.* at 3-5.

143. To provide underlying data and information for this rulemaking on proposed Part 50, the Department downloaded the following information from TEMPO and provided it to ERG: owner, facility name, AI ID, source type, county, latitude, longitude, source classification, equipment type, category, designation, description, manufacturer, model number, serial number, manufactured date, construction date, operating rating capacity, maximum rating capacity, type of pollutant, quantity of hourly emissions, quantity of annual emissions, primary and secondary control devices, type of fuel, hours of operation, applicable federal air quality regulations, and SCC information. ERG used this data to develop the equipment spreadsheets used to evaluate the emissions reductions and costs of Part 50. The NMED data pulled from TEMPO and provided to ERG is included in a tab in each equipment spreadsheet, and was referred to in the testimony as the "NMED Equipment Data." The ERG spreadsheets generated from the TEMPO data were

provided as exhibits in electronic format as Microsoft Xcel files. *Id.* at 5.

IV. RULE LANGUAGE

In addition to the above-detailed rationale, the Board adopts the provisions of Part 50 as detailed below for the reasons stated:

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

Section 20.2.50.1 is a mandatory section for all rules promulgated by New Mexico state agencies, and it provides the official name of the agency issuing the rule. The Board adopts this proposal because the Board is the issuing agency pursuant to the AQCA.

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. As of the effective date, sources located in the following counties of the state are subject to this Part: Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia.

Section 20.2.50.2 is a mandatory section for all rules promulgated by New Mexico state agencies, and identifies to whom the rule applies: the areas of the State that are subject to, or may become subject to, Part 50. The Board adopts this language because it aligns with the language of the AQCA. In accordance with the AQCA, Part 50 establishes emissions standards for oil and gas production and processing sources located in areas of the State within the Board's jurisdiction that, as of the effective date of the rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard (NAAQS) for ozone, as measured by a design value calculated and based on data from one or more Department monitors. Those areas currently include Chaves, Eddy, Lea, Rio Arriba, San Juan, Sandoval, and Valencia. NMED Exhibit 1, p. 4-5.

The Board rejects the arguments from NMOGA, IPANM, and Kinder Morgan that sources in Chaves and Rio Arriba Counties should not be included in Part 50 on the grounds that the Department has not shown that sources in those counties cause or contribute to ozone concentrations above ninety-five percent of the NAAQS, as measured by Department ozone monitors located within their boundaries, because these arguments run contrary to the language and intent of the statute. Modeling clearly demonstrated that oil and gas sources in the specified counties contributed to ozone levels at the monitors that were registering concentrations exceeding ninety-five percent of the NAAQS. Mr. Baca testified that ozone monitors in the state are located according to EPA regulations under the CAA. These monitor locations are associated with Air Quality Control Regions (AQCR), not counties. The monitor located in Hobbs measures ozone concentrations for the AQCR that encompasses Chaves County, and the monitor located at Navajo Lake measures ozone concentrations for the AQCR that includes the part of Rio Arriba County encompassing the San Juan Basin. Tr. Vol. 1, 297:16 – 309:16.

The Board's statutory directive under the AQCA is not to regulate sources in "counties;" rather it must regulate sources in any "area" of the state where ozone levels exceed ninety-five percent of standard. The Department delineated the scope of Part 50 by county in order to facilitate compliance with the rule because counties have well-established and commonly understood boundaries. Tr. Vol. 1, 305:23 – 306:3. It would be far more difficult for owners and operators of affected sources to determine applicability of the rule if the scope of the rule was based on Air Quality Control Regions. The counties identified in Section 20.2.50.2 contain the majority of oil and gas sources in the major producing basins in the State. If the Board were to exclude sources located in Chaves and Rio Arriba County, it would leave unregulated significant emissions of ozone precursors from oil and gas sources under its jurisdiction, thereby contravening the express intent of the statute, which is to reduce emissions of NOx and VOCs to provide for attainment and maintenance of the NAAQS. Tr. Vol. 1, 309:5-16.

A. If, at any time after the effective date of this Part, sources in any other area(s) of the state not previously specified are determined to be causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated by the U.S. Environmental Protection Agency based on data from one or more department monitors, the department shall petition the Board to amend this Part to incorporate the sources in those areas.

(1) The notice of proposed rulemaking shall be published no less than one-hundred and eighty (180) days before sources in the affected areas will become subject to this Part, and shall include, in addition to the requirements of the Board's rulemaking procedures at 20.1.1.301 NMAC:

(a) a list of the areas that the department proposed to incorporate into this Part, and the date upon which the sources in those areas will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for throughout this Part, for sources within the areas subject to the proposed rulemaking to come into compliance with the provisions of this Part.

(2) In any rulemaking pursuant to this Section, the Board shall be limited to consideration of only those proposed changes necessary to incorporate other areas of the state into this Part.

The Board adopts this section with language proposed by the Department and NMOGA, and supported by Kinder Morgan, that requires a rulemaking to incorporate sources in other areas of the state, specifies that the effective date of such changes will be at least 180 days from the date of publication of the notice of rulemaking, and specifies the type of information that must be included in proposed revisions for a rulemaking to add sources in other areas of the State. NMED Rebuttal Exhibit 1, p. 2. The language in this Subsection limiting the rulemaking required under Section 20.2.50.2 to only those proposed changes and supporting evidence necessary to incorporate other areas of the State is necessary to ensure that the rulemaking does not become a vehicle for anyone to attempt to propose changes to other sections of Part 50, thereby expanding the scope of the rulemaking and bogging down the Department's and the Board's resources. *Id.*

B. Once a source becomes subject to this Part based upon its potential to emit, all requirements of this Part that apply to the source are irrevocably effective unless the source obtains a federally enforceable limit on the potential to emit that is below the applicability

thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.
[20.2.50.2 NMAC – N, XX/XX/2021]

Subsection B of Section 20.2.50.2 specifies that once a source becomes subject to Part 50, the requirements of Part 50 are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in Part 50. The Board adopts this language and rejects IPANM's proposal to delete the word "irrevocably" because it ensures that the emissions reductions achieved by Part 50 will be permanent.

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

Section 20.2.50.3 is a mandatory section for all rules promulgated by New Mexico state agencies and identifies the enabling legislation that authorizes the issuing agency to promulgate the rule. Section 20.2.50.3 lists the statutory authorities pursuant to which the Board is authorized to adopt Part 50. The Board adopts this proposal for the reasons stated in NMED Exhibit 1, pp. 4-5 and NMED Exhibit 32, pp. 12-13.

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

Section 20.2.50.4 is a mandatory section for all rules promulgated by New Mexico state agencies, and provides the length of time the rule is intended to be enforceable. The Department proposed that Part 50 be permanently in effect from the effective date established in Section 20.2.50.5. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 13.

20.2.50.5 EFFECTIVE DATE: Month XX, 2022, except where a later date is specified in another Section. [20.2.50.5 NMAC - N, XX/XX/2021]

Section 20.2.50.5 is a mandatory section for all rules promulgated by New Mexico state agencies, and provides the date the rule goes into effect. This date depends on when the final rule is published in the New Mexico Register. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 13.

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, compression, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

Section 20.2.50.6 is a mandatory section for all rules promulgated by New Mexico state agencies, and provides a statement describing the purpose of the rule and its intended effect. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 13. The Board declines Kinder Morgan's request for further clarification in the SOR regarding the consideration of co-benefits. The AQCA authorizes the EIB to "give weight it deems appropriate" to multiple factors in its rulemaking, including costs to industry, health, welfare, and the public interest. NMSA 1978, § 74-2-5.F.

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.

A. "Auto-igniter" means a device that automatically attempts to relight the pilot flame of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

The definition of "Auto-igniter" was derived in part from Colorado Reg. 7, Section I.B.5. The Department made revisions to its original proposal based on comments from NMOGA. *See* NMED Rebuttal Exhibit 1, p. 4. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 14, and NMED Rebuttal Exhibit 1, p. 4.

B. "Bleed rate" means the rate in standard cubic feet per hour at which gas is continuously vented from a pneumatic controller.

The definition of "Bleed rate" was derived in part from NSPS Subpart OOOOa, 40 C.F.R.

§ 60.5430a. The Department revised its original definition to align with federal and other state interpretations of the term based on comments from NMOGA, as described in NMED Rebuttal Exhibit 1, p. 4. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 14, and NMED Rebuttal Exhibit 1, p. 4.

C. "Calendar year" means a year beginning January 1 and ending December 31.

The definition of "Calendar year" is the commonly accepted interpretation of a calendar year. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 14.

D. "Centrifugal compressor" means a 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 a mechanical rotating vane or impeller. A screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

The definition of "Centrifugal compressor" was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The Board adopts this proposal for the reasons stated in NMED Ex. 32, p. 14.

E. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere during operation.

The definition of "Closed vent system" was derived in part from language in Colorado Reg. 7, Section I.J, and NSPS Subpart OOOOa, 40 C.F.R. § 60.5411a(a). The Department added "during operation" at the end of the definition to clarify the intent of this provision. During maintenance there will be some emissions associated with venting, and the requirement reflects the expectation that during normal operations there will be no loss of VOC to the atmosphere. *See* Tr. Vol. 6, 1888:7 – 1889:3. The Board adopts this proposal for the reasons stated above and in NMED Exhibit 32, p. 14. NMOGA had proposed to strike "no" and replace with "minimal," but it supports the current proposal with "during operation" at the end. *See also* NMOGA SOR 51.

F. "Commencement of operation" means for an oil and natural gas well site, the

date any permanent production equipment is in use and product is consistently flowing to a sales line, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

The definition of “Commencement of operation” describes when operation of a production well may be presumed to have begun, and was derived in part from Colorado Reg. 7, Section I.B.7. The Board rejects NMOGA’s proposal to strike “but no later than the end of well completion operation” for lack of adequate justification in the record, and adopts the Department’s proposal for the reasons stated in NMED Exhibit 32, pp. 14-15 and NMED rebuttal Exhibit 1, p. 5.

G. “Component” means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water, or methanol.

The definition of “Component” was derived in part from Colorado Reg. 7, Section I.B.10. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 14.

H. “Connector” means flanged, screwed, or other joined fittings used to connect pipeline segments, tubing, pipe components (such as elbows, reducers, “T's” or valves) to each other; or a pipeline to a piece of equipment; or an instrument to a pipe, tube, or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

The definition of “Connector” was derived in part from Colorado Reg. 7, Section I.B.11. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 14.

I. “Construction” means fabrication, erection, or installation of a stationary source, including but not limited to temporary installations and portable stationary sources, but does not include relocations or like-kind replacements of existing equipment.

The definition of “Construction” describes the types of activities that constitute construction. This definition was taken from the Board’s regulations for air quality construction permits at 20.2.72 NMAC. The Department agreed with NMOGA’s proposed revision to exclude relocations and like kind replacements of existing sources from the definition, but disagreed with the proposal to exclude replacements, temporary installations and portable stationary sources because the Department intended to include temporary and portable equipment under Part 50.

The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, p. 15; NMED Rebuttal Ex. 1, p. 4; NMOGA SOR 56; and the evidence presented by GCA: the relocation of an existing compressor engine, where the engine is not otherwise rebuilt or reconstructed, should not be considered "construction" of that engine, and should not provide a basis for converting the engine from an existing engine into a new engine that is subject to the proposed rule's more-stringent emissions standards for new engines. GCA Exhibit 12 (Dutton Direct) at 13; GCA Exhibit 9 (Sheldon Direct) at 19. *See also* GCA proposed SOR 1-5 and 32-38.

J. "Control device" means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices may include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part. A VRU or other equipment used primarily as process equipment is not considered a control device.

The definition of "Control device" was derived in part from Colorado Reg. 7, Part A, Section II.A.7. The Board adopts this definition for the reasons presented by the Department and with clarifying changes included from NMOGA. As part of its final proposal, the Department clarified that a VRU or other equipment used primarily as process equipment is not considered a control device to address NMOGA's concerns. The term "Vapor Recovery Unit" or "VRU" is well understood by the regulated industry, and VRUs used to comply with the emission standards of Part 50 are subject to the relevant requirements under this Part. Although VRUs can be used as both a process and a control device, NMED did not intend to regulate VRUs used as process equipment under Part 50; rather, only VRUs that are utilized to meet the emission standards of this Part are subject to the requirements of 20.2.50.115. In each Section that establishes an emission standard, the owner or operator must identify the control device being used to comply with the emission standards; there is already an affirmative record if a VRU is being used as a control device to comply with this Part. No additional definitions or documentation are necessary to make this distinction. Ms. Kuehn confirmed that by including VRUs in the definition of control device, NMED was not trying to adopt a global determination that all VRUs are control devices. *See* Tr. Vol. 6, 1889:6-19. NMED only intended to regulate VRUs that are used to comply with the emission standards of Part 50, and did not intend to exempt VRUs unless they are primarily used as process equipment. *See* NMED Rebuttal Exhibit 1, pp. 5-6; and NMOGA SOR 52.

K. "Department" means the New Mexico environment department.

The Board adopts the Department's proposal because the definition of "Department" is necessary to define which agency is referred to in Part 50.

L. "Design value" means the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

The term "design value" was added by the Department based on a proposal by IPANM. The Board adopts this proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 6, and rejects NMOGA's proposed clarification as unnecessary.

M. "Downtime" means the period of time when equipment is not in operation.

The definition of "downtime" was derived in part from Merriam-Webster dictionary. The Department revised its original proposal based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 16, and NMED Rebuttal Exhibit 1, p. 6, and rejects NMOGA's proposed clarification to use the word "inoperable" as unnecessary.

N. "Drilling" or "drilled" means the process to bore a hole to create a well for oil and natural gas production.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

O. "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 cleanup.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

P. "Enclosed combustion device" means a combustion device where waste gas is combusted in an enclosed chamber solely for the purpose of destruction. This may include, but is not limited to an enclosed flare or combustor.

The definition of "Enclosed combustion device" is based on common usage of the term in oil and gas regulatory provisions. *See, e.g.*, NSPS Subpart OOOOa, 40 CFR § 60.5412(d)(1). The definition was developed during rule drafting based on the knowledge and experience of NMED technical staff, and the Department made revisions to its initial proposal based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 16, and NMED Rebuttal Exhibit 1, p. 7.

Q. "Existing" means constructed or reconstructed before the effective date of this Part.

The definition of "Existing" is required because the applicability of numerous requirements and timeframes in Part 50 is based on whether a source is "existing" or "new." The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 16-17; and NMOGA SOR 55.

R. "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.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

S. “Flowback vessel” means a vessel that contains flowback.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

T. “Gathering and boosting station” means a facility, including all equipment and compressors, located downstream of a well site that collects or moves natural gas prior to the inlet of a natural gas processing plant; or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation. Gathering and boosting stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

The definition of “Gathering and boosting station” was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The Department agreed with revisions to this definition proposed by NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 9, 17, and NMED Rebuttal Exhibit 1, p. 16.

U. “Glycol dehydrator” means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

The definition of “Glycol dehydrator” was derived in part from Colorado Reg. 7, Section I.B.15. The Board adopts this proposal for the reason stated in NMED Exhibit 32, p. 15.

V. “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.

The Department proposed to add a definition of “High-bleed pneumatic controller” based on comments and testimony from NMOGA, IPANM, and GCA. This definition is derived from Colorado Reg. 7, Section III. The definition helps provide clarity by differentiating between controller types. The Board adopts this proposal for the reasons provided in the industry parties’ testimony, NMED Rebuttal Exhibit 1, pp. 8-9, and Ms. Kuehn’s testimony at Tr. Vol. 7, 2024:22 – 2025:5.

W. “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 requires flowback to expel fracture fluids and solids.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

X. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

Y. “Hydrocarbon liquid” means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.

The definition of “Hydrocarbon liquid” was derived in part from Colorado Reg. 7, Section I.B.16. The Department made revisions to its original proposal based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 17; NMED Rebuttal Exhibit 1, p. 8; and NMOGA SOR 57.

Z. “Inactive well site” means a well site where the well is not being used for beneficial purposes, such as production or monitoring, and is not being drilled, completed, repaired or worked over.

The Board adopts this definition as proposed by CEP and Oxy USA in connection with their proposal set out and adopted in Section 116.

AA. “Injection well site” means a well site where the well is used for the injection of air, gas, water or other fluids into an underground stratum.

The Board adopts this definition as proposed by CEP and Oxy USA in connection with their proposal set out and adopted in Section 116.

BB. “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 above de minimis amounts to the atmosphere as part of the actuation cycle.

The Department proposed to add a definition of “Intermittent pneumatic controller” based on comments and testimony from NMOGA, IPANM, and GCA. This definition is derived from Colorado Reg. 7, Section III. The definition helps provide clarity by differentiating between controller types. The Board adopts this proposal for the reasons provided in the industry parties’ testimony, NMED Rebuttal Exhibit 1, pp. 8-9, and Ms. Kuehn’s testimony at Tr. Vol. 7, 2024:22 – 2025:5.

CC. “Liquid unloading” means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

The definition of “Liquid unloading” was derived from general information on EPA’s Natural Gas STAR website and the EPA publication “Options for Removing Accumulated Fluid and Improving Flow in Gas Wells” (NMED Exhibit 44). The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 17.

DD. “Liquid transfer” means the unloading of a hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport.

The definition of “Liquid transfer” was derived from general information from EPA’s website and EPA’s AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, Section 5.2.2 (NMED Exhibit 43). The Department made revisions to its initial proposal based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 17, and NMED Rebuttal Exhibit 1, p. 8.

EE. “Local distribution company custody transfer station” means a metering station where the local distribution company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the local distribution company's intrastate transmission or distribution lines.

The definition of “Local distribution company custody transfer station” was derived from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 17-18.

FF. “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.

The Department proposed a definition of “Low-bleed pneumatic controller” based on comments and testimony from NMOGA, IPANM, and GCA. This definition is derived from Colorado Reg. 7, Section III. The definition helps provide clarity by differentiating between controller types. The Board adopts this proposal for the reasons provided in the industry parties’ testimony, NMED Rebuttal Exhibit 1, pp. 8-9, and Ms. Kuehn’s testimony at Tr. Vol. 7, 2024:22 – 2025:5.

GG. “Natural gas-fired heater” means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

The definition of “Natural gas-fired heater” was derived in part from Colorado Reg. 7, Part E, section II.A.3.p. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 18.

HH. “Natural gas processing plant” means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, 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.

The definition of “Natural gas processing plant” was derived from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 18.

II. “New” means constructed or reconstructed on or after the effective date of this Part.

The definition of "New" is required because the applicability of numerous requirements and timeframes in Part 50 are based on whether a source is "existing" or "new". The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 18.

JJ. "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 instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.

The Department proposed a definition of "Non-emitting controller" based on comments from NMOGA. This definition establishes the meaning of the term and the Department's intended use of the term in Part 50. The Board adopts this proposal for the reasons stated in NMOGA's testimony and NMED Rebuttal Exhibit 1, pp. 8-9.

KK. "Occupied area" means the following:
(1) a building or structure used as a place of residence by a person, family, or families, and includes manufactured, mobile, and modular homes, except to the extent that 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 similar place of outdoor public assembly.

The Department proposed this definition as part of its support for the joint proposal of CEP and Oxy USA at Subparagraph (3) of Paragraph (3) of Subsection C of Section 20.2.50.116. The Board adopts this definition for the reasons given by CEP and OXY USA in connection with the Proximity Proposal adopted as part of Section 116. The Board rejects NMOGA's proposed revisions as not clarifying; national forests and similar areas of dispersed recreation will not reasonably be construed as "occupied areas."

LL. "Operator" means the person or persons responsible for the overall operation of a stationary source.

The definition of "Operator" was derived in part from the Clean Air Act at 42 U.S.C Section 7411. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 19.

MM. "Optical gas imaging (OGI)" means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

The definition of "Optical gas imaging (OGI)" was derived in part from Colorado Reg. 7, Section I.B.17, and NSPS Subpart OOOOa, 40 C.F.R. § 60.5397a. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 19.

NN. "Owner" means the person or persons who own a stationary source or part of a stationary source.

The definition of "Owner" was derived in part from the Clean Air Act at 42 U.S.C Section 7411. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 19.[1]

OO. "Permanent pit or pond" means a pit or pond used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

The definition of "Permanent pit or pond" was derived in part from the New Mexico Oil Conservation Commission's regulations at 19.15.17 NMAC. The Department revised its initial proposal based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 19, and NMED Rebuttal Exhibit 1, p. 8.

PP. "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) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

The definition of "Pneumatic controller" was derived in part from Colorado Reg. 7, Section

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[1] IPANM's proposed definition of "ozone precursor," which would have followed the definition for "Owner," as a non-substantive clarification is rejected as unnecessary; the Department has already described ozone precursors.

III.B.10. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 19, and NMED Rebuttal Exhibit 1, pp. 8-9.

QQ. "Pneumatic diaphragm pump" means a positive displacement pump powered by pressurized 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.

The definition of "Pneumatic diaphragm pump" was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The Department revised its definition based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 19-20, and NMED Rebuttal Exhibit 1, p. 9.[2]

RR. "Potential to emit (PTE)" means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions 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.

The definition of "Potential to emit (PTE)" was derived from the Board's air quality operating permit regulations at 20.2.70 NMAC. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 20, and NMED Rebuttal Exhibit 1, p. 18.

WEG's proposed changes to the definition of PTE would include emissions from "non-mobile source" at a well site prior to commencement of operations, and are rejected because they might cause confusion as to the scope of NMED's jurisdiction: NMED does not issue "drilling" permits for wellhead sites; that is the jurisdiction of the New Mexico Oil Conservation Division.

[2] IPANM's proposal to include a definition of "portable stationary source," which would have followed the definition of "Pneumatic diaphragm pump," as a clarification is rejected; the definition of "stationary source" already includes such definition.

Activities and emissions (waste) associated with the drilling of wells are also within the jurisdiction of the OCD. After the well is drilled, NMED is responsible for regulating the equipment located at the well site associated with the production of oil and gas. Further, the term "non-mobile" is not defined in the Clean Air Act, and it is unclear what equipment would be included. The Department has no way of determining what emissions may occur from such equipment or if such emissions are ozone precursors. NMED Rebuttal Exhibit 22 (Rebuttal Testimony of M. Baca), p. 2. *See also* NMOGA SOR 59.

SS. "Pre-production operations" means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil or natural gas well.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

TT. "Produced water" means a liquid that is an incidental byproduct from well completion and the production of oil and gas.

The definition of "Produced water" was derived from the New Mexico Oil Conservation Commission's regulations at 19.15.2 NMAC. The Department proposed revisions to this definition based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 20; NMED Rebuttal Exhibit 1, p. 10; NMOGA SOR 60, and footnote 38 in its redline.

UU. "Produced water management unit" means a recycling facility or a permanent pit or pond that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), either of which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

The definition of "Produced water management unit" was derived in part from the New Mexico Oil Conservation Commission's regulations at 19.15.2, 19.15.17, and 19.15.34 NMAC. The Department proposed revisions to this definition based on comments from NMOGA. The

Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 20, and NMED Rebuttal Exhibit 1, p. 10.

The Board rejects NMOGA's proposal to delete "recycling facility" from this definition because the Department intended to include recycling facilities within the meaning of this term as used in Part 50. *See also* the supporting information in Section 126.

VV. "Qualified Professional Engineer" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

The definition of "Qualified professional engineer" was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 20-21.

WW. "Reciprocating compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

The definition of "Reciprocating compressor" was derived from Colorado Reg. 7, Section I.B.24. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 21.

XX. "Reconstruction" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

The definition of "Reconstruction" was derived from the Board's air quality construction permit regulations at 20.2.72 NMAC. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 21.

YY. "Recycling facility" means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

The definition of "Recycling facility" was derived in part from the New Mexico Oil

Conservation Commission's regulations at 19.15.34 NMAC. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 21, and NMED Rebuttal Exhibit 1, p. 10. The Board rejects NMOGA's proposal to delete this definition from Part 50 because NMED intended to include recycling facilities within the definition of Produced Water Management Unit, and this definition is necessary to make clear the intended meaning of a recycling facility as used in Part 50. *See also* the definition of "produced water management unit" above, and the discussion in Section 126 below.

ZZ. "Responsible official" means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

The definition of "Responsible official" was derived from the Board's operating permit regulations at 20.2.70 NMAC. The Department revised its original proposal based on comments from NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 21; NMED Rebuttal Exhibit 1, p. 10-11; and NMOGA SOR 61.

AAA. "Routed pneumatic controller" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.

The Department proposed a definition of "Routed pneumatic controller" based on comments from NMOGA. The term is used in Section 122. This definition establishes the meaning of the term and the Department's intended use of the term in Part 50. The Board adopts this proposal for the reasons stated in the NMOGA's testimony and NMED Rebuttal Exhibit 1, pp. 8-9.

BBB. "Small business facility" means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of

another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited-service workers.

The definition of "Small business facility" is intended to provide regulatory relief to small, independent operators by requiring compliance with only a limited subset of requirements in Part 50. The definition distinguishes those companies that are independently owned, have low annual revenues (less than $250,000), and a small number of employees (10 or fewer), from those companies with larger annual revenues ($250,000 or greater) and a greater number of employees (more than 10 employees). NMED Exhibit 102, p. 14.

The Board adopts this definition for the reasons set out by NMED and CEP. Three principal criteria delineate between small, independent businesses and large, vertically integrated companies. The first criterion is ownership structure, which distinguishes companies that are independently owned and operated and are not a subsidiary or division of another company from larger corporations. The differences between small and large companies include the size of the business, number of employees, revenue, legal structures, and financing and tax requirements. Differences in how these companies operate, their ability to access and finance capital, and their overall size affect their operations. *See* NMED Exhibit 102 (Direct Testimony of Susan Day and Elizabeth Bisbey-Kuehn), p. 13.

The second criterion is the total number of staff employed by the company, which is an indication of the company's personnel and staff resource capacity to interpret and implement the requirements of the rule. Larger companies have the financing capacity to employ dedicated environmental, health, and safety specialists; these staff typically monitor the company's compliance with numerous state and federal environmental regulations. Small companies employing fewer numbers of employees typically do not have the staffing or funding capacity to finance dedicated environmental compliance specialists. *Id.*at 14.

The third criterion is annual revenue. The cost of complying with the requirements of Part 50 may disproportionately impact the smallest companies and may result in early abandonment of small business-owned wells, which, in turn, may result in increased uncontrolled air emissions from abandoned wells. By establishing a definition for small business facility, the provision tailors the rule to require robust equipment and emission monitoring for smaller, independent operations, while simultaneously balancing those requirements against the unintended negative environmental consequences resulting from early abandonment. *Id.*

To aid in the development of the small business facility provisions, the Department contracted ERG to prepare a report analyzing business structure, revenues, and employment characteristics of the oil and gas companies operating in New Mexico. NMED provided ERG with the names and addresses for well owners/operators and other affected facilities compiled from the NMED Equipment Data and NM Oil Conservation Division data. Using this data, ERG created a master list of 535 well owners/operators and owners/operators of other affected facilities by combining the two lists and eliminating duplicate entries. *See* NMED Exhibit 102, p. 3; NMED Exhibit. 104 – Owner Address List Final Spreadsheet. ERG used information on industry classification signified by North American Industry Classification System (NAICS) code, as well as the names and addresses of the companies on the master list, to identify and link facilities to global ultimate parent companies in the Dun and Bradstreet (D&B) business database. Information on revenues and employment for global ultimate parent companies was also obtained from D&B. *See* NMED Exhibit 102, p. 3. This analysis identified which companies operating in New Mexico were independent, in the sense that they did not have a separate global ultimate parent company.

See id. at 3-6. ERG then used oil and gas well production data for New Mexico owner/operators from the Go-Tech website to calculate an estimate of the revenue per well and the average value of the oil and gas production per well for each owner/operator. *See* NMED Exhibit 102, pp. 8-9.

The Department used the data compiled by ERG to establish the thresholds for small business facilities in Part 50. These thresholds were chosen because the data compiled by ERG indicated that those thresholds balanced the costs of compliance with Part 50 against a company's ability to finance the costs of compliance, and would not put the majority of companies at risk of becoming insolvent and therefore cause wells to be abandoned without remediation. *Id.* at 11.

The Department estimated the annual average cost of compliance for a representative well site facility to determine the number of companies that could finance those compliance costs. The representative facility was assumed to have facility-wide emissions greater than 5 TPY VOC, requiring quarterly LDAR monitoring under Section 20.2.50.116; a storage vessel emitting greater than 2 TPY, requiring a control device, and an annual inspection of the storage vessel under Section 20.2.50.123. The annual average cost of compliance for the representative facility was estimated at $37,945 (based on an average cost of $32,400 to control a storage vessel, $4,385 for quarterly LDAR monitoring, and $1,160 for an annual inspection). Because the cost estimates are based on the average cost of compliance for companies operating throughout the sector, the cost estimates are conservative and may overestimate the true cost of compliance for an individual facility. NMED then ranked the companies by GULT revenue from highest to lowest revenue and screened the companies that reported $1,000,000 or less and $250,000 or less to determine how many of those companies had per well site revenue less than the cost of compliance for the representative facility. Based on this review, NMED determined that 96 companies reporting a Global Ultimate (GULT) Parent revenue of $1,000,000 and less had a calculated revenue per well less than $37,945.

These companies operate approximately 9,277 wells or 18% of the total wells (9,277/50,866). NMED determined that 54 companies reporting a GULT revenue of $250,000 and less had a calculated revenue per well less than $37,945. These companies operate approximately 4,638 wells or 9% of the total wells (4,638/50,866). *Id.* at 11-12.

The Department then determined the average annual cost of compliance for a facility meeting the small business definition at $4,385 (based on a conservative quarterly LDAR monitoring requirement). According to the report, few companies have a revenue of less than $4,385 per well. *Id.* at 12.

Based on the above, the Department established $250,000 as the revenue threshold to meet the small business definition, based on the need to require robust emission reduction requirements for a majority of wells and facilities; to tailor the requirements for companies with low annual revenue; and to reduce the potential early abandonment of wells that will result in increased uncontrolled air emissions and significant public cost to remediate those wells. *Id.*

Based on the ERG report and the proposed definition, a total of 82 companies that operate 4,638 wells would qualify as small business facilities under the thresholds established in the rule. Therefore, under this definition, 15% of the total number of companies (82/535) subject to Part 50 would be considered owners/operators of small business facilities, and 9% of the total number of wells (4,638/50,866) would be considered small business facilities. NMED also estimated the revenue from a well producing 7.5 bbl of oil per day, (7.5 bbl oil/day * 365 days/year * $60.00/bbl of crude oil) as $164,250 per year (or $450 per day). Comparing this estimated revenue with the estimated cost of complying with the small business provisions of Part 50 (estimated at $4,385), it would cost companies approximately 2.6% of total revenue to comply. The estimated cost of compliance for the representative facility (estimated at $37,945) as a percentage of the total estimated revenue is approximately 23% of total revenue. *Id.*

Although gross annual revenues are not a measure of a company's profitability, sales and revenues are commonly used metrics to evaluate the impact that regulatory burdens may place on small, affected entities. In particular, EPA guidance states that "[i]mpacts on small businesses are generally assessed by estimating the direct compliance costs and comparing them to sales or revenues." NMED Rebuttal Exhibit 10 (EPA Guidelines for Preparing Economic Analyses [March 2016]), pp. 9-14. Moreover, the small business definition in proposed Part 50 is two-pronged, containing an employment component in addition to a revenue component. NMED and other state and federal agencies routinely use multi-pronged approaches (e.g., revenues and employment) to set small business definitions.

The Board rejects the argument by IPANM and NMOGA that the definition should use a 50-employee threshold based on the definition of "small business" in the New Mexico Small Business Regulatory Relief Act. Similar to exempting low-producing wells, a 50-employee threshold would exempt at least 85% of the companies operating in New Mexico, and approximately 40% of the wells analyzed. *See* Tr. Vol. 3, 945:23 – 946:18.

The Board weighed the argument by IPANM and NMOGA that using a revenue threshold could result in operators moving in and out of qualifying as a small business from one year to the next due to uncertainties in commodity prices, but rejects it as a basis for removing the threshold altogether. In this rulemaking, it is appropriate to take a snapshot of the industry to profile the affected universe of companies. There will always be economic fluctuations, and both commodity prices and production can be variable. In federal rulemakings similar to Part 50, it is standard practice to pick a snapshot of conditions in the regulated industry when estimating compliance costs and small business impacts. *See* Tr. Vol. 3, 946:19 – 947:6.

The Board rejects NMOGA and IPANM's argument that the Board should adopt an approach that would entirely exempt low producing wells from Part 50 because it leaves too many emissions sources unregulated, and runs contrary to the intent of the Board's statutory duties specified in the AQCA. *See* Tr. Vol. 4, 1024:24 – 1027:12. Just because a well is low producing does not mean it is low emitting; based on the number and age of low-producing wells in New Mexico, leaving them out of the rule would amount to leaving tens, if not hundreds, of thousands of tons of ozone precursor emissions uncontrolled and unregulated. *See id.* The Department's proposal already provides relief to low-emitting facilities by establishing PTE thresholds throughout the rule. Facilities that emit below these thresholds are not subject to the requirements for the particular equipment or process to which the rule section at issue applies. *See* Tr. Vol. 3, 945:15-23.

Ms. Hull conducted a review of emissions from stripper wells in New Mexico, and determined that "stripper wells are responsible for a disproportionately large portion of emissions, over 22% compared to their low share of production . . . ." 8 Tr. 2612:20-25. This information underscores "the need for frequent instrument-based inspections at these well sites to identify abnormal operating conditions that result in excess venting or leaking." 8 Tr. 2613:1-4. Ms. Hull also conducted a review to determine ownership of stripper wells in New Mexico. This review demonstrates that "companies who operate stripper wells also operate many higher-producing wells." 8 Tr. 2612:12-14. Specifically, companies that own stripper wells are responsible for 99.6% of oil production and 97% of gas production in the state. 8 Tr. 2611:25-2612:3.

An asset portfolio consisting solely of stripper wells can still produce significant amounts of oil and gas and generate considerable income. Testimony of Tom Alexander, 10 Tr. 3237:12-25. Companies that operate multiple stripper wells located close together will often view the combined assets as one entity when evaluating potential compliance costs and mitigation efforts. 10 Tr. 3238:9-14. Companies that operate low-producing stripper wells also operate high producing assets. *See* CEP SOR 358-373.

In the course of this rulemaking, no party took issue with the data included in NMED Exhibit 105, as compiled by ERG, and no party submitted proposed changes to the small business facility definition pursuant to the Board's rulemaking procedures at 20.1.1.302.A(5) NMAC (requiring a notice of intent to present technical testimony to "include the text of any recommended modifications to the proposed regulatory change."). *See* Tr. Vol. 3, 885:2-14; NMOGA App. B at 7; NMOGA Ex. 47 at 7; 4 Tr. 991:18-19, -996:14-997:15; and IPANM Ex. 1 [Proposed Modifications]; IPANM Notice of Intent to Present Rebuttal Technical Testimony; 3 Tr. 931:13-22, and IPANM Ex. 2 at 20, 3 Tr. 930:10-20, -932:3-24. The Board rejects IPANM's proposed changes, supported by NMOGA, as unsupported by substantial evidence in the record.

NMED's proposed definition of "Small business facility," together with the provisions of Section 20.2.50.125, sets reasonable minimum requirements such as best management and operational practices, calculation of potential to emit, and repairing leaks, which all companies regardless of size or structure should be able to comply with if they want to operate in this State. *See* Tr. Vol. 3, 1027:7-13.

CCC. "Stabilized" means, when used to refer to stored condensate, that the condensate has 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."

The Department proposed a definition of "Stabilized" based on its agreement at the hearing with language proposed by NMOGA. Tr. Vol. 4, 1230:1-5. The Board adopts this proposal for the reasons stated in NMOGA's testimony.

DDD. "Standalone tank battery" means a tank battery that is not designated as associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station.

The Department proposed a definition of "Standalone tank battery" based on testimony from NMOGA to delineate between those tank batteries that are associated with other defined facilities and those that are not. This definition provides clarity regarding the applicability of the requirements in Part 50 to storage tanks not associated with another facility regulated under Part 50. The Board adopts this proposal for the reasons stated at Tr. Vol 4, 1110:2-7; 1113:9 – 1120:6; and NMOGA SOR 62.

EEE. "Startup" means the setting into operation of air pollution control equipment or process equipment.

The definition of "Startup" was derived from the Board's excess emissions regulations at 20.2.7 NMAC. The Board adopts this definition for the reasons stated in NMED Exhibit 32, p. 22.

FFF. "Stationary source" or "source" means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

The definition of "Stationary source" or "source" was derived from the Board's air quality construction permit regulations at 20.2.72 NMAC. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 22.

GGG. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide

structural support. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck or railcar; a process vessel such as a surge control vessel, bottom receiver, or knockout vessel; a pressure vessel designed to operate in excess of 204.9 kilopascals (29.72 psi) without emissions to the atmosphere; or a floating roof tank complying with 40 CFR Part 60, Subpart Kb.

The definition of "Storage vessel" was derived in part from Colorado Reg. 7, Section I.B.27, and NSPS Subpart OOOOa, 40 C.F.R. § 60.5365a. The Department revised its original proposal based on comments from NMOGA. The Department proposed further revisions to address storage vessels with a floating roof tank complying with federal NSPS regulations based on testimony from NMOGA at the hearing. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 22-23; NMED Rebuttal Exhibit 1, p. 11; Tr. Vol 9, 2881:2 – 2883:5, 2885:4 – 2887:18; and NMOGA SOR 65.

HHH. "Tank battery" means a storage vessel or group of storage vessels that receive or store crude oil, condensate, or produced water from a well or wells for storage. The owner or operator shall designate whether a tank battery is a standalone tank battery or is associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station. The owner or operator shall maintain records of this designation and make them available to the department upon request. A tank battery associated with a well site, gathering or boosting station, natural gas processing plant, or transmission compressor station is subject to the requirements in this Part for those facilities, as applicable. Tank battery does not include storage vessels at saltwater disposal facilities or produced water management units.

The Department proposed a definition of "Tank battery" based on testimony from NMOGA to provide clarity regarding the applicability of the requirements in Part 50 to storage tanks associated with different types of facilities, and further clarify that the term does not apply to storage vessels at saltwater disposal facilities or produced water management units. CDG supports it. The Board adopts this proposal for the reasons stated at Tr. Vol 4, 1110:2-7; 1113:9 – 1120:6; and NMOGA SOR 63-64.

III. "Temporarily abandoned well site" means an inactive well site where the well's completion interval has been isolated. The completion interval is the reservoir interval that is open to the borehole and is isolated when tubing and artificial equipment has been removed and a bottom plug has been set.

The Board adopts this definition as proposed by the Department in connection with the joint proposal of CEP and Oxy USA set out and adopted in Section 20.2.50.116.

JJJ. "Transmission compressor station" means a facility, including all equipment and compressors, that moves pipeline quality natural gas at increased pressure from a well site or natural gas processing plant through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, underground storage, or to other industrial end users. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

This definition clarifies the segment of the oil and gas industry included in this term, as used in the definition of "Gathering and boosting station." Kinder Morgan supports the definition because operations in the transmission segment differ significantly from other segments of industry. This separate definition is necessary to apply each rule section, as appropriate, to the unique transmission segment operations. The Board adopts this proposal for the reasons stated by Kinder Morgan and in NMED Exhibit 32, pp. 8, 22.

KKK. "Vessel measurement system" means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

The Board adopts this definition of "Vessel measurement system" as part of the automatic tank gauging proposal by CEP and Oxy USA set out and adopted in Section 123.

LLL. "Wellhead only facility" means a well site that does not contain any production or processing equipment other than artificial lift natural gas driven pneumatic controllers and emergency shutdown device natural gas driven pneumatic controllers.

The Board adopts this definition as proposed by CEP and OXY USA in connection with their joint completions/recompletions proposal set out and adopted in Section 127.

MMM. "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

The definition of "Well workover" was derived from the MAP Technical Report at NMED Exhibit 10. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 150-52.

NNN. "Well site" means the equipment under the operator's control directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant or gathering and boosting station, if any. A well site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. A well site does not include an injection well site.
[20.2.50.7 NMAC - N, XX/XX/2021]

The definition of "Well site" was derived from Colorado Reg. 7, Section I.B.30, and NSPS Subpart OOOOa, 40 CFR § 60.5430a. The Department revised its original definition to replace the term "Wellhead" with "Well" based on comments submitted by NMOGA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 23, and NMED Rebuttal Exhibit 1, pp. 7, 20-21.

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.
[20.2.50.8 NMAC - N, XX/XX/2021]

Section 20.2.50.8 ensures that if any provision of Part 50 is found by a court to be invalid, such finding will not affect the validity and enforceability of the other provisions of the rule. The Board adopts this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose. [20.2.50.9 NMAC - N, XX/XX/2021]

Section 20.2.50.9 directs that Part 50 must be liberally construed to carry out its purpose. The Board adopts this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions. [20.2.50.10 NMAC - N, XX/XX/2021]

Section 20.2.50.10 provides that repeal or supersession of prior versions of Part 50 will not affect any administrative or judicial action initiated under those prior versions. The Board adopts this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls. [20.2.50.11 NMAC - N, XX/XX/2021]

Section 20.2.50.11 makes clear that compliance with Part 50 does not relieve a person from the responsibility to comply with other laws or regulations. The Board adopts this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2021]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

Section 20.2.50.12 identifies where documents incorporated and cited in Part 50 may be reviewed. The Board adopts this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.23.13-20.2.23.110 [RESERVED]

20.2.50.111 APPLICABILITY:

A. This Part applies to certain crude oil and natural gas production and processing equipment associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

Subsection A outlines the specific sources of air pollutants that are covered under Part 50. The rule applies to certain crude oil and natural gas production and processing equipment associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, handle hydrocarbon liquids or produced water in areas of the state specified in Section 20.2.50.2 and located at well sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations up to the point of the local distribution company custody transfer station. Part 50 applies to state, federal, and privately owned land, but not to tribal lands or Bernalillo County. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 23.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer or an inhouse engineer with expertise in the operation of oil and gas equipment, vapor control systems, and pressurized liquid samples. The emission standards and requirements of this Part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this Part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request. This certified calculation shall be completed before startup for new sources, and within two years of the effective date of this Part for existing sources.

Subsection B specifies how to determine whether a source is subject to Part 50. Owners and operators must calculate the PTE of each potentially affected source to determine if it is subject to requirements under the rule. The PTE calculation must be certified by a qualified profession engineer or inhouse engineer with expertise in the specified areas. This certification is critical to ensuring the potential air emissions from equipment and processes are properly calculated and representative of the source, and present a true and accurate representation of the source's potential emissions. Without this certification, emission calculations may be performed based on process, emission, or operational inputs that are not accurate or representative, which then underestimate the true potential emissions and result in a determination that equipment is not subject to this part. The PTE calculation is the foundation of determining applicability of Part 50 and the certification of the PTE calculation ensures the integrity of how that fundamental calculation is performed. It is imperative that PTE calculations be certified by engineers with relevant background and experience; NMED did agree with NMOGA's proposal to allow in-house engineers to do PTE certifications. The New Mexico licensing statute does not require an engineer employed with a company to be licensed. *See* Tr. Vol. 4, 1169:23 – 1170:4.

NMED added language in the second sentence to clarify that the emission standards and requirements of Part 50 may not be used to reduce the emission rate of a source in order to determine applicability of the rule to that source. *See* Tr. Vol. 4, 1158:7-13. NMED also proposed a compliance date for when PTE certifications must be completed, in recognition of the large number of sources that will need to undergo evaluation and certification under this provision. The Board adopts this proposal for these reasons, as stated above and in NMED Exhibit 32, p. 24.

Several industry parties proposed that consultants who are not engineers should also be able to certify PTE calculations. The Board rejects these proposals. The entire purpose of this subsection is to require certification by an engineer with relevant expertise. Ms. Kuehn explained that in her experience, PTE calculations frequently miscalculate or misrepresent a source's PTE. This often results in compliance issues for the company, which requires enforcement action and consequent revisions to applications and new permits with corrected emissions values. Because of this experience, the Department intended for the PTE calculation to undergo the review of an engineer with that specific type of experience, and for that person to affirmatively sign off that the emissions determination is accurate and representative of the source's true potential to emit. Tr. Vol. 4, 1166:19 – 1168:1.

To the extent the proposal is more stringent than federal law in requiring a qualified professional engineer, the Board finds that based on substantial evidence the proposed rule is more protective of public health and the environment.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

Subsection C specifies that owners and operators of small business facilities as defined in 20.2.50.7 are subject to the requirements of Section 20.2.50.125. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 24; NMED Ex. 102; and NMED Rebuttal Exhibit 1, pp. 11, 98-99.

D. Oil transmission pipelines, oil refineries, natural gas transmission pipelines (except transmission compressor stations), and saltwater disposal facilities are not subject to this Part.
[20.2.50.111 NMAC - N, XX/XX/2021]

Subsection D lists several types of oil and gas-related facilities that are not subject to Part 50. The Department proposed clarifying revisions as suggested by NMOGA to effectuate the Department's intent that the purpose of the rule is not to regulate oil transmission pipelines. *See* Tr. Vol. 4, 1156:5-16; 1157:5-9.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 7-9, 23-24, and Tr. Vol. 4, 1156:5-16, 1157:5-9, and the additional support provided by CDG for the exclusion of salt water disposal facilities: The emissions profile at disposal wells is entirely different than the producing operations that create the incoming water. The disposal wells do not have the same emission sources as production facilities and do not receive produced natural gas or oil. The water received from the producing wells is low volatility, post-flash, and has gone through separation, processing, and treatment at the producing sites. Therefore, the water is at atmospheric conditions. Once the produced water has been separated from hydrocarbons at the producing operations, it is then transported by truck or pipeline to Salt Water Disposal (SWD) facilities for further hydrocarbon removal. Typically, incoming water is comprised of about 0.5 percent hydrocarbons. SWDs remove remaining hydrocarbons and then inject the water into an injection well regulated by EPA's underground injection control program, which is administered by EMNRD's Oil Conservation Division. The disposal well itself is not an emission point because it is injecting water that has been cleaned and filtered and therefore, contains only trace amounts of hydrocarbons.

The oil that is separated from the water at SWD facilities is also different than the oil produced from and E&P sites. It is less volatile and is considered "dead" oil because it has limited flashing and emission potential. Any recovered oil is transported offsite typically to refineries ultimately for beneficial use. Therefore, it is appropriate to exclude SWD from the Proposed Rule. CDG NOI Direct Testimony: Lori Marquez, pgs. 5-6; Il Kim, pgs. 3-4; Jill Cooper, pgs. 4-6; Ashley Campsie, pgs. 5-6; Exhibit CDG 4 - Streams with High Moisture Content; Exhibit CDG 5 - Cost Estimate of the Economic Impacts; Hearing Transcript, Volume 9, 2935:20 – 2936:16; 3033:12 – 3034:6.

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, or good engineering and maintenance practices. When used in this Part, the term manufacturer specifications means either the original equipment manufacturer (or successor) emissions-related design specifications, maintenance practices and schedules, or an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience. The owner or operator shall keep manufacturer specifications on file when available, as well as any alternative specifications that are being followed, and make them available upon request by the department. The terms of 20.2.50.112.A(1) apply any time reference to manufacturer specifications occurs in this Part.

Subsection A of Section 20.2.50.112 outlines general provisions that establish a universal set of requirements applicable to all owners and operators of sources of emissions subject to emissions standards and other requirements of Part 50.

Paragraph (1) of Subsection A of Section 20.2.50.112 establishes work practice standards requiring equipment to be operated and maintained consistent with manufacturer specifications and explains what is meant by the term "manufacturer specifications" as used in Part 50. Based on a proposal by NMOGA, proposed revisions allow owners or operators to use either manufacturer specifications or an alternative set of specifications and maintenance practices and schedules developed by qualified personnel based on engineering principles and field experience. Manufacturer specifications or alternative specifications must be kept on file and provided to the department upon request. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 25 and NMED Rebuttal Exhibit 1, p. 21.

(2) Sources, including associated air pollution control equipment and monitoring equipment, subject to emission standards or requirements under this Part shall at all times, including periods of startup, shutdown, and malfunction, be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions of VOC and NOx. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent consistent with safety and good air pollution control practices. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions beyond levels required by the applicable standard under this Part. The terms of 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.

Paragraph (2) of Subsection A of Section 20.2.50.112 establishes a requirement that equipment be operated a manner that minimizes emissions of air contaminants, including NOx and VOC. This is a standard operational requirement intended to ensure that equipment is used for its intended purpose only; that equipment is maintained in good working order such that it operates within its normal operating parameters, loads, and process and throughput rates; and that owners and operators proactively address any operational issues to avoid excess emissions due to equipment failures, malfunctions, or lack of proper maintenance and operation. This provision includes revisions proposed by NMOGA that clarify the sources covered; specify that the requirement applies at all times including during periods of startup, shutdown, and malfunctions; and clarify the Department's intent that the general duty to minimize emissions does not require the owner or operator to make further efforts to reduce emissions if emission levels required by applicable standards have been achieved. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 25; and NMED Rebuttal Exhibit 1, pp 21-22.

(3) Within two years of the effective date of this Part, owners and operators of a source requiring equipment monitoring, testing, or inspection shall develop and implement a data system(s) capable of storing information for each source in a manner consistent with this Section. The owner or operator shall maintain information regarding each source requiring equipment monitoring, testing, or inspection in a data system(s), including the following information in addition to the required information specified in an applicable section of this Part:

(a) unique identification number;

(b) location (latitude and longitude) of the source;

(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);

(d) for each source, the controlled VOC (and NO_x, if applicable) emissions in lbs./hr. and tpy;

(e) make, model, and serial number; and

(f) a link to the manufacturer maintenance schedule or repair recommendations, or company-specific operational and maintenance practices.

(4) The data system(s) shall be maintained by the owner or operator of the facility.

(5) The owner or operator shall manage the source's record of data in the data system(s). The owner or operator shall generate a Compliance Database Report (CDR) from the information in the data system. The CDR is an electronic report maintained by the owner or operator and that can be submitted to the department upon request.

(6) The CDR is a report distinct from the owner or operator's data system(s). The department does not require access to the owner or operator's data system(s), only the CDR.

(7) The owner or operator's authorized representative must be able to access and input data in the data system(s) record for that source. That access is not required to be at any time from any location.

(8) The owner or operator shall contemporaneously track each monitoring event, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be uploaded into the data system as soon as practicable, but no later than three business days of each compliance event, and when the final reports are received;

(b) certain sections of this Part require a date and time stamp, including a GPS display of the location, for certain monitoring events. No later than one year from the effective date of this Part, the department shall finalize a list of approved technologies to comply with date and time stamp requirements, and shall post the approved list on its website. Owners and operators shall comply with this requirement using an approved technology no later than two years from the effective date of this Part. Prior to such time, owners and operators may comply with this requirement by making a written or electronic record of the date and time of any affected monitoring event; and

(c) data required by this Part shall be maintained in the data system(s) for at least five years.

(9) The department for good cause may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. Such requests may be made no more than once per year. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department. The owner or operator may request a hearing on whether good cause was demonstrated or whether the recommendations approved by the department must be implemented.

Paragraphs (3) through (8) of Subsection A of Section 20.2.50.112 establish requirements for owners and operators to develop and maintain a data system capable of storing monitoring, testing, and inspection information as required under Part 50. These provisions outline what equipment data and compliance monitoring information are required to be maintained for each source subject to Part 50, and provide that the owner or operator must be able to generate a Compliance Data Report (CDR) from the data stored in the data system(s) and submit the report to the Department upon request. Owners and operators have two years from the effective date to develop and implement the required data system. NMED proposed revisions clarifying that the CDR is a report that is distinct from the owner or operator's data system(s) and that the Department does not require access to the data system(s). An owner or operator's authorized representative must be able to access the data system(s) and input data. Monitoring events must be contemporaneously tracked and the data uploaded to the data system(s) in a timely manner. Where specific sections of the rule require a date and time stamp for a monitoring event, Paragraph (8) provides that the Department will finalize a list of approved technologies to comply with the date and time stamp requirements and will post that information on its website within one year of the effective date of Part 50. Owners and operators must comply with the requirement to use an approved technology for date and time stamping within two years of the effective date, and in the meantime can comply with the requirement by making a written or electronic record of the date and time of a required monitoring event. Data in the data system(s) must be maintained for a period of at least five years. NMED Exhibit 32, pp. 25-26; NMED Rebuttal Exhibit 1, pp. 22-24; Tr. Vol. 1358:5 – 1359:14.

These provisions were substantially revised from the Department's initial proposal, which would have required that all sources be equipped with a scannable tag (an "Equipment Monitoring Tag" or "EMT") that would be integrated with a database and used to track equipment information and compliance monitoring events and data. Based on testimony from the industry parties regarding the costs and burdens entailed by the EMT system and integrated database, the Department removed the tagging and scanning requirements and changed the database requirement to a requirement to maintain a data system or systems for tracking and maintaining compliance data and other information for affected sources. Tr. Vol. 5, 1582:14 – 1583:18.

The Board rejects IPANM's proposal to remove these paragraphs in their entirety because NMED engaged in substantial negotiation with industry already and these provisions establish reasonable requirements for all owners and operators subject to Part 50 to operate and maintain a data system where monitoring data, emissions data, and other general information for each affected source can be complied and stored in a manner that allows a report containing the relevant information to be generated and provided to NMED upon request. These requirements are critical to NMED's ability to ensure that affected sources are complying with Part 50 so that reductions in ozone levels predicted by the modeling can actually be achieved. NMED Rebuttal Ex. 1, pp. 22-23.

With regard to the requirement that monitoring events be contemporaneously recorded, the Department has proposed revisions clarifying that only the recording of the event must be contemporaneous; the uploading to the data system does not need to be contemporaneous, but must be done as soon as practicable. The Board rejects the proposals to remove the requirements that each monitoring event be contemporaneously recorded and uploaded to the data system as soon as practicable. This tracking and uploading provides assurance to NMED and the public that compliance monitoring is actually occurring in accordance with the requirements of Part 50. NMED revised this provision to require an owner or operator to include a date and time stamp, including GPS location information, for monitoring events for certain sources. In order to clarify the date and time stamp and GPS requirement, NMED committed to work with stakeholders to identify the technology options that can be used satisfy these requirements. There are multiple options for meeting this requirement, and NMED will not prescribe any specific method for doing so. There are many applications for date and time stamping with GPS, and these applications add the required information to photos and other documents. There are also multiple mobile employee time tracking applications with GPS tracking capability. The new proposed language in this Section requires NMED to finalize a list of approved technologies and post that information on its website no later than one year from the effective date of Part 50.

Based on comments from NMOGA and IPANM, NMED proposed a revised timeline allowing owners and operators subject to these requirements two years from the effective date of Part 50 to begin using one of the Department-approved methods to comply. Tr. Vol. 5, 1582:14-17. Prior to such time, owners and operators may comply with this requirement with a written or electronic record of the date and time of any affected monitoring event. The Board adopts NMED's proposal for the reasons stated in NMED Exhibit 32, pp. 25-26; NMED Rebuttal Exhibit 1, p. 22-24; Tr. Vol. 1358:5 – 1359:14.

Paragraph (9) of Subsection A of Section 20.2.50.112 establishes a requirement for owners and operators to retain a third party at their own expense to verify any information collected, reported, or recorded pursuant to Part 50, if requested by the Department. The third party must conduct an assessment and make recommendations to correct or improve the data collected. The owner or operator is required to share the third-party assessment and recommendations with the Department and implement them in a manner approved by the Department. The third-party compliance verification requirement provides a critical auditing option if the Department suspects or finds that an owner or operator is failing to meet requirements under Part 50. Such verification will benefit the Department's compliance program in significant ways. Having a compliance assessment conducted and a report prepared by an outside third party results in a considerable time and resource savings for NMED, which already operates under limited staffing and financial resources. The Department can review the compliance assessment report highlighting any issues and recommendations, and approve the manner in which the recommendations are implemented. This approach will improve and increase the public's confidence in the company's compliance with Part 50. In sum, the ability of the Department to require a third-party compliance audit strengthens the overall rule; saves limited staffing resources; improves the public's confidence in compliance with the rule; will result in overall better compliance; and provides owners and operators with targeted recommendations on how to improve any compliance issues identified in the report. NMED Exhibit 32, pp. 26-27. For all of these reasons, the Board rejects IPANM's proposal to delete Section (9). *See* also NMED Rebuttal Exhibit 1, p. 24.

The Department incorporated revisions proposed by industry parties requiring that requests for third party audits be based on good cause, to limit such requests to once per year, and to allow an owner or operator to request a hearing to review the Department's asserted cause for requesting a third-party audit and/or the compliance recommendations made by the third party. These revisions provide a remedy if owners and operators do not believe there is good cause for a requested audit, or disagree with the recommendations resulting from that audit. NMED Rebuttal Exhibit 1, p. 24.

The Board adopts the Department's proposal, which was supported in large part by GCA, CDG, and NMOGA, for the reasons stated above. *See also*, as to GCA's support for the removal of EMT requirements, GCA Exhibit 15 (Copeland Direct) at 8-22, GCA Closing Argument pp. 16-18 and proposed SOR 6-9. *See also*, as to CDG's incorporated revisions of "database" to "data system", Tr. Vol. 5, pg. 1471, lines 3-12; p. 1582, line 18 through pg. 1583, line 18. Utilizing the term "data system" rather than "database system" gives owners and operators the flexibility to choose their own data system and to work from their existing software or select some other appropriate software. For small operators, for example, spreadsheets may be acceptable if they track all data points and store and retrieve all information necessary to comply with Section 20.2.50.112. Owners and operators can then readily generate the CDR required by Subsection C of 20.2.50.112. from the information in their data system. In addition, allowing owners and operators to generate their CDRs on July 1st of each year instead of March 1 alleviates the burden on companies during a time when a number of other air quality reports are due to state and federal agencies. CDG NOI Direct Testimony: Lori Marquez, pgs. 2-4; Tr. Vol. 5, 1471:3-12; 1582:18 – 1583:18; 1488:17 – 1493:15; 1583: -1585:20.

Most of NMOGA's proposed revisions were incorporated by the Department; the two remaining proposed clarifications were not accepted by the Board for the reasons stated above. *See also*, as to the bases for NMOGA's support of NMED's commitment to stakeholder engagement in identifying technologies, and the two-year period from the date technologies are identified to finalize implementation, Bisbey-Kuehn Testimony, Tr. 5:1358:24-25 - 1359:1-9; Kuehn testimony, Tr. 5:1370:3-8; Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11; Kuehn testimony, Tr. 5:1356:6-16; NMOGA Exhibit A1, 15:13-25; Smitherman testimony, Tr. 5:1429:14-5:1430:14; and Cooper testimony, Tr. 5:1492:7-5:1493:3.

The Board rejects WEG's proposal to add a standard to this section that prohibits air quality permits or permit revisions for oil and gas facilities that would cause or contribute to ozone levels that exceed 95% of the NAAQS as outside the scope of this rulemaking, and for the reasons expressed by NMED, NMOGA, and CDG.

This proposal is not within the scope of this rulemaking, and is not technically feasible or practical to implement. The purpose of Part 50 is to set emission standards for oil and gas sector equipment and processes, regardless of the permitting status for such equipment and processes. Adopting permitting provisions into this rule is not appropriate at this time, as the consequences of such a revision to New Mexico's permitting program require a full evaluation, including a public comment period for the regulated community and interested stakeholders, as well as discussions with the U.S. Environmental Protection Agency to identify the implications for New Mexico's SIP if such revisions were adopted. The breadth of such a change would best be addressed through a separate rulemaking process and public notice since it is outside of the original scope of the proposed rule. *See* NMED Rebuttal Exhibit 22, pp. 3-4.

The Board and the Department derive their authority to carry out their duties from the enabling statutes that are passed into law by the New Mexico Legislature, including the Environmental Improvement Act, NMSA 1978 74-1-1 to -17, and the AQCA, NMSA 1978, 74-2-1 to -17. As the designated air pollution control agency for the State, the Department must ensure that its SIP, and by extension its regulatory programs, are operated consistent with the federal

Clean Air Act and implementing regulations. This includes the Department's air quality permitting program and the Board's regulations implementing that program, including the following: 20.2.72 NMAC – Construction Permits; 20.2.74 NMAC – Permits – Prevention of Significant Deterioration; and 20.2.79 NMAC – Permits – Nonattainment Areas. Additionally, Section 74-2-7(C) of the AQCA specifies that circumstances under which the Department may deny a permit; there is no authority provided for the Board to specify by regulation additional bases for denial of permits. While the statute allows the Department to deny a permit where it will cause or contribute to air contaminant levels in excess of the NAAQS, it does not provide authority to the Department to deny a permit where it will cause or contribute to air contaminant levels in excess of ninety-five percent of a NAAQS. The Board's regulations relating to air quality permits must be in line with the statute, otherwise they are vulnerable to legal challenges. Id. at 4.

Furthermore, these state statutes and permitting rules have been fully approved by EPA as part of New Mexico's SIP, and give the Department the ability to implement the Clean Air Act in New Mexico on behalf of the federal government. Denying permits contrary to the AQCA and the State's approved SIP endangers the ability of New Mexico to run its own air quality program and issue permits. The Department has not been notified by EPA that any part of its permitting program is inconsistent with the approved SIP or federal law. Id. at 5. *See* also NMED Rebuttal Exhibit 22, pp. 3-5.

WEG failed to demonstrate that the benefit of this reporting would outweigh the burden it would impose on both NMED and industry. Copeland testimony, Tr. 5:1456:24 -5:1457:23. WEG also did not address the Department's concerns that it could not accommodate substantial additional reporting. Mr. Baca testified that WEG's proposal would "overwhelm" the Department," "impose additional burdens that are without any public health benefits," and take the

Department and industry away from the more important work of "addressing issues with compliance that have to do with emissions to the atmosphere." Tr. 5:1592:15; 1593:8-13.

WEG did not demonstrate that its proposal would reduce emissions, provided no estimate of its costs or benefits, and did not show that its proposal could be successfully implemented. The proposal would disrupt the NMED's permitting program by restricting the use of general construction permits in designated attainment areas. The proposal could require individual minor sources to model their single-source ozone impacts. However, this process is not economically feasible and is intentionally not required under current regulations. The proposal would also conflict with federal law by preventing the issuance of Nonattainment Area New Source Review permits to applicants who generate or acquire emissions offsets. *See* CDG NOI Rebuttal Testimony: Marquez, pgs. 1-11.

(10) Where Part 50 refers to applicable federal standards or requirements, the references are to the applicable federal standards or requirements that were in effect at the time of the effective date of this Part, unless the applicable federal standards or requirements have been superseded by more stringent federal standards or requirements.

Paragraph (10) of 20.2.50.112.A clarifies that where Part 50 refers to an applicable federal standard or requirements, the references is to the applicable federal standards or requirements in effect at the time of the effective date of this Part, to guard against situations where referenced federal standards are repealed or amended to be less stringent. The Board adopts this provision because it is necessary to ensure that the department, regulated parties, and the public clearly understand which federal standard or requirement that the Department was referencing, and the Board has adopted, during the development of this Part. If the federal standards or requirements are revised in the future, it also clarifies which version of those requirements should be complied with. NMED Rebuttal Exhibit 1, pp. 24-25.

(11) Prior to modifying an existing source, including but not limited to increasing a source's throughput or emissions, the owner or operator shall determine the applicability of this Part in accordance with 20.2.50.111.B NMAC.

Paragraph (11) of Subsection A of 20.2.50.112 requires owners or operators to review Part 50 for applicability prior to modifying an existing source. The Board adopts this proposal because it is necessary to ensure that owners and operators know of their regulatory obligation to review and confirm applicability or non-applicability of Part 50 when modifying sources that may become subject to Part 50 as a result of such modifications. NMED Rebuttal Exhibit 1, p. 25.

B. Monitoring requirements: In addition to any monitoring requirements specified in the applicable sections of this Part, owners and operators shall comply with the following:
(1) Unless otherwise specified, the term monitoring as used in this Part includes, but is not limited to, monitoring, testing, or inspection requirements.
(2) If equipment is shut down at the time of periodic testing, monitoring, or inspection required under this Part, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

Subsection B of Section 20.2.50.112 specifies general monitoring-related requirements applicable to sources subject to Part 50. Paragraph (1) clarifies what is meant by the term "monitoring" as used throughout the rule. Paragraph (2) provides direction regarding how to comply with monitoring requirements when equipment is shut down at the time of required periodic testing, monitoring or inspection. NMED added language in response to comments from NMOGA allowing an owner or operator's authorized representative to conduct requiring monitoring activities. NMED proposed to remove the provision formerly included at Paragraph (3) addressing submission of an alternative monitoring strategy under Section 20.2.50.116 because such submissions are already addressed in Section 20.2.50.116, making the provision in 20.2.50.112 redundant and unnecessary.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 27; NMED Rebuttal Exhibit 1, pp. 25-26; and in Kinder Morgan's support: because (1) each section of the Proposed Rules contains specific monitoring requirements for that particular equipment or process, and (2) the general monitoring requirement set forth in Section 112 was not intended to be something unique from the other monitoring required in the Proposed Rules, it is appropriate to remove the general provision and rely on the monitoring schedules required in each section.

The Board rejects NMOGA's proposed clarification in B(1) as unsupported by evidence in the record.

C. Recordkeeping requirements: In addition to any recordkeeping requirements specified in the applicable sections of this Part, owners and operators shall comply with the following:

(1) Within three business days of a monitoring event and when final reports are received, an electronic record shall be made of the monitoring event and shall include the information required by the applicable sections of this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years.

(3) By July 1 of each calendar year starting in 2024, the owner or operator shall generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of this Part at the time the CDR is prepared and keep this report on file for five years.

Subsection C of Section 20.2.50.112 establishes minimum universal recordkeeping requirements that owners and operators of sources subject to Part 50 must comply with in addition to the specific monitoring requirements in the applicable sections of the rule. Paragraphs (1) and (2) require that owners or operators make an electronic record of a monitoring event within three business days of the event and to maintain all records required under this part for at least five years. Paragraph (3) requires owners and operators to conduct an annual compliance review for each affected source and certify compliance with all terms and requirements of Part 50. Such certifications must be retained onsite for the specified timeframes.

The annual compliance certification is essential to ensuring compliance with Part 50. *See* Tr. Vol. 5, 1377:2 – 1378:3; 1584:22 – 1585:4. This compliance certification was not meant to be an environmental audit, and it should not require extensive additional resources so long as owners and operators are complying with the monitoring and recordkeeping requirements of Part 50. *See* Tr. Vol. 5, 1583:20 – 1584:21. The annual compliance certification simply requires that such data be complied into an annual report. The Department will provide a template in the form of an Excel spreadsheet to assist smaller companies in complying with the data system and annual compliance report requirements. *See* Tr. Vol. 5, 1362:9 – 1364:12, 1371:8 – 1374:6, 1378:3-17, 1582:14 – 1583:18, 1586:3-23. NMED agreed to strike the provision in Subsection C that required monthly inspections, and instead rely on the monitoring requirements in each section of the rule. *See* Tr. Vol. 5, 1586:25 – 1587:21. NMED also agreed to remove the provision stating loss of data or failure to keep a record shall be treated as a failure to collect the data, because the Department is already able to do this within its enforcement authority. *See* Tr. Vol. 5, 1363:4-8.

The Board adopts this proposal for the reasons stated above and in NMED Exhibit 32, pp. 29-30; NMED Rebuttal Exhibit 1, pp. 26-27; Smitherman testimony, Tr. 5:1429:14-5:1430:14; and Cooper testimony, Tr. 5:1492:7-5:1493:3.

D. Reporting requirements: In addition to any reporting requirements specified in the applicable sections in this Part, the owner or operator shall respond within three business days to a request for information by the department under this Part. The response shall provide the requested information for each source subject to the request 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. If the department requests a CDR from multiple facilities, additional time will be given as appropriate.
[20.2.50.112 NMAC - N, XX/XX/2021]

Subsection D of Section 20.2.50.112 establishes general reporting requirements for sources subject to Part 50. Owners and operators are required to provide requested information to the Department within 3 business days of the request. The requested information must be provided by electronically submitting a compliance data report through the Department's Secure Extranet Portal or by other means and formats specified by the Department in its request. The Department agreed to revisions specifying that additional time will be provided if the department requests a CDR from multiple facilities. The Board adopts this proposal for the reasons stated at NMED Exhibit 32, p. 30 and NMED Rebuttal Exhibit 1, p. 27; as supported in part by NMOGA, and for the reasons stated by GCA: This deadline will ensure that the CDR is promptly generated and submitted to the Department while largely alleviating the potential compliance challenges associated with a 24-hour reporting deadline. GCA Exhibit 15 at 21; and proposed GCA SOR 10-13.

The Board rejects IPANM's proposed deletion of Subsection D as moot, because the Department accommodated most of the requests for implementation date adjustments.

The Board rejects WEG's proposal to add deviation or non-compliance reporting because it creates unclear expectations and creates implantation challenges. A company would have to report simple and inconsequential deviations from the rule's requirements. Specific requirements for reporting and correcting deviations from each section would have to be developed. NMED Rebuttal Exhibit 22, pp. 5-7. The proposed language would also create significant administrative burdens on the Department and the regulated community without commensurate public health protections. Reporting a "deviation" does not ensure that it is corrected, nor do all deviations result in emissions to the atmosphere. The resources expended by industry to comply with the rule and NMED to enforce it are better spent identifying and addressing problems to ensure compliance with the emission standards and that emissions to the atmosphere are minimized.

WEG's proposed changes would require the Department to set up a new system for reporting deviations and processing those reports to determine if a violation has occurred and whether corrective action and enforcement are necessary. NMED does not have the resources to design, deploy, and administer such a system. Instead, the rule sets deadlines for completing repairs for faulty equipment or when leaks are detected, and required regulated entities to keep records which can be provided to the Department upon request.

Sources subject to the Board's excess emissions rules at 20.2.7 NMAC are already required to comply with the provisions of that rule independent of any other requirement. Cross referencing this rule in Part 50 does not provide enhanced compliance incentives for industry, nor does it provide the Department additional tools for increased compliance and enforcement of either rule. *Id.* at 5-6.

Reporting violations of Part 50 would not provide pertinent health information to the public. NMED provides pertinent data to the public through its ozone monitoring network and emissions reporting requirements. This information is readily available on the Department's website and staff routinely respond to more complex external data inquires and requests for other information through the Inspection of Public Records Act, NMSA 1978, 14-2-1 to -12. The Department proposed to require companies to keep extensive records, including date and time stamped records of monitoring and repair events, and produce a Compliance Data Report at any time upon the Department's request. The request for a CDR may be made for any reason, including in response to public inquiries, complaints, or concerns. Limiting these submittals allows NMED to focus its limited resources on ensuring compliance, instead of administrative record keeping. *See* NMED Rebuttal Exhibit 14, regarding recent compliance and enforcement activities, including those related to the Oil and Gas sector. *Id.* at 6-7. Additionally, NMOGA and GCA supported the rejection of WEG's proposal and the Board rejects WEG's proposal based on those parties' rationale as to rejection. *See* GCA Exhibit 30 at 2-7.

20.2.50.113 ENGINES AND TURBINES:

Description of Equipment and Process

Engines and turbines are used in the oil and gas industry to power compressors that maintain natural gas pressures at levels sufficient to move gas through gathering and transmission pipelines. Compressors at gathering compressor stations move the gas from the wellhead to gas processing plants. Compressors at gas processing plants move the gas from the processing plants to transmission pipelines, and compressors at transmission compressor stations maintain pressure and move the gas along the transmission pipelines to the ultimate user of the processed gas.

Engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid or may be used as backup power supply in case of a power outage. Engines are also used to drive pumpjacks in the oil production sector. Pumpjacks are used to mechanically lift liquid out of the well if bottom hole pressure is not high enough to allow liquid to flow to the surface.

Two kinds of reciprocating internal combustion engines are used in the oil and gas industry: spark ignition and compression ignition. The work cycle of both types of engines may either be two-stroke or four-stroke. Reciprocating internal combustion engines are generally used to power reciprocating compressors, and often the engine and compressor share the same crankshaft in what is known as an integral compressor.

A combustion turbine consists of an upstream rotating combustion gas compressor, a combustor, and a downstream turbine on the same shaft as the combustion gas compressor. During operation, the combustion turbine compresses atmospheric air and mixes it with fuel that is burned at extremely high temperatures, creating a hot gas. This hot mixture moves through blades in the turbine, causing them to spin quickly. These blades rotate the turbine drive shaft, which powers the combustion gas compressor. NMED Exhibit 32, pp. 31-32.

Control Options

Readily available options for controlling NOx on two-stroke and four stroke lean burn engines include low emissions controls, selective catalytic reduction, and non-selective catalytic reduction ("SCR"). Readily available NO_X control options for turbines include water or steam injection, dry low-NO_X burners, and SCR. Readily available VOC control options for engines include NSCR and catalytic oxidation. A readily available VOC control option for turbines is catalytic oxidation. *Id.* at 32-36.

Rule Language

The proposed requirements in Section 20.2.50.113 are based on similar rules and standards for new and existing engines and turbines in Pennsylvania GP-5 and GP-5A; California South Coast Air Quality Management District Rule 1110.2; EPA's regulations at 40 C.F.R. § 63, Subpart ZZZZ; 40 C.F.R. § 60, Subpart JJJJ; Colorado Reg. 7, Part E; PA TSD 2018 (NMED Exhibit 52); and EPA Office of Air and Radiation's *Alternative Control Techniques Document – Nox Emissions from Stationary Gas Turbines*, EPA-453/R-93-007 (January 1993) (NMED Exhibit 53). NMED Exhibit 32, pp. 37-46.

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC. Non-road engines as defined in 40 C.F.R. §§ 1068.30 are not subject to 20.2.50.113 NMAC.

Subsection A of Section 20.2.50.113 states the equipment to which this Section applies: portable and stationary natural gas-fired spark ignition engines; compression ignition engines; and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations with a rated horsepower greater than those shown in Tables 1, 2, and 3 of Section 113. The Department accepted NMOGA's proposal to expressly exempt non-road engines as defined by federal regulations because the Clean Air Act preempts state enforcement of emissions standards for such engines. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 37-56, and NMED Rebuttal Exhibit 1, p. 27.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC.

Paragraph (1) of Subsection B of Section 20.2.50.113 requires owners and operators of new and existing portable and stationary engines and turbines equal to or exceeding specified horsepower ratings to meet certain NO_X, CO, and VOC emission limits by certain dates unless otherwise specified under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 37-56, and NMED Rebuttal Exhibit 1, p. 27.

(2) The owner or operator of an existing natural gas-fired spark ignition engine shall complete an inventory of all existing engines subject to this Part by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan (ACP) approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meet the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meet the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

Paragraph (2) of Section 20.2.50.113.B requires owners and operators of existing spark ignited engines to develop an inventory of those engines and meet the emission limits over a specified timeline, unless otherwise specified under an alternative compliance plan or alternative emissions standards are approved. This timeline requires a certain percentage of the inventoried fleet to meet the requirements by specified deadlines. The Board adopts this proposal because the staggered timeline allows owners and operators sufficient time to come into compliance with the requirements of this Section.

In lieu of meeting emissions limits, owners and operators may reduce hours of operation in order to reduce emissions to rates similar to the emissions reduction requirements achieved by utilizing emission control devices. The Board adopts NMED's proposal, supported by NMOGA, because it provides flexibility by allowing an alternative method of compliance for engines that are difficult to retrofit, while ensuring equivalent emission reductions. *See* NMED Exhibit 32, p. 36; NMED Rebuttal Exhibit 1, pp. 27-29. Prior versions of this rule had proposed to regulate "installation" or "relocation." On reflection, the Department removed that language. Kuehn/Palmer testimony, Tr. 6:1686:1-6; Lisowski Rebuttal Testimony, NMOGA Exhibit 43, 1:26-2:3; 6:33-7:13. The "parties are largely in agreement with the new emission standards and thresholds that [NMED] established in this rule." Tr. 6:1682:10-13. NMED revised the tables based on some of the other state programs, such as Pennsylvania's GP-5 program, having other exemptions or off-ramps that were not recognized originally or assumed different fuel types or sizes from those in New Mexico. Kuehn/Palmer testimony, Tr. 6:1701:23-6:1702:5. Mr. Palmer also stated that the department revised the limits based on achievability and cost effectiveness based on the testimony received. Tr. 6:1713:6-11.

There are technical reasons why additional LEC is not available, Tr. 6:1725:17-6:1727:7. Certain retrofit technologies are not widely applicable, Tr. 6:1727:11-6:1728:1, there are limitations of NSCR in the field due to drift and fuel gas variation, Tr. 6:1729:13-6:1730:8, and SCR is generally not effective for oilfield engines, Tr. 6:1730:9-6:1731:9. *See* also Tr. 6:1748:7-6:1749:18, and Tr. 6:1753:15-6:1755:3. NPS argued that the 2.0 g/bhp-hr should be reduced to 1.2 g/bhp-hr, but Mr. Lisowski testified that this was not achievable as a blanket matter and that "there's going to be a large subset of engines in New Mexico that cannot achieve that target and will need to be replaced." Lisowski, Tr. 9:2993:13-18. Mr. Lisowski also explained why, practically, a lower limit was not achievable even with some engines meeting NSPS. Tr. 9:2999:25-9:3001:11.

The Board rejects NPS's proposal to add Section B(2)(e) as submitted late, i.e. not presented at the hearing, and not supported by evidence in the record.

Table 1 - EMISSION STANDARDS FOR EXISTING NATURAL GAS-FIRED SPARK IGNITION ENGINES

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
2 Stroke Lean Burn	>1,000	3.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	2.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	≥1,775 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich Burn	>1,000 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

Table 1 of Paragraph (2) sets forth emission limits for existing natural gas-fired spark ignition engines. NMED originally proposed limits based on standards and data from other states, such as Pennsylvania GP-5 and GP-5A, Colorado Reg. 7, Part E, the California South Coast Air Quality Management District Rule 1110.2, and Ohio EPA test data. *See* NMED Ex. 32, at pp. 37-42. Ultimately, NMED proposed revised emissions limits in Table 1 based on information submitted by NMOGA, Kinder Morgan, and GCA, and a further analysis of stack emissions testing data available from Ohio and the NMED Equipment Data.

The Board adopts NMED's final proposal for the reasons stated in NMED Rebuttal Ex. 1, pp. 29-34, and the reasons set out by industry: NMOGA, Kinder Morgan, and GCA. *See* Lisowksi Rebuttal Testimony, NMOGA Exhibit 43; and Bisbey-Kuehn testimony, Tr. 6:1682:10-13. Although the ultimate proposal is not as stringent as the Department's initial petition, it reflects necessary adjustments based on new information provided by various technical witnesses, including the differing field and gas conditions in New Mexico, off ramps and exemptions found in other regulatory programs not previously considered by the Department, and other technical and economic challenges. Bisbey-Kuehn testimony, Tr. 6:1701:23-6:1702:5. For example, many of the low emitting combustor (LEC) controls are already implemented on existing turbines or else they may be small bore engines where these controls are not practical. Lisowski testimony, Tr. 6:1725:17-6:1727:7. Non-selective catalytic reduction (NSCR), used on many rich burn engines, is already in place and limited in further reduction by drift issues. Lisowski testimony, Tr. 6:1729:13-6:1730:8. Selective catalytic reduction (SCR) is not cost-effective or workable in the oil field as it is too expensive and requires full-time staffing, which is not available at most facilities. Lisowski testimony, Tr. 6:1730:9-6:1731:3.

The National Park Service in its pre-filed testimony requested that emissions limits be established for smaller engines. Multiple experts testified that the proposed limits were not achievable in a cost-effective manner and urged that they not be adopted. *See* Trent, Tr. 6:1814:9-16; Sheldon and Dutton, Tr. 6:1757:1-6:1760:13, Lisowski Tr. 9:2990:20-9:2991:20. Based on this testimony, the NPS withdrew its request to regulate the smaller engines. Devore testimony, Tr. 8:2399:24-8:2400:9. The Board finds that establishing emissions limits for smaller engines as originally proposed by the National Park Service is not supported by the record.

NMED's initial proposal applied 20.2.50.113 NMAC to nonroad engines. NMED revised its proposal so that proposed 20.2.50.113 NMAC does not apply to this class of engines. The Board finds that excluding non-road engines from 20.2.50.113 is proper as these engines are subject to exclusive federal control. 42 U.S.C. § 7543(e); *Engine Mfrs. Ass'n v. U.S. E.P.A.*, 88 F.3d 1075, 1087-88 (D.C. Cir. 1996).

The Department's final proposal included various measures to add flexibility in meeting emissions limits under 20.2.50.113.B NMAC. These include an alternative compliance plan option (20.2.50.113.B(10)), an alternative emission standard allowance in cases of technical impracticability or economic infeasibility (20.2.50.113.B(11)), and the incorporation of the short-term replacement engine substitution concept currently authorized in many air quality permits

(20.2.50.113.B(12). These conditions are technically sound, environmentally protective, and provide flexibility to owners and operators. *See* Tr. 6:1690:7-25 - 1693:1-21.

The Department's final proposal included various measures to clarify the monitoring requirements under 20.2.50.113.C. These include: equivalency between maintenance conducted consistent with an applicable NSPS or NESHAP and maintenance conducted under 20.2.50.113.C(1) NMAC (20.2.50.113.C(2)); load calculation methodologies (20.2.50.112.C(4)); testing timeframes and procedures consistent with New Source Performance Standards (20.2.50.112.C(4)(a)-(h)); and allowance to use carbon monoxide as a VOC surrogate (20.2.50.113.C(4)(i)). These changes were made based on stakeholder feedback and technical testimony. *See* Tr. 6:1694:8-25 - 6:1697:1-7.

Owners and operators will face significant challenges to meet the proposed emission standards, particularly for some existing engines, but the proposed NOx emission standards for existing engines are largely technically feasible and economically reasonable for the majority of engines operated by GCA member companies. Tr. Vol. 6, 1756: 9-19 (Dutton). Selective catalytic reduction is not an economically reasonable control option for most existing engines. Low emissions combustion technology cannot be broadly retrofit to existing engines, and many existing engines already employ the available LEC technology and yet are not able to achieve the NOx emission standards included in the July 2021 draft of the proposed rule. GCA Ex. 12 (Dutton Direct) at 7-10; GCA Ex. 28 (Dutton Rebuttal) at 3-10. The proposed NOx emission standards are consistent with the NOx emissions standards in Pennsylvania general permit GP-5 limit for engines installed between 1997 and 2013. GCA Ex. 28 (Dutton Rebuttal) at 4; NMED Ex. 37 (Pennsylvania Permit GP-5) at 12.

The Board rejects CEP's and NPS's proposal to return to the Department's original Petition for Regulatory Change, which treats all engines or turbines "installed" after the effective date of the rule as "new" equipment subject to more stringent new-source standards; NMED's final tables resulted from extensive negotiation with industry, consideration of additional data, and an understanding of what they could enforce.

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NEW NATURAL GAS-FIRED SPARK IGNITION ENGINES

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	> 500 and < 1875	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥ 1875	0.30 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

Paragraph (3) of Subsection B of Section 20.2.50.113 requires owners and operators of new spark ignited engines to meet the emission limits in Table 2 upon startup. As with Table 1, the Department proposed revised limits in Table 2 based on input from NMOGA, Kinder Morgan, and GCA. The rationale for the revised CO and NMNEHC limits for new engines in Table 2 is the same as that for the revised CO and NMNEHC limits in Table 1, and NMED is proposing the same CO and NMNEHC limits in each.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 37-56; NMED Rebuttal Exhibit 1, pp. 34-35; and supporting evidence from industry: *see* Kuehn/Palmer testimony, Tr. 6:1868:9-22; Lisowksi Rebuttal Testimony, NMOGA Exhibit 43; the testimony of Mr. Brindley, Ms. Nolting and Mr. Trent on behalf of Kinder Morgan, Tr. 6:1807:4-6:1814:8; and GCA's evidence that the proposed NO_X emissions standards and size categories for lean-burn engines are feasible and consistent with what is available on the market for companies seeking to purchase new engines. Tr. Vol. 6, 1749: 3-10 and 1749:20 to 1750:3 (Sheldon).

The Department appropriately changed the NOx emission standards for new engines that were included in the July 2021 draft of the proposed rule, which would not be achievable for some families of new engines, despite the application of best available technology for reducing NOx emissions. Tr. Vol. 6, 1748: 7-17 (Sheldon). Selective catalytic reduction (SCR) is not an economically reasonable control option for most new engines, and is only economically viable for the largest engines that have specific site advantages, such as on-site electrical power and personnel. Tr. Vol. 6, 1753:15 to 1754:21 (Dutton). For those reasons, NMED appropriately raised the size threshold for the application of the most-stringent NOx emission standard from 1,000 horsepower to 1,875 horsepower in its proposal. Tr. Vol. 6, 1749:11-14 (Sheldon); Tr. Vol. 6, 1753:15 to 1754:6 (Dutton). *See also* GCA Closing Argument pp. 6-11 and proposed SOR 27-31.

The Board rejects CEP's and NPS's proposal for more protective standards for existing 4SLBs. for the reasons given by NMED, NMOGA, IPANM, GCA, CDG, and Kinder Morgan. Industry presented extensive and substantial evidence to oppose the NPS revisions: IPANM contracted with Spirit Environmental to review the feasibility of the emission limits proposed by NPS. IPANM Ex. 12 at 17 (Blewitt Rebuttal), IPANM Ex. 13 (Spirit Environmental Report). The report demonstrates that the emission limits proposed by NPS cannot be achieved on a continuous basis. IPANM Ex. 13 at 25 (Blewitt Rebuttal). NMOGA testified that the emission limits in the proposed rule are difficult to attain. NMOGA A1 at 7 (Smitherman Direct). The proposed NOx emission rates in some horsepower ranges result in a single provider situation that can cause a monopoly. *Id.* Kinder Morgan testified that this section of the proposed rule has the potential for greatest impact on Kinder Morgan's operations, particularly with the expense related to meeting the emission limitations. KM Ex. VI at 1 (Brindley Direct, Trent Direct). The GCA expressed concern that some of these emission limits are inconsistent with available technology to retrofit existing engines. GCA Ex. 12 at 4 (Dutton Direct). The GCA was also concerned with the requirement to have the owner or operator of a compressor engine follow a manufacturer-recommended maintenance plan rather than an expert operator-tailored, time-tested and "conditions-based" maintenance plan for which GCA currently operates with. GCA Ex. 15 at 4 (Copeland Direct). Specifically, GCA highlighted how highly incentivized a compression package operator is to properly maintain their "expensive, revenue-generating equipment" and that a generic requirement for maintenance was inappropriate given the incentives already at play. GCA Ex. 15 at 5 (Copeland Direct).

Industry acknowledged that NMED addressed some concerns about compliance of engines that are unable to meet emission standards with the proposed rule by allowing for an Alternative Compliance Plan. The plan would allow operators to determine equivalent amounts of reductions using alternative strategies. The GCA testified that changes NMED had made to the rule satisfied some of the GCA concerns regarding the emission standards for engines. Tr. Vol. 6, 1749:20-1750:3 (Sheldon). GCA highlighted that even with the changes to the rule, there will still be significant challenges to meet the requirements. Tr. Vol. 6, 1756:9-22 (Dutton). Finally, GCA testified in support of NMED's decision not to include the NPS's requested changes based on the Pennsylvania GP-5 permit. Tr. Vol. 6, 1760:7-13 (Dutton). Kinder Morgan also provided an overview of compressor engines. Tr. Vol. 6, 1806:12-1807:18 (Brindley). Kinder Morgan supported many of the Department's changes, but explained that all the retrofits would be a significant cost. Tr. Vol. 6, 1813:23-1814:8 (Trent). CDG reiterated its testimony that this rule mirror NSPS JJJJ for consistency. Tr. Vol. 6, 1841:3-20 (Campsie). *See also* IPANM's proposed SOR 147-173.

Kinder Morgan noted that NPS's proposals were based at least in part on the regulatory requirements of other states, including Colorado and Pennsylvania, but the regulatory programs of those states include exemptions or apply narrowly to certain categories of regulated units such that a blanket adoption of the requirements in New Mexico would not be advisable. Tr. Vol. 6, 1701:12–1702:5. NPS's proposals would also result in unreasonably high costs of compliance. The cost-effectiveness analyses related to the Department's originally-proposed NO_X limits for certain of Kinder Morgan's existing units that will be subject to the Proposed Rules were provided in the Direct NOI, Exhibit VI, at pages 2–6:

- Rio Vista Transmission Compressor Station: Two 1,051 HP turbines, originally subject to 50 ppmvd NOx standard. Costs to control:
    - ~$974,508 per ton of NOx reduced for one unit
    - ~$830,527 per ton of NOx reduced for the other unit
- Caprock Transmission Compressor Station: Two 5,000-7,000 HP turbines; originally subject to 50 ppmvd NOx standard. Costs to control:
    - ~$80,398 per ton of NOx reduced for one unit
    - ~$54,935 per ton of NOx reduced for the other unit
- Monument Transmission Compressor Station: Two, two-stroke lean-burn engines of approximately 1,000 HP; originally subject to 0.50 g/bhp-hr NOx standard. Costs to control:
    - ~$72,527 per ton of NOx reduced for one unit
- ~$125,428 per ton of NOx reduced for the other unit

- Washington Ranch Transmission Compressor Station: Two, two-stroke lean-burn engines of approximately 4,500 HP; originally subject to 0.50 g/bhp-hr NOx standard. Costs to control:
  - ~$10,392 per ton of NOx reduced for one unit
  - ~$30,395 per ton of NOx reduced for the other unit

NPS's proposal would only further exacerbate the cost concerns for the Kinder Morgan's units at Rio Vista and Caprock. NPS also recommended maintaining the originally-proposed standard applicable to the engines at Monument and Washington Ranch. That standard would result in unreasonably high control costs.

NMOGA supported many of the provisions in Section 113: the Department's proposal requires reasonable and aggressive emissions reductions. Industry stakeholders engaged extensively with the Department prior to and during the hearing to reach agreement on appropriate, aggressive standards that both existing and new engines and turbines could meet. There is no "blanket" technology that can meet all needs. Lisowski testimony, Tr. 6:1726:25-6:1727:7. Many of the low emitting combustor (LEC) controls are already implemented on existing turbines or else they may be small bore engines where these controls are not practical. Lisowski testimony, Tr. 6:1725:17-6:1727:7. Non-selective catalytic reduction (NSCR), used on many rich burn engines, is already in place and limited in further reduction by drift issues. Lisowski testimony, Tr. 6:1729:13-6:1730:8. Selective catalytic reduction (SCR) is not cost-effective or workable in the oil field as it is too expensive and requires full-time staffing, which is not available at most facilities. Lisowski testimony, Tr. 6:1730:9-6:1731:3. Based upon this testimony and supporting testimony from Mr. Dutton, Mr. Sheldon and Ms. Witherspoon, NMED, engine and turbine manufacturers, and industry reached an agreement on what is practical for New Mexico. Bisbey-Kuehn testimony, Tr. 6:1682:10-13.

The Department's decision to exclude relocations and like-kind exchanges from the definition of "construction," Bisbey-Kuehn testimony, Tr. 6:1686:1-6, facilitates emissions reductions in the oil field by allowing engines to be "right sized" to the need, preventing them from running below optimal conditions (which would result in higher actual emissions), and allowing for more comprehensive maintenance in the shop as opposed to the field, which helps to keep the overall engine and turbine fleet in better repair. Initial concerns from NPS that old turbines would be "dumped" on New Mexico were ameliorated once they understood that all existing units, including relocated ones, would be subject to the existing source emissions limits. Devore, Tr. 8:2401:2-8:2402:2. CO testing is a good surrogate for VOC testing, because it is cheaper and will enable operators to tune their engines more efficiently. Lisowski, Tr. 6:1734:2-8.

NMED's initial proposal applied to portable engines, which include nonroad engines. NMED revised its proposal so that proposed 20.2.50.113 NMAC does not apply to nonroad engines. The Board excludes nonroad engines from the rule because emissions standards for such engines are subject to exclusive federal control. 42 U.S.C. § 7543(e); *Engine Mfrs. Ass'n v. U.S. E.P.A.*, 88 F.3d 1075, 1087-88 (D.C. Cir. 1996) ("states must be preempted from adopting any regulation for which California could receive authorization."); *Pac. Merch. Shipping Ass'n v. Goldstene*, 517 F.3d 1108, 1113 (9th Cir. 2008) ("we join the D.C. Circuit and hold that the implied preemption of § 209(e)(2) applies to 'any nonroad vehicles or engines,' including new and non-new sources.").

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

Paragraph (4) of Subsection B of Section 20.2.50.113 addresses emissions of unreacted ammonia from SCR systems. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 33-34.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

Paragraph (5) of Subsection B of Section 20.2.50.113 sets emissions standards for compression ignition engines. The proposed NOx emission limit for new compression ignition engines equal to or greater than 500 hp of 9 g/bhp-hr is the same limit as Colorado Reg. 7 Part E, Section II.A.4.e. The emission limit is based on the use of add-on SCR controls. The proposed rule does not include proposed emission limits for existing compression ignition engines. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 43.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

Paragraph (6) of Subsection B of Section 20.2.50.113 addresses emissions of unreacted ammonia from SCR systems. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 33-34.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to Part 50 by July 1, 2023, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(i) by January 1, 2024, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2026, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meet the emission standards.

(iii) by January 1, 2028, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meet the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

Paragraph (7) of Subsection B of Section 20.2.50.113 requires owners and operators of new and existing stationary with rated bhp greater than or equal to 1,000 bhp to meet the NOx and CO emission limits specified in Table 3 by certain dates unless otherwise specified under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. Owners and operators of existing stationary natural gas-fired combustion turbines are required to develop an inventory of those turbines and meet the emission limits in Table 3 over a specified timeline, unless otherwise provided under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. This timeline requires a certain percentage of the inventoried fleet to meet the requirements by specified deadlines.

The Board adopts this proposal because the staggered timeline allows owners and operators sufficient time to come into compliance with the requirements of this Section. Further, in lieu of meeting the emissions limits, owners and operators may reduce the number of hours of operation in order to reduce emissions to rates similar to the emissions reduction requirements achieved by utilizing emission control devices. The Board adopts this proposal because it provides flexibility by allowing an alternative method of compliance for turbines that are difficult to retrofit, while ensuring equivalent emission reductions. *See* NMED Exhibit 32, p. 36; NMED Rebuttal Exhibit 1, pp. 36-37.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable existing natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC:			
Turbine Rating (bhp)	**NO_x (ppmvd @15% O_2)**	**CO (ppmvd @ 15% O_2)**	**NMNEHC (as propane, ppmvd @15% O_2)**
≥1,000 and <4,100	**150**	**50**	**9**
≥4,100 and <15,000	**50**	**50**	**9**
≥15,000	**50**	**50 or 93% reduction**	**5 or 50% reduction**
For each applicable new natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	**NO_x (ppmvd @15% O_2)**	**CO (ppmvd @ 15% O_2)**	**NMNEHC (as propane, ppmvd @15% O_2)**
≥1,000 and <4,000	**100**	**25**	**9**
≥4,000 and <15,900	**15**	**10**	**9**
≥15,900	**9.0 Uncontrolled or 2.0 with Control**	**10 Uncontrolled or 1.8 with Control**	**5**

Table 3 of Paragraph (7) sets forth the emission limits for new and existing stationary combustion turbines. The emission limits and applicability thresholds originally proposed by the Department and the basis for those limits are set forth in the pre-filed direct testimony of Elizabeth Bisbey-Kuehn and Brian Palmer, and were based on the PA TSD 2018 (NMED Exhibit 52), except that the proposed NOx limits for existing turbines were based on EPA Office of Air and Radiation's *Alternative Control Techniques Document – Nox Emissions from Stationary Gas Turbines*, EPA-453/R-93-007 (January 1993) ("EPA 1993 ACT") (NMED Exhibit 53). *See* NMED Exhibit 32, at pages 43-46. NMED proposed revised emissions limits in Table 3 based on information submitted by NMOGA, Kinder Morgan, and Solar Turbines. *See* NMED Rebuttal Exhibit 2, pp. 37-39.

The revised emission limits for NOx in Table 3 for existing turbines equal to or greater than 1,000 hp and less than 4,100 hp (150 ppmvd at 15% O2) are the same limits recommended by Solar Turbines, and similar to the limits in Colorado's Reg. 7 for existing turbines firing natural gas and less than or equal to 50 MMBtu/hr. *See* Tr. Vol. 6, 1689:4-21. The NOx limit for new or reconstructed turbines (100 ppmvd at 15% O2) is similar to the limit for reconstructed turbines in the federal NSPS regulations at 40 C.F.R. 60, Subpart KKKK. NMED accepted Solar Turbine's recommendation to change the upper end of the horsepower cutoff for turbines subject to the 150 ppmvd NOx limit from 5,000 bhp to 4,100 bhp because it would place Solar's Saturn and Centaur 40 4000 turbines, for which Solar reports there is no dry low NOx option, in the small category and the Centaur 40 turbines (with 4,500 bhp and 4,700 bhp ratings) in the middle category for which Solar Turbines reports there is a dry low NOx retrofit option available.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 43-46, and NMED Rebuttal Exhibit 1, p. 39, and as expressed in NMOGA's support: Table 3 limits were derived based on research and comments from manufacturers. Kuehn/Palmer testimony, Tr. 6:1689:4-6:1690:3. Ms. Witherspoon, representing Solar Turbines, testified that the Department's September 16, 2021, table, if corrected to 4,100 bhp for existing turbines, was appropriate and achievable. Tr. 10:3374:6-25.

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

Paragraph (8) of Subsection B of Section 20.2.50.113 addresses emissions of unreacted ammonia from SCR systems. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 33-34.

(9) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

Paragraph (9) of Subsection B addresses emergency use engines as defined by federal law, and imposes a requirement to record hours of operation of such equipment. This requirement is not related to emissions and therefore is not preempted by the CAA. The Board adopts this proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 39 and in Kinder Morgan's Closing Argument, pp. 15-16.

(10) In lieu of complying with the emission standards for individual engines and turbines established in Subsection B of 20.2.50.113 NMAC, an owner or operator may elect to comply with the emission standards through an Alternative Compliance Plan (ACP) approved by the department. An ACP must include the list of engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. Prior to submitting a proposed ACP to the Department, the owner or operator shall comply with the following requirements in the order listed:

(a) The owner or operator shall contract with an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the ACP proposal. The selected firm shall review the proposal to determine if it meets the requirements of this Part, and shall prepare and certify an evaluation of the proposed ACP indicting whether the ACP proposal adheres to the requirements of this Part.

(b) Following the independent third-party review, the owner or operator shall provide the ACP, along with the third-party evaluation and findings, to the department for posting on the department's website. The department shall post the ACP and the third-party review within 15 days of receipt.

(c) Following posting by the department, the owner or operator shall publish a notice in a newspaper of general circulation announcing the ACP proposal,

the dates it will be available for review and comment by the public, and information on how and where to submit comments. The dates specified in the public notice must provide for a thirty-day comment period.

(d) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the ACP proposal and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(e) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the ACP proposal within 90 days. The department shall approve an ACP that meets the requirements of this Part, unless the department determines that the total allowable emissions under the ACP exceed the total allowable emissions under the emission standards of 20.2.50.113 NMAC. If approved by the department, the emission reductions and associated emission limits for the affected engines or turbines shall become enforceable terms under this Part.

Paragraph (10) of Subsection B of Section 20.2.50.113 authorizes an owner or operator to comply with the emissions standards of this Section through an alternative compliance plan or "ACP". This proposal was included at the request of NMOGA and Kinder Morgan, and would provide an alternative to requiring individual sources to meet the emission standards in Part 50. Owners and operators would instead be able to reduce emissions across the entire company fleet, which provides flexibility in the manner in which owners and operators can achieve an equivalent amount of emission reductions in accordance with the same compliance deadlines.

NMED included two additional requirements that are critical for making the ACP concept workable for the Department. First, owners and operators are required to have the ACP reviewed by an independent third-party consulting or engineering firm, which will certify the integrity of the proposal and ensure that the emissions reductions as represented in the proposed ACP are equivalent to reductions achieved by the emissions standards in the rule. Transferring the initial technical review to an outside independent firm will help to alleviate some of the additional burdens on the Department's already constrained resources that will arise from allowing ACPs as means to comply with Part 50. Second, an owner or operator must post the draft ACP for public comment for 30 days and provide notice to the public by publishing a newspaper notice in a newspaper of general circulation. The owner or operator will be required to provide responses to any public comments received to the Department for the Department's consideration in reviewing the ACP. This process will ensure transparency and will provide additional confidence to the Department and the public that a proposed ACP will in fact result in equivalent reductions as would be achieved by the compliance with the emissions standards in the rule. The Board adopts this proposal for the reasons stated in NMED Rebuttal Exhibit 1, pp. 39-40.

(11) The owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. The owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B of 20.2.50.113 NMAC prior to submission of a request for alternative emissions standards under this Paragraph (11), provided that the owner or operator satisfies Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC, below. To qualify for an alternative emission standard, an owner or operator must comply with the following requirements:

(a) Prepare a reasonable demonstration detailing why it is not technically practicable or economically feasible for the individual engine or turbine to achieve the emissions standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, as applicable;

(b) Prepare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner;

(c) Prepare a technical analysis for the affected engine or turbine specifying the emission reductions that can be achieved through other means, such as combustion modifications or capacity limitations. The technical analysis shall include an analysis of any previous modifications of the source and a determination whether such modifications meet the definition of a reconstructed source, such that the source should be considered a new source under federal regulations. The analysis shall include a certification that the modifications to the source are not in violation of any state or federal air quality regulation; and

(d) Fulfill the requirements of Subparagraphs (a) through (c) of Paragraph (10) of Subsection B of 20.2.50.113 NMAC.

(e) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the alternative emission standards and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(f) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the alternative emission standards within 90 days.

If approved by the department, the emission reductions and alternative emission standards for the affected engine or turbine shall become enforceable terms under this Part.

(g) If approved by the department, the emissions reductions and alternative standards for the affected engine or turbine shall become enforceable terms under this Part.

Paragraph (11) of Subsection B of Section 20.2.50.113 allows an owner or operator to request an alternative emission standard for individual engines and turbines that cannot meet equivalent emission reductions under an ACP. This proposal was also included at the request of NMOGA and Kinder Morgan. A request for an alternative emission standard must follow the same process as an ACP. First, owners and operators are required to have the proposed alternative emission standard reviewed by an independent third-party consulting or engineering firm, which will certify the integrity of the proposal and ensure that the emissions standards as represented in the proposal are appropriate for the source. Transferring the initial technical review to an outside independent firm will help to alleviate some of the additional burdens on the Department's already constrained resources that will arise from allowing alternative emission standards as means to comply with Part 50.

Second, an owner or operator must post the draft alternative emission standard for public comment for 30 days and provide notice to the public by publishing a newspaper notice in a newspaper of general circulation. The owner or operator will be required to provide responses to any public comments received to the Department for the Department's consideration in reviewing the proposed alternative emission standard. This process will ensure transparency and will provide additional confidence to the Department and the public that a proposed alternative emission standard will in fact result in an accurate proposal with appropriate reductions from the source. An owner or operator seeking an alternative emission standard for an individual engine or turbine must also demonstrate through an analysis of all past modifications to the unit that the unit has not in fact been modified to the extent that the unit should be considered reconstructed under the Clean Air Act and, therefore, subject to federal standards of performance or other requirements. The analysis must include a certification that the modifications to the source are not in violation of any state or federal air quality regulation.

Paragraph (11) allows the Department to consider individual technical infeasibility demonstrations where certain prerequisites are met, including a demonstration that the emissions of a particular source cannot be addressed through an ACP. The proposal offers significant flexibility for sources that are unable to meet the emission standards of Part 50: they may reduce the annual hours of operation, they may seek an Alternative Compliance Plan to meet an equivalent amount of emission reductions, and/or they may seek alternative emissions standards if they can demonstrate that they cannot meet the existing standards through an ACP. The staggered compliance timeline extends through 2028, giving owners and operators nearly seven years to fully comply with the emission standards. The Board adopts this proposal for the reasons stated in NMED Rebuttal Exhibit 1, pp. 36-37, 40-41, and the supporting argument by Kinder Morgan.

Kinder Morgan notes that without the alternative compliance options in Paragraphs (10) and (11), the emissions standards would be technically infeasible and/or cost-prohibitive in many cases. While the emissions thresholds provided in Tables 1 and 3 for existing engines and turbines are appropriate in most cases, circumstances may exist where it is technically impracticable or economically infeasible to achieve compliance. Cost-effectiveness thresholds above which a certain control technology will be considered infeasible can vary, but, in general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be infeasible. Each technical analysis must include, among other items, a determination of whether any previous modifications of the source cause (or caused) that source to be categorized as a “new” source. Operators should expect to rely on EPA guidance to determine whether a modification has occurred under federal law. *See* Kinder Morgan's Closing Argument, pp. 19-22.

(12) A short-term replacement engine may be substituted for any engine subject to Section 20.2.50.113 NMAC consistent with any applicable air quality permit containing allowances for short term replacement engines, including but not limited to New Source Review and General Construction Permits issued under 20.2.72 NMAC. A short-term replacement engine is not considered a "new" engine for purposes of this Part unless the engine it replaces is a "new" engine within the meaning of this Part. The reinstallation of the existing engine following removal of the short-term replacement engine is not considered a "new" engine under this Part unless the engine was "new" prior to the temporary replacement.

Paragraph (12) of Subsection B allows for the use of short-term replacement engines, as authorized under the Board's regulations for new source review and general construction permits at 20.2.72 NMAC. The Department added this paragraph at NMOGA's request. The Board adopts this proposal because it addresses the need for owners and operators to replace engines on a short-term basis, and align with the authorizations of the permits. *See* NMED Rebuttal Exhibit 1, p. 41, and the supporting evidence from NMOGA: the Department has now proposed standards that are both aggressive and achievable. The Department has also incorporated several crucial changes that eliminate unenforceable standards, provide flexibility, and ensure environmental protection. These include the exclusion of nonroad engines (20.2.50.113.A), the redefining of construction to exclude relocation and like-kind replacement (20.2.50.7.J), extended implementation timelines (20.2.50.113.B.2 and B.7(a)), an alternative compliance plan option (20.2.50.113.B(10)), an alternative emission standard allowance in cases of technical impracticability or economic infeasibility (20.2.50.113.B(11)), and the incorporation of the short-term replacement engine substitution concept currently authorized in many air quality permits (20.2.50.113.B(12). The ultimate proposal by NMED and NMOGA ensures engine and turbine standards maintain "technical practicability and economic reasonableness."

C. Monitoring requirements:

(1) Maintenance and repair for a spark ignition engine, compression ignition engine, and stationary combustion turbine shall meet the manufacturer recommended maintenance schedule as defined in 20.2.50.112 NMAC.

(2) Maintenance conducted consistent with an applicable NSPS or NESHAP requirement shall be deemed to be in compliance with Paragraph (1) of Subsection (C) of 20.2.50.113 NMAC.

(3) Catalytic converters (oxidative, selective, and non-selective) and AFR controllers shall be inspected and maintained according to manufacturer specifications as defined in 20.2.50.112 NMAC, and shall include replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(4) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated within 180 days of the effective date applicable to the source as defined by Paragraphs (2) and (7) of Subsection B of this Section or, if installed more than 180 days after the effective date, within 60 days after achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup of such source. Compliance with the applicable emission standards shall be demonstrated by performing an initial emission test for NOx and VOC, as defined in 40 CFR 51.100(s) using U.S. EPA reference methods or ASTM D6348. Periodic monitoring shall be conducted annually to demonstrate compliance with the allowable emission standards and may be demonstrated utilizing a portable analyzer or EPA reference methods. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\textbf{Load (Hp)} = \frac{\textbf{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\textbf{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\textbf{Load (Hp)} = \frac{\textbf{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\textbf{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

If the manufacturer's rated BSFC is not available, an operator may use an alternative load calculation methodology based on available data.

(a) emissions testing shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(i) The results of emissions testing demonstrating compliance with the emission standard for CO may be used as a surrogate to demonstrate compliance with the emission standard for NMNEHC.

(5) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (4) of Subsection C of 20.2.50.113 NMAC.

(6) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall monitor the hours of operation by a non-resettable hour meter.

(7) An owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(8) Prior to any monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 and 113 NMAC.

Subsection C of Section 20.2.50.113 sets forth monitoring requirements for owners and operators of new and existing engines and turbines. These requirements were revised from NMED's original proposal based on comments submitted by NMOGA and Kinder Morgan. The

Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 36-37; NMED Rebuttal Exhibit 1, pp. 41-43; Tr. Vol. 6, 1693:22 – 1697:7; and for the reasons set out by GCA, below.

GCA supported NMED's proposed engine maintenance schedule requirement in 20.2.50.113(C)(1). NMED's cross-reference to "manufacturer recommended maintenance schedule" as defined in 20.2.50.112 allows for the use of a maintenance schedule that is sufficient to operate and maintain engines in good working order and that has been approved by qualified maintenance personnel based on engineering principles and field expertise. The proposed rule recognizes that an engine manufacturer's minimum recommended maintenance schedule is a one-size-fits-all recommendation that does not account for the actual service and operating conditions of a particular engine, and that engine operators are the true experts in developing and implementing an appropriate maintenance schedule. GCA Exhibit 15 (Copeland) at 3-6. In addition, the cross-reference (along with 20.2.50.113(C)(2)) makes the proposed rule consistent with the applicable federal air rules that govern engines, which allow for maintenance and inspection schedules that have been tailored to a particular engine's service and operation, consistent with good air pollution control practice for minimizing emissions. GCA Exhibit 15 (Copeland) at 6-7.

GCA also supported NMED's proposed catalytic converter inspection and maintenance schedule requirement in 20.2.50.113(C)(3). Catalytic converters used to control engine emissions should not be subject to a monthly inspection requirement, because monthly physical inspections of catalytic converters are unnecessary to ensure continued performance of the catalytic converters and potentially have long-term negative impacts on the catalyst that is used to control emissions. GCA Exhibit 23 (Filby) at 5. NMED's clarification that the requirement for monthly inspections of all control devices required by 20.2.50.115(B)(3) in the proposed rule's general control device provisions is a visual inspection to identify leaks and releases addressed the GCA's concerns regarding the rule's inspection requirements for catalytic converters. Tr. Vol. 6, 1900:13-1901:12 (Filby).

GCA also supported NMED's proposal in 20.2.50.113(C)(4)(i) to allow the results of emissions testing demonstrating compliance with the emission standard for CO to be a surrogate to demonstrate compliance with the emission standard for NMNEHC. For purpose of engine emissions testing, CO serves as a reliable surrogate for NMNEHC, and the New Mexico Air Quality Bureau's permit template language allows permit holders to use engine emissions test results for CO to demonstrate compliance with permit emissions standards for NMNEHC. GCA Ex. 25 (Bartley) at 3-6; Tr. Vol. 6, 1797:12-1798:16 (Bartley). *See also* GCA Closing Argument pp. 11-16 and SOR 39-53.

The Board rejects CDG's proposed revisions to Paragraph (4)(h) and (5) of Subsection C that would require emission testing every 8760 hours or 3 years, to be consistent with NSPS JJJJ; and also rejects NMOGA's similar proposal as to non-emergency engines. The Board rejects these proposals because the requirement to conduct an annual emissions test is reasonable, is necessary to demonstrate compliance with the emissions standards of this section, and is in accordance with the Department's protocol for engine testing for regular construction permits. NMED Rebuttal Ex. 1A, p.1.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and unique identification number for the engine or turbine;

(b) location of the source (latitude and longitude);

(c) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule as defined in 20.2.50.112 NMAC; and

(d) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time stamp(s), including GPS of the location, of an inspection, maintenance, or repair;
(ii) the date a subsequent analysis was performed (if applicable);
(iii) the name of the person(s) conducting the inspection, maintenance or repair;
(iv) a description of the physical condition of the equipment as found during the inspection;
(v) a description of maintenance or repair conducted; and
(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine for a period of five years. The records shall include:

(a) make, model, and serial number for the tested engine or turbine;
(b) the date and time stamp(s), including GPS of the location, of any monitoring event, including sampling or measurements;
(c) date analyses were performed;
(d) name of the person(s) and the qualified entity that performed the analyses;
(e) analytical or test methods used;
(f) results of analyses or tests;
(g) calculated emissions of NOx and VOC in lb/hr and tpy; and
(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine or turbine's actual hours of operation, to demonstrate that an equivalent allowable ton per year emission reduction as set forth in table 1 or table 3 of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC, or the ninety-five percent emission reduction requirement is met.

Subsection D of 20.2.50.113 sets forth specific reporting requirements for owners and operators of new and existing engines and turbines. These provisions include requirements for owners and operators to maintain records of certain information on units subject to this Section, including the make, model, and serial number; a copy of the engine, turbine, and control device manufacturer specifications; information on the initial and annual emissions testing; hours of operation; and information documenting that emissions reductions realized through the reduction in hours of operation is equivalent to a 95% reduction in NOx and VOC emissions. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 37.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.113 NM–C - N, XX/XX/2021]

Subsection E of Section 20.2.50.113 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 37.

Estimated Emissions Reductions Resulting from Section 20.2.50.113

NOx Reductions - Engines

ERG estimated total baseline allowable NOx emissions from all 4,718 operating internal combustion engines located in the Subject Counties, or designated as "Portable." Allowable NOx emissions from those units were 62,005 tpy. ERG then estimated the NOx emission reductions from implementing the proposed regulations on existing engines. Adding controls to uncontrolled engines would reduce NOx emissions by 17,905 tpy, leading to a 28.9% overall reduction in NOx emissions from operating engines from the baseline emissions. *See* NMED Exhibit 56 - ICE Reductions and Costs NO_2 Spreadsheet. Adding controls to uncontrolled engines would reduce NOx emissions by 17,905 tpy, leading to a 28.9% overall reduction in NOx emissions from operating engines from the baseline emissions. *See* NMED Exhibit 32, pp. 46-48; NMED Exhibit 56 - ICE Reductions and Costs NO2 Spreadsheet.

VOC Reductions - Engines

ERG estimated VOC emissions from the entire inventory of 4,276 operating internal combustion engines located in the Subject Counties or designated as "Portable" at 24,224 tpy of VOC. ERG then estimated the VOC emission reductions that would be achieved by implementing the proposed requirements for existing engines. For the 186 uncontrolled engines, ERG estimated reductions of 1,663 tpy of VOC based on the use of an add-on control to achieve the required emission reduction to meet the proposed standard, leading to a 6.8% overall reduction in VOC emissions from existing engines. *See* NMED Exhibit 32, pp. 46-49; NMED Exhibit 57 – ICE Reductions and Costs VOC Spreadsheet.

NOx Reductions - Turbines

ERG calculated the allowable NOx emissions from the entire inventory of 160 active combustion turbines located in the Subject Counties. Emissions from these units total 10,313 tpy of allowable NOx. ERG then examined the effect of implementing the proposed regulations on the 51 unregulated and uncontrolled combustion turbines with a horsepower rating greater than 1,000. Applying controls to these units results in a reduction of 3,377 tpy of allowable NOx. The reductions are based on the percent reductions by engine horsepower rating as indicated above. Adding controls to uncontrolled combustion turbines with horsepower ratings greater than 1,000 would result in a 32.7% overall reduction in NOx emissions. *See* NMED Exhibit 58 – Turbines Reductions and Costs NO_2 Spreadsheet. *See* NMED Exhibit 32, pp. 49-50; NMED Exhibit 58 – Turbines Reductions and Costs NO_2 Spreadsheet.

VOC Reductions - Turbines

ERG estimated the emission reductions from 39 turbines without controls as the difference between the allowable VOC emissions in the permit data and the estimated NMNEHC emissions under the proposed emission limits. The emission reductions are based on the use of an add-on control (oxidation catalyst) to achieve the VOC (NMNEHC) emission limits in the proposed NM standards. Adding controls to these 39 combustion turbines would reduce VOC emissions by 353 tpy, leading to a 49.9% overall reduction in VOC emissions from combustion turbines. *See* NMED Exhibit 32, pp. 50-52; NMED Exhibit 59 – Turbines Reductions and Costs VOC Spreadsheet.

Estimated Costs of Section 20.2.50.113

The annualized costs of NOx emission reductions for the 1,866 uncontrolled and partially controlled natural gas-fired spark-ignition engines were estimated by applying cost equations for the different types and sizes of engines, as described on pages 52-54 of NMED Exhibit 32.

For 2-stroke and 4-stroke lean-burn engines, costs were calculated for adding Low Emission Combustion ("LEC") Technology as a retrofit, as described on pages 53-54 of NMED Exhibit 32, and NMED Exhibit 56. The total annualized costs of adding LEC to lean-burn spark ignition engines and NSCR to rich-burn spark ignition engines was estimated to be $120,267,152 per year, at an average annual cost per engine of $64,452 and a cost per ton of NOx reduced of $6,717.

The annualized costs of VOC emission reductions for natural gas-fired spark-ignition engines were calculated by applying the control costs for adding oxidation catalysts to 172 uncontrolled lean burn engines. Total annualized costs for these 172 engines were estimated at approximately $1,626,842 per year at an average annual cost per engine of $9,458 and a cost per ton of VOC reduced of $990.ERG estimated the total annual costs for internal combustion engines, based on low emission combustion retrofits for lean burn engines at $104 million. NMED Exhibit 32, p. 55.

The annualized costs of NOx emission reductions were estimated for the 51 uncontrolled natural gas-fired combustion turbines, as described on page 55 of NMED Exhibit 32, and NMED Exhibit 58. The total annualized costs of NOx emission reductions for these 51 natural gas-fired turbines were estimated at $13,764,391 per year at an average annual cost per turbine of $269,890 and a cost per ton of NOx reduced of $4,076. *Id.* at 55-56.

To estimate costs of VOC reductions for turbines, ERG assumed that an oxidation catalyst is added as a control device to 39 uncontrolled turbines that are unregulated by an NSPS or NESHAP, and that have allowable VOC emissions that exceed the proposed limits. The total annualized costs of VOC emission reductions for 39 natural gas-fired turbines were estimated at $3,392,186 per year, with an average annual cost per turbine of $86,979 and a cost per ton of VOC reduced of $9,608. *See id.*

Cost estimates were adjusted based on modifications to Section 20.2.50.112 as described in NMED Rebuttal Exhibit 1, pp. 32-33, 38-39, and 44-48.

The Board finds that the estimated costs associated with Section 20.2.50.113 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.114 COMPRESSOR SEALS:

Description of Equipment or Process

Compressors are used throughout the oil and natural gas industry to compress gas for processing, movement through pipelines, and other needs. Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported in pipelines from the production site, through the processing and supply chain, and to the consumer. Vented emissions from compressors occur from seals (wet seal compressors) or packing surrounding the mechanical compression components (reciprocating compressors) of the compressor. These emissions typically increase over time as the compressor components begin to wear and degrade. NMED Exhibit 32, p. 57.

Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by a reciprocating internal combustion engine. Emissions occur when natural gas leaks around the compressor piston rod when pressurized natural gas is in the cylinder. The compressor piston rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. Over time, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder. *Id.* at 57-58.

Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for pipeline transport of natural gas in the natural gas processing and transmission segments of the industry. These compressors require seals around the rotating shaft to prevent high pressure gases from escaping where the shaft exits the compressor casing. Many centrifugal compressors use wet (i.e., oil-filled) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. Other compressors, including most newer compressors, use a dry seal with a mechanical barrier around the rotating shaft to prevent natural gas from escaping. *Id.* at 58-60.

Control Options

VOC emissions from reciprocating compressor rod packing can be minimized by replacing the rod packing on a regular basis before it becomes excessively worn. A typical regulatory schedule is to replace the rod packing seals after every 26,000 hours of operation or every 36 months, whichever is later. A second control option is to collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, a fuel cell, a process stream, or to be used as fuel. Centrifugal compressor seal oil that is contaminated with entrained gas is typically routed directly to an atmospheric pressure degassing tank in which the entrained gas (methane and VOC) will evaporate from the seal oil and is then vented to the atmosphere. NMED Exhibit 32, p. 60.

Centrifugal compressor seal oil that is contaminated with entrained gas is typically routed directly to an atmospheric pressure degassing tank in which the entrained gas (methane and VOC) will evaporate from the seal oil and is then vented to the atmosphere. A wet seal fluid degassing system that is designed to capture the released methane and VOC can be used to separate the entrained gas from contaminated seal oil in a separator and route it to a seal oil demister to remove entrained seal oil before routing the gas to a control device, a process, for use as a fuel, or to the suction side of a compressor to be pressurized and put back into the pipeline or another use. The seal oil from the bottom of the high-pressure seal oil degassing separator flows to the atmospheric degassing separator where the remaining, but now reduced, volume of entrained/dissolved gas is removed and vented to the atmosphere. The regenerated seal oil is then recirculated back to the compressor seal oil system. *Id.* at 61-62.

Rule Language

The proposed requirements in Section 20.2.50.114 are based on similar requirements in NSPS Subpart OOOOa, as discussed in NMED Exhibit 32, pp. 64-65.

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

Section 20.2.50.114 applies to centrifugal compressors using wet seals and reciprocating compressors located at tank batteries, gathering and boosting stations, and natural gas processing plants. Centrifugal compressors and reciprocating compressors located at well sites and transmission compressor stations are not subject to the requirements of Section 20.2.50.114. The Department proposed substantial revisions to this provision based on comments from NMOGA and Kinder Morgan, as outlined in NMED Rebuttal Exhibit 1, pp. 48-50.

NMED proposed to remove transmission compressor stations from applicability of Section 20.2.50.114 based on testimony submitted by Kinder Morgan. NMED estimated VOC emissions from transmission compressor stations using data reported to the GHGRP by operators of those facilities in New Mexico. *See* NMED Rebuttal Exhibit 6 - GHGRP Data for NG Transmission Compression Spreadsheet. The GHGRP data included methane emissions from twelve (12) New Mexico facilities identified as transmission compressor stations. Kinder Morgan's testimony included gas analysis data for five stations showing the average VOC content of their pipeline gas is 0.574%, with a range of 0.206% to 0.775%. *See* Kinder Morgan NOI, Attachment B. Assuming that the methane emissions in the GHGRP data include 0.574% VOC by weight, the total VOC emissions from those twelve stations in the GHGRP is 13 tpy VOC. The range per station is 0.22 tpy to 4.53 tpy VOC. Based on this analysis, NMED agreed that it is appropriate to remove transmission compression stations that are handling pipeline quality natural gas from applicability of this Section. NMED Rebuttal Exhibit 1, pp. 49-50.

The Board adopts NMED's proposal for the reasons stated in NMED Exhibit 32, pp. 62, 64-68; NMED Rebuttal Exhibit 1, pp. 48-50; and the reasons stated by Kinder Morgan in support of NMED's decision to exempt transmission compressor stations from this 20.2.50.114 NMAC addressing compressor seals. The VOC content of the natural gas that Kinder Morgan transports is very low. Detailed analyses of data from Kinder Morgan's operations shows that most of Kinder Morgan's centrifugal wet seals emit 0 or close to 0 tpy of VOC from their degassing vents. Rebuttal NOI, Attachment Z. In light of these low emissions, controlling emissions from existing wet seals would almost certainly be cost-prohibitive. Id. Ex. XIV, at 2–3. Replacing wet seals with dry seals also presents cost concerns and could result in undesirable operational consequences that further exacerbate costs. Id. at 3–4.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor with wet seals shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing, and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

Paragraphs (1) and (2) of Subsection B of Section 20.2.50.114 set forth emissions standards for existing compressors. Owners and operators of existing centrifugal compressors are required to control VOC emissions from centrifugal compressor wet seal fluid degassing systems by at least 95 percent within two years of the effective date of Part 50. Emissions must be captured and routed through a closed vent system to a control device, recovery system, fuel cell, or a process stream. Owners and operators of existing reciprocating compressors must either replace the rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is later, or collect VOC emissions from the rod packing and route them through a closed vent system to a control device, recovery system, fuel cell, or a process stream. For the first option, the owner or operator must begin counting the hours of operation upon the effective date of Part 50. For the second option, the owner or operator has two years from the effective date to implement to begin collecting and routing the emissions. The Department's proposal includes revisions in response to comments by NMOGA. *See* NMED Rebuttal Exhibit 1, p. 49. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 62-63, 64-68; and NMED Rebuttal Exhibit 1, p. 49.

(3) The owner or operator of a new centrifugal compressor with wet seals shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-five percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing and route them via a closed vent system to a control device, a recovery system, fuel cell, or a process stream.

Paragraphs 3 and 4 of Subsection B of Section 20.2.50.114 sets forth emissions standards for new compressors. Owners and operators of new centrifugal compressors are required to control VOC emissions from wet seal fluid degassing systems by at least 98 percent upon startup, capturing and routing emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream. For new reciprocating compressors, rod packing must be replaced after every 26,000 hours of operation or every 36 months, whichever is later, or emissions must be collected from the rod packing using a closed vent system to a control device, a recovery system, fuel cell or a process stream. The Department's proposal includes revisions in response to comments by NMOGA. *See* NMED Rebuttal Exhibit 1, p. 49. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 63, 64-68; and NMED Rebuttal Exhibit 1, p. 49.

(5) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

Paragraph (5) of Subsection B of Section 20.2.50.114 provides that an owner or operator complying with the emissions standards in Subsection B of Section 20.2.50.114 through use of a control device must comply with the control device requirements in 20.2.50.115. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 63, 64-68.

C. Monitoring requirements:

(1) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates as designed and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.114 sets forth specific monitoring requirements for compressors. The Department proposed to delete Paragraph 1 from its most recent proposal because that requirement is redundant with the requirement in former Paragraph 4. Owners and operators complying with the emission standards for reciprocating compressors are required to continuously monitor the hours of operation with a non-resettable hour meter, and track the number of hours from initial startup or from the previous reciprocating compressor rod packing replacement. Owners and operators of reciprocating compressors that are collecting emissions and routing those emissions through a closed vent system to a control device, a recovery system, fuel cell or a process stream are required to monitor the collection system semi-annually to ensure that it continues to operate as designed. Owners and operators must comply with the general monitoring provisions in Section 20.2.50.112. The Department's proposal includes revisions in response to comments by NMOGA. *See* NMED Rebuttal Exhibit 1, p. 49. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 63, 64-68; NMED Rebuttal Exhibit 1, p. 49; and NMOGA Exhibit 43:12:18-21. Mr. Lisowski testified that it is not an issue to install non-resettable meters on compressors and is already used by most operators.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location (latitude and longitude) of the centrifugal compressor;

(b) the date of construction or reconstruction of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the person(s) conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and unique identification number or equivalent identifier of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location (latitude and longitude) of the reciprocating compressor;

(b) the date of construction or reconstruction of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since the effective date, initial startup after the effective date, or the last rod packing replacement, as applicable;

(ii) data showing the effectiveness of the rod packing emissions collection system, as applicable; and

(iii) the time and date of the inspection, the person(s) conducting the inspection, a description of any problems observed during the inspection, and a description of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.114 sets forth recordkeeping requirements for compressors. Owners and operators of centrifugal compressors using wet seal fluid degassing systems are required to maintain records of the following: location of the compressor; date of construction or reconstruction of the compressor; required monitoring data; and the type, make, model and identification number or equivalent identifier of the control device used to comply with the emission standards. Owners and operators of reciprocating compressors are required to maintain a record of the following: location of the compressor; date of construction or reconstruction of the compressor; and the required monitoring data. Owners and operators must comply with the general recordkeeping provisions in Section 20.2.50.112.

The Department's proposal includes revisions in response to comments by NMOGA. NMED Rebuttal Exhibit 1, p. 49. The Department has also proposed additional revisions removing references in this section to "modification," because that term is undefined in the rule and is encompassed within the definition of "reconstruction." The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 62-65, and NMED Rebuttal Exhibit 1, p. 49.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.114 NM–C - N, XX/XX/2021]

Subsection E of Section 20.2.50.114 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 62-63.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.114

ERG's analysis of emissions reductions for compressors is detailed in NMED Ex. 32, pp. 65-68. For the 2,612 reciprocating compressors in the NMED data, total annual emission reductions with increased rod packing replacement were estimated to be 5,325 tpy VOC, a 57.5 percent reduction, and emissions after replacement of rod packing were estimated to be 3,935 tpy VOC. *See* NMED Ex. 64 – Compressor Seals - Reciprocating Engines Spreadsheet. For centrifugal compressors, ERG estimated overall VOC reductions would be 2,087 tpy VOC, and the overall percent VOC emission reduction would be 93%. *See* NMED Exhibit 66 – Compressor Seals - Turbines Spreadsheet.

For reciprocating compressors, ERG estimated the annual cost per compressor for rod packing replacement to be $2,237 per year for a compressor in the gathering and boosting sector, and $1,695 per year for a compressor in the processing sector. These annual costs are incremental costs compared to the annual costs of replacing the rod packing every four years. ERG estimate the total cost for replacing rod packing every three years for all 2,612 reciprocating compressors to be $5,778,289. For centrifugal compressors, ERG calculated the annualized cost for installing a degassing system at each of the 36 locations with centrifugal compressors that would be affected by Part 50 based on the number of compressors at that site, not for each individual compressor. The total initial capital cost for installing a degassing system at the 36 compressor sites is

$2,735,150 and the annualized cost of installing a degassing system at the 36 compressor sites is $667,078. Full details on ERG's cost estimates for compressors can be found in NMED Exhibit 32, pp. 68-70; NMED Exhibit 64 – Compressor Seals – Reciprocating Engines Spreadsheet; and NMED Exhibit 66 – Compressor Seals – Turbines Spreadsheet.

The Board finds that the estimated costs associated with Section 20.2.50.114 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.115 CONTROL DEVICES AND CLOSED VENT SYSTEMS:

Description of Equipment or Process

A control device is any mechanical, thermo, or chemical means to capture, convert, destroy, or recover air contaminants. The purpose of control devices as defined in Part 50 is the reduction of VOCs and NO_X. Some control devices are specific to a particular process or type of equipment, while others can be used for multiple processes or types of equipment. Examples of control devices include, but are not limited to, open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, and catalytic converters (oxidative, selective, and non-selective). A control device may also include any other air pollution control equipment or emission reduction technologies approved by the Department to comply with emission standards in Part 50. NMED Exhibit 32, p. 70.

<u>Open Flares</u>

Open flares or "flaring" refers to the routing of natural gas from anywhere in the process to a device where the gas is combusted as it leaves the tip of the flare. Flaring is a high-temperature oxidation process used to burn or incinerate waste gases containing combustible components such as VOCs, natural gas (methane), carbon monoxide (CO), and hydrogen (H2). Flares convert, or destroy, waste gases into less harmful components (ideally, water vapor and carbon dioxide). The flare system consists of a header, stack, tip, and ignition system. Gas is sent to the flare through a header system and is combusted as it exits the flare stack at the tip. The flare tip is designed to ensure the proper mixing of gas and air to achieve the proper burn efficiency. Ignition of the gas stream is through the use of a continuously burning pilot or auto-ignition system. Flaring is a necessary part of drilling and completion activities, oil and natural gas field production, pipeline gas gathering, and facility processing of oil and natural gas because of safety considerations (personnel and equipment) and its effectiveness in combusting harmful emissions (environmental). *Id.* at 71.

Enclosed Combustion Devices and Thermal Oxidizers

Enclosed combustion devices use a high-temperature oxidation process to control VOCs in many industrial settings because the enclosed combustor can normally handle fluctuations in concentration, flow rate, heating value, and unreactive (i.e., non-combustible) compounds found in the gas stream. For this analysis, it is assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuous basis. Combustion devices can be designed to meet a 98 percent control efficiency, and can control emissions by 98 percent on average, or more in practice when properly operated. Combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions. A typical combustor used to control emissions from storage vessels in the oil and natural gas sector is an enclosed combustion system. *Id.* at 71-72.

Thermal oxidizers – also referred to as direct flame incinerators, thermal incinerators, or afterburners – can also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC-laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted (i.e. vented) to the atmosphere. *Id.* at 72.

Vapor Recovery Units

Vapor recovery units ("VRUs") route vapors from an emission source back to the inlet line of a separator, to a sales gas line, or to another process line for beneficial use, such as use as a fuel. A VRU is often referred to as a compressor that is used to boost recovered vapors back into the line. In a typical VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator or suction scrubber to collect any condensed liquids, which are recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite. *Id.* at 73.

Condensers

A condenser is a heat exchanger used to condense a gaseous substance into a liquid state through cooling. Condensers are often used to control VOC emissions from glycol dehydration units by condensing the organic vapors from the regenerator still vent. *Id.* at 74.

Fuel Cells

A fuel cell is an electrochemical cell that converts the chemical energy of a fuel (typically hydrogen but may also be methane or organic vapors) and an oxidizing agent (commonly oxygen) into electricity through oxidation and reduction reactions that convert the fuel into water vapor (in the case of hydrogen fuel) or into carbon dioxide and water vapor (in the case of methane or organic vapors). The use of fuel cells has been investigated as a potential VOC emission control option for the surface coating industry, but has not yet been demonstrated for controlling VOC emissions from oil and natural gas production operations. *Id.*

Gaseous Emission Control of Stationary Internal Combustion Engines

Gas compressor operations are an essential element of oil and gas production. To produce oil and natural gas and keep natural gas pressures at the level required to move gas from the wellhead to the consumer, compressors and the associated driver are found at multiple locations in the natural gas value chain. In addition to driving compressors, engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid. *Id.*

Catalytic Converters (oxidative, selective, and non-selective)

Stationary engines, typically fueled by natural gas or propane, are widely used for prime power and for gas compression. In gas compression, the types of engines are either rich-burn or lean-burn. The difference between rich-burn and lean-burn engine operation lies in the air-to-fuel ratio: a rich-burn engine is characterized by excess fuel in the combustion chamber during combustion, while a lean-burn engine is characterized by excess air in the combustion chamber during combustion. For gas transmission, engines are typically lean-burning. Gas engines are also used for prime power applications, especially where it is convenient to connect a natural gas line to the engine. Depending on the application, engines in oil and natural gas operations range in size from relatively small (approximately 50 hp) for certain types of pumps and generators to thousands of horsepower for natural gas compressors at transmission compression stations. Different emission control technologies have to be applied to engines depending on their air-to-fuel (A/F) ratio. This is because the exhaust gas composition differs depending on whether the engine is operated in a rich, lean, or stoichiometric burn condition. *Id.* at 74-75.

Rule Language

The proposed general requirements for control devices in Paragraphs (1) through (5) of Subsection B of Section 20.2.50.115.B are based on similar rules for closed vent systems and control devices in Pennsylvania GP-5 and GP-5A (NMED Exhibits 37 and 38), Colorado Reg. 7, Section II.C.5 (NMED Exhibit 39), NSPS Subpart OOOOa (NMED Exhibit 36), and EPA's NSPS regulations at 40 C.F.R. 60, Subpart A – General Provisions. The proposed requirements for closed vent systems for centrifugal compressor wet seal fluid degassing systems in Paragraph (6) of Subsection B of Section 20.2.50.115 are based on Colorado Reg. 7, Section I.J.1; and NSPS Subpart OOOOa, Section 60.5380a. The proposed requirements for open flares in Subsection C of Section 20.2.50.115 are based on NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b). The proposed requirements for enclosed combustion devices and thermal oxidizers in Subsection D of Section 20.2.50.115 are based on Pennsylvania GP-5, Section J; Colorado Reg. 7, Sections I.C.1 and II.B.2; NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b). The proposed requirements for VRUs in Subsection E of Section 20.2.50.115 are based on Pennsylvania GP-5, Section J; and NSPS Subpart OOOOa, Section 60.5412a. *See* NMED Exhibit 32, pp. 78-79.

A. Applicability: These requirements apply to control devices and closed vent systems as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

The requirements of Section 20.2.50.115 apply to control devices and closed vent systems used to comply with the emission standards and emission reduction requirements found in Part 50. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 70-78.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle the reasonably expected range of inlet VOC or NOx concentrations or volumes.

(3) The owner or operator shall inspect control devices visually or consistent with applicable federally approved inspection methods at least monthly to identify defects, leaks, and releases, and to ensure proper operation. Prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(4) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, in order to minimize venting of unburnt gas to the atmosphere.

(5) The owner or operator of a permanent closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, natural gas driven pneumatic pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate the expected range of emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that emissions from the affected equipment are routed to the control device or process; and

(c) have the assessment certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of closed vent system(s) in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system assessment was prepared under my direction or supervision. I further certify that the closed vent system assessment was conducted, and this report was prepared, pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(d) an owner or operator of an existing closed vent system shall comply with the requirements of Paragraph (5) of Subsection B of 20.2.50.115 NMAC within three years of the effective date of this Part and within 90 days of startup for a new closed vent system.

(6) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include the unique identification number, type of unit, manufacturer name, make, model, capacity, and destruction or reduction efficiency data.

Subsection B of Section 20.2.50.115 sets forth general requirements for control devices and closed vent systems. Control devices must be designed and sized to achieve the emission standards required by Part 50, and must be installed, operated, and maintained consistent with manufacturer specifications and good engineering and maintenance practices. Each device must be inspected at least monthly to ensure proper operation, and must operate as a closed vent system that minimizes venting of unburnt gas to the atmosphere. Permanent closed vent systems for the equipment specified in Paragraph (5) of Subsection B must have a design and capacity to accommodate the expected emissions from the affected sources and owners and operators must conduct an assessment to ensure the emissions are routed to the control device or process. This assessment must be certified by a professional engineer or an in-house engineer with relevant expertise. Existing closed vent systems have three years from the effective date to comply with the requirements of Paragraph (5), while new closed vent systems must comply within 90 days of startup. Manufacturer specifications for control devices must be kept on file by the owner or operator and must include identifying information, specific operational parameters (e.g., maximum rated capacity) and control efficiency data. The Board adopts these proposals for the reasons stated in NMED Exhibit 32, pp. 75-76, 78; NMED Rebuttal Exhibit 1, pp. 50-52.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare, and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (c) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following no later than one year after the effective date of this part, unless otherwise specified:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream shall be equipped with a continuous pilot.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(e) the owner or operator shall repair the flare within three business days of any thermocouple or other flame detection device alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto-igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto-igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions;

(d) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of thermocouple, other approved technology, or flame detection device alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the most recent gas analysis for the gas being flared, including VOC content and heating value; and

(e) the date and time stamp(s), including GPS of the location, of any monitoring event.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.115 sets forth specific requirements for open flares. Flares must be sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare and maintain combustion for the duration of time that gas is sent to the flare. Owners and operators using open flares are required to install a continuous pilot, auto-igniter, or require manual ignition no later than one year after the effective date of Part 50 for both new and existing flares. Flares with a continuous pilot flame or auto ignitor must be equipped with a system to ensure that a flame is present at all times when gas is being sent to the flare. Owners and operators of manually ignited flares must inspect and ensure a flame is present upon initiating a flaring event.

Existing flares controlling a continuous gas stream must be equipped with a continuous pilot. For existing flares at facilities with an average daily production of 10 bbls/day of oil or 60,000 scf/day of natural gas, owners and operators are required to install an auto-igniter, continuous pilot, or flare malfunction alarm technology upon replacement or reconstruction. Flares must be operated with no visible emissions except as provided. Flares must be designed so that observers can determine proper operation by visual observations or other means such as continuous monitoring technology, and all repairs must be completed within three business days of an alarm activation.

Flares with a continuous pilot or auto-ignitor must be continuously monitored for the presence of a pilot flame or flame during flaring using a thermocouple equipped with an alarm, and manually ignited flares must be continuously visually monitored for the presence of a flame during a flaring event. Owners and operators are required to perform quarterly EPA Method 22 (40 C.F.R. Part 60, Appendix A) observations to ensure compliance with visible emissions and opacity limits. *See* NMED Exhibit 67 – EPA Reference Method 22 – *Visual determination of Fugitive Emissions from Material Sources and Smoke from Flares* (January 14, 2019). Inspections and monitoring events must be date and time stamped.

Owners and operators must keep records of alarm activation, cause of the alarm, corrective actions taken and name of personnel conducting the action, and any maintenance activities performed. Records must also be kept with respect to EPA Method 22 observations, monitoring of manual flares, and results of gas analyses for the gas being flared. Owners and operators must comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 76-77, 79 and NMED Rebuttal Exhibit 1, pp. 53-54.

The Board rejects the revisions proposed by NMOGA in C(1)(a), C(1)(b), C(3), and C(4) as not clarifying and not supported by evidence in the record.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new ECD/TO with a continuous pilot flame or an auto-igniter upon startup. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than two years after the effective date of this Part.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO. New ECD/TOs shall comply with this requirement upon startup, and existing ECD/TOs shall comply with this requirement within 2 years of the effective date of this Part.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto-igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto-igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(c) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the monitoring requirements of this Part.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of thermocouple, other approved technology, or flame detection device alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activities performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the date and time stamp(s), including GPS of the location, of any monitoring event; and

(d) the results of the most recent gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.115 sets forth requirements for combustion devices and thermal oxidizers ("ECD/TOs"). ECD/TOs must be designed and sized to ensure proper combustion efficiency to gas sent to the equipment. Owners and operators must install continuous pilot flames or auto-igniters upon startup for new ECD/TOs, or within two years of the effective date of Part 50 for existing ECD/TOs. New ECD/TOs must operate with a continuous flame present and with no visible emissions during flaring events upon startup, and existing ECD/TOs must comply with this requirement within 2 years of the effective date.

ECD/TOs with a continuous pilot must be monitored continuously for the presence of a pilot flame. When an auto igniter is used, the presence of a flame must be continuously monitored during flaring using a thermocouple or alternative equivalent technology approved by the Department. Owners and operators are required to perform quarterly EPA Method 22 observations to ensure compliance with visible emissions and opacity limits. Inspections and monitoring events must be date and time stamped.

Owners and operators of ECD/TOs are required to keep records of alarm activation, cause of the alarm, corrective action taken, name of personnel conducting the inspection, and any maintenance activities performed. Additionally, owners and operators must record the results of the quarterly EPA Method 22 observations. Gas analysis results must be recorded for the combustion gas to include the VOC content and heating value.

Owners and operators of ECD/TOs are required to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 77, 79 and NMED Rebuttal Ex. 1, pp. 54-55.

The Board rejects the revisions proposed by NMOGA in C(1)(a), C(1)(b), C(3), and C(4) as not clarifying and not supported by evidence in the record.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime, unless otherwise approved in an air permit issued prior to the effective date of this Part. Alternatively, the owner or operator may shut down and isolate the source being controlled by the VRU. For

sites that already have a VRU installed as of the effective date of this Part, the owner or operator shall install backup control devices or redundant VRUs within three years of the effective date of this Part.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the requirements of this Part.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event, including the name of the person(s) conducting the inspection, any maintenance or repair activities required, and the date and time stamp(s), including GPS of the location, of any monitoring event. The owner or operator shall record the type of redundant control device used during VRU downtime, or keep records of the source shut down and isolated and the time period during which it was shut down, or records of compliance with an air permit issued prior to the effective date of this Part.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

Subsection E of Section 20.2.50.115 sets forth requirements for vapor recovery units. All VRUs must be operated as a closed vent system that captures and routes VOC emissions back to the process or to a sales pipeline. Venting to the atmosphere is prohibited and a backup control device (e.g. flare, ECD,TO) or a redundant VRU is required during periods of startup, shutdown, maintenance, or other downtime such as malfunctions. Based on a proposal by Oxy USA, the Department added a provision allowing a three-year time frame for installation of redundant controls at locations that already have VRUs to accommodate supply chain issues. NMED Rebuttal Ex. 1, p. 56.

Based on proposals by NMOGA, the Department added provisions that authorizes an exemption from the requirement to install a redundant VRU if approved in a state permit, and to authorize owners and operators to shut down and isolate the source being controlled by a VRU in lieu of using a backup VRU during the startup, shutdown, or maintenance of the primary VRU. *Id.* at 55. Owners and operators of VRUs must comply with the monitoring requirements for equipment leaks as specified in Section 20.2.50.116, or implement a program that meets the requirements of NSPS Subpart OOOOa. NMED Exhibit 32, p. 77.

For each VRU inspection or monitoring event, the owner or operator must record the result of the event, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator must also record the type of redundant control device used during VRU downtime. Inspections and monitoring events must be date and time stamped in accordance with the requirements of Part 50. *Id.*

Owners and operators of VRUs are required to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 78-79 and NMED Rebuttal Exhibit 1, pp. 55-56.

The Board rejects the proposed revision by NMOGA in 115.E(1)(a), because it would be contrary to the intent of the rule to capture "all" VOC emissions. Enforcement will turn on an inspector's discretion regarding *de minimis* leakage, and the word "all" is common in regulations. The Board rejects the proposed revisions by NMOGA in 115.E(1)(b), because they are not clarifying; the Air Quality Bureau and industry work together through issues like facility-wide upsets and emergency shutdowns, and it is not necessary to insert an undefined term here. The Board rejects the proposed deletion of E(4) as redundant; redundancy does not pose a problem here.

The Board rejects the proposal by Oxy USA to extend the phase-in schedule from 3 years to 5 years in Section E(1)(b) because the Department already negotiated from immediate compliance to a 3-year phase-in; supply chain issues will not last forever; and in the event three years is truly insufficient time to comply, the Department may be able to handle an extension administratively, or any party can return to the Board with a proposed amendment to the rule based on substantial evidence.

F. Recordkeeping requirements: In addition to the general recordkeeping requirements of 20.2.50.112 NMAC, the owner or operator of a control device or closed vent system shall maintain a record of the following:

(1) the certification of the closed vent system assessment, where applicable, and as required by this Part; and

(2) the information required in Paragraph (6) of Subsection B of 20.2.50.115 NMAC.

Subsection F of Section 20.2.50.115 sets forth recordkeeping requirements for all control devices. Owners and operators must maintain records of a certification of the closed vent system assessment if applicable, and the information required in Paragraph (6) of Subsection B. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 75-79.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.115 NM–C - N, XX/XX/2021]

Subsection G of Section 20.2.50.115 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 75-79.

Estimated Emissions Reductions and Costs Resulting from Section 20.2.50.115

There are no emissions reductions from control devices themselves; rather, control devices are used to reduce emissions associated with the equipment and processes addressed in Part 50. The estimated reductions are therefore discussed in the testimony regarding the proposed requirements for the specific equipment and processes addressed in Part 50. Likewise, the estimated annualized costs of the VOC and NO_X emissions reductions resulting from implementation of Part 50 are discussed in the testimony regarding the proposed requirements for the specific equipment and processes addressed in Part 50. Details on the emissions, costs, and reductions are found in the 'Reductions and Costs' spreadsheets for each of the various equipment and process categories regulated under the proposed rule. These costs are specific to the particular equipment/process and the pollutant being controlled. NMED Exhibit 32, p. 79.

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

Description of Equipment or Process

The processing of natural gas includes the removal of natural gas liquids from field gas and/or the fractionation of mixed liquids to natural gas products. There are a number of potential sources of equipment leaks during production and processing, such as pumps, pressure relief devices, valves, flanges, and other connectors that have a leak potential due to seal failure. In addition, leaks can occur from open-ended lines and valves as well as from corrosion of welded connections, flanges, and valves. The large number of valves, pumps, and other equipment associated with natural gas production and processing can be a significant sources of VOC emissions.

There are also a number of potential sources of fugitive emissions throughout the oil and gas sector. These can occur from poorly fitted connection points or deterioration of seals and gaskets. Fugitive emissions can also be caused by changes in pressure, temperature, or mechanical stresses. A "fugitive emissions component" may be defined as any component that has the potential to emit fugitive emissions at any of the sources previously identified, including valves; connectors; pressure relief devices; open-ended lines; access doors; flanges; closed vent systems; thief hatches or other openings on storage vessels; agitator seals; distance pieces; crankcase vents; blowdown vents; pump seals or diaphragms; compressors; separators; pressure vessels; dehydrators; heaters; instruments; and meters. Devices that would naturally vent as part of normal operations, such as natural gas-driven pneumatic controllers or pumps, are not included as fugitive emissions components. NMED Exhibit 32, p. 80; NMED Exhibit 34.

Control Options

Emissions from fugitive emission sources such as leaking valves, connectors, and flanges can be controlled through implementation of an emission leak detection and repair (LDAR) program. In simple terms, LDAR programs reduce emissions by requiring owners and operators to inspect their facilities to find and repair leaks. Leak detection methods include:

- Audio, visual, and olfactory (AVO) inspections;
- Instrument monitoring according to EPA Reference Method 21, 40 C.F.R. Part 60, Appendix A-7 ("EPA Method 21"); and
- Monitoring using optical gas imaging (OGI).

AVO inspections rely on the use of sight, sound, and smell to identify leaking components by listening for hissing or unusual sounds coming from equipment (audio); looking for cracks, holes, visible liquids leaks, or staining (visual); and smelling for unusual or strong odors (olfactory).

EPA Method 21 is an established reference method that identifies leaks using a portable instrument that can detect the presence of organic gases and measure their volumetric concentration in parts per million (ppm). The method also allows for the use of a soap solution applied to components that will form bubbles if there is a leak present.

OGI is a newer method for leak detection that utilizes forward-looking infrared (FLIR) cameras to conduct inspections of equipment components to identify leaks. OGI infrared cameras are highly specialized thermal cameras that can identify methane using its infrared absorption characteristics. OGI cameras can be used to survey large numbers of components in a short amount of time, whereas EPA Method 21 inspections require inspecting one component at a time with the instrument probe.

When using EPA Method 21, a leak is detected whenever the measured concentration exceeds the defined concentration threshold standard. In Subparagraph (c) of Paragraph (4) of Subsection C of Section 20.2.50.116, this is specified as 500 ppm. When using OGI, a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation.

The control effectiveness of an LDAR program is based on the frequency of monitoring and the leak definition. More frequent monitoring means that leaks are detected and repaired sooner, so that they emit for a shorter time period, and possibly while they are still small and before they grow larger. A lower ppm leak definition will mean that a larger number of leaks must be repaired than with a higher ppm definition. NMED Exhibit 32, pp. 80-82.

Rule Language

The requirements in Section 20.2.50.116 are based on similar rules for LDAR programs for oil and gas sources adopted by Colorado and Pennsylvania, and in NSPS Subparts OOOO and OOOOa, as described in detail in NMED Exhibit 32, pp. 84-86.

A. Applicability: Well sites, tank batteries, gathering and boosting stations, natural gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Components in water or air service are not subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility-wide PTE and in determining the monitoring frequency requirements of this Section.

Subsection A of Section 20.2.50.116 lists the facilities to which this Section applies. The requirements of Section 20.2.50.116 apply to well sites, tank batteries, gathering and boosting stations, natural gas processing plants, transmission compressor stations, and associated piping and components. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC. Tank batteries supporting multiple facilities are subject to the requirements for the most stringently regulated facility of which they are a part.

Subsection B of Section 20.2.50.116 requires owners and operators to perform the monitoring, recordkeeping and reporting activities specified in Subsections C through G. The Department and NMOGA agreed to add a provision addressing tank batteries based on the inclusion of a new definition for that term. *See* Tr. Vol. 4, 1110:2-7, 1121:15-17. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86, and Tr. Vol. 4, 1110:2-7, 1121:15-17.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements:

(1) The owner or operator of a facility with an annual average daily production or average daily throughput of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct an external audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct an external visual inspection for defects, which may include cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors; and

(d) any positive detection during the AVO inspection shall be repaired in accordance with Subsection E if not repaired at the time of discovery.

Paragraph (1) of Subsection C of Section 20.2.50.116 sets forth default monitoring requirements for owners and operators of facilities with an annual average daily production greater than 10 barrels of oil (bbls) per day, or an average daily production greater than 60,000 standard cubic feet per day of natural gas. Owners and operators of these facilities are required to inspect thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components using AVO leak detection method at least weekly.

The frequencies for AVO inspections proposed by NMED are critical to ensuring that the sources are maintained in good working order, operating as intended, and are not causing excess emissions. Liquids from facilities that are primarily oil producing facilities can still be sources of VOC emissions. The existing provisions require reasonable and appropriate AVO inspections to supplement the required LDAR requirements, which occur on a less frequent basis. *See* NMED Rebuttal Ex. 1, p. 58.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86, and the reasons stated by GCA in support: The requirement in the July 2021 draft rule that a leaking component discovered through an AVO inspection be tagged within three calendar days presented significant challenges for GCA companies responsible for providing gas compression services; the sites are often quite remote and are manned most frequently by the customers' personnel. GCA Ex. 15 (Copeland Direct) at 22-23. The final proposed rule retains the obligation to tag and repair leaking components found through AVO inspection, but eliminates the three-day deadline for affixing a visible tag to the leaking component. *See also* GCA Closing Argument pp. 18-19, and SOR 54-57.

(2) The owner or operator of a facility with an annual average daily production or average daily throughput of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an external audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to

identify defects and leaking components as specified in Subparagraphs (a) through (d) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC; except that an owner or operator of a well site within 1,000 feet (as measured from the center of the well site to the applicable structure or area of public assembly) of an occupied area shall conduct the AVO inspection at least weekly.

Paragraph (2) of Subsection C of Section 20.2.50.116 sets forth default monitoring requirements for owners and operators of facilities with an annual average daily production equal to or less than 10 bbls per day, or an average daily production equal to or less than 60,000 standard cubic feet per day of natural gas. Owners and operators of these facilities are required to inspect thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components using AVO leak detection method at least monthly, or, where a well site is within 1,000 feet of an occupied area, at least weekly. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86, with the proposed revisions by NMOGA, which suggested the addition of the final clause. The Board adopts the final clause as consistent with the Board's acceptance of Section 20.2.50.116.C(3)(e) (the "Proximity Proposal") and as supported by NMOGA. *See* Tr. Vol. 8 2708:12-2709:13 (Smitherman testimony). The Board finds the final clause is more protective of public health and the environment, based on substantial evidence.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules, and upon request by the department for good cause shown:

(a) for existing well sites and standalone tank batteries, the owner or operator shall comply with these requirements no later than two years from the effective date of this Part.

(b) for well sites and standalone tank batteries:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(c) for gathering and boosting stations and natural gas processing plants:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

Paragraph (3) of Subsection C of Section 20.2.50.116 requires owners and operators of the following facilities to perform inspections using EPA Method 21 OGI according to the schedules outlined below.

Subparagraphs (a), (b) and (c)

For wellhead sites and standalone tank batteries, owners and operators must conduct inspections annually at facilities with a PTE less than two tpy VOC; semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and quarterly at facilities with a PTE equal to or greater than five tpy VOC. For gathering and boosting stations and gas processing plants, owners and operators must conduct inspections quarterly at facilities with a PTE less than 25 tpy VOC; and monthly at facilities with a PTE equal to or greater than 25 tpy VOC. The Department also proposed an extended compliance period of two years from the effective date of Part 50 for existing wellhead sites and tank batteries, in response to comments raised by Oxy USA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 80-83, 84-90; and the testimony of EDF witnesses Dr. David Lyon (EDF Exhibits RR and XXa, and Tr. Vol. 2537:15 – 2581:18) and Hillary Hull (EDF Exhibits FF and JJJ, and Tr. Vol. 8, 2591:9 – 2635:3).

The Board rejects NMOGA's proposed clarification in Section 116.C(3)(a) as late, i.e. not presented at the hearing, and without support in the record. The Board rejects NMOGA's proposal in Section 116.C(3)(b) and (c), requiring less frequent surveys at higher emission thresholds for well sites and tank batteries, for the reasons given by NMED and CEP, which follow.[3] The Board adopts the proposal for Section 116.C(a), (b), and (c) for the reasons that follow as given by the Department and CEP.

In support of its proposal, NMOGA cited data submitted to EPA by the API in their December 17, 2018 comments on the EPA's October 15, 2018 proposed reconsideration of the Oil and Gas Sector NSPS, based on two years of NSPS Subpart OOOOa leak surveys. The Board finds that these data should not be used to justify less frequent surveys and higher emissions thresholds. NSPS Subpart OOOOa applies to facilities for which construction, modification, or reconstruction commenced after September 18, 2015. Therefore, facilities subject to NSPS Subpart OOOOa were still no more than three years old at the time those NSPS Subpart OOOOa surveys were completed. Those results cannot be considered representative of the existing facilities that will be covered by the requirements of Proposed Part 50, some of which are several decades old. For example, according the NMED Equipment Data the average age of a storage tank in New Mexico is over 10 years old. Standards for "new" sources, as defined in NSPS regulations and proposed Part 50, are intended to apply to sources constructed or reconstructed after a certain date into the foreseeable feature, even after those sources would no longer be considered new in the general sense of that term. NMED Rebuttal Exhibit 1, pp. 63-64.

NMOGA also cited to a recently published peer reviewed research study of upstream leak frequencies to support less frequent surveys at higher emission thresholds. *See* NMOGA Appendix

[3] At the hearing, the Hearing Officer made an evidentiary ruling to exclude evidence offered by NMOGA in support of NMOGA's proposed changes to Section 116.C(3)(b) and (c), concluding that such evidence was not proper surrebuttal, on the basis of unfair surprise to the parties. NMOGA made a proffer of the excluded evidence to the Board, which included: NMOGA's Exhibit 58 (Surrebuttal testimony of John Smitherman regarding proposed 20.2.50.116), pages 10-11, 29 and 52-56, Exhibit 59p "LDAR Gathering & Boosting Incremental Analysis Spreadsheet," and Exhibit 60p "LDAR Well Site Incremental Analysis Spreadsheet." During its deliberations, the Board upheld the Hearing Officer's ruling, finding that the evidence was not proper surrebuttal, on the basis of unfair surprise to the parties.

B at p. 32, citing to "Pacsi, Adam & Ferrara, Tom & Schwan, Kailin & Tupper, Paul & Lev-On, Miriam & Smith, Reid & Ritter, Karin. (2019). Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. *Elem Sci Anth.* 7. 29. 10.1525/elementa.368." The Board cannot properly rely on this study because NMOGA did not provide a detailed comparison of the results of that study to the frequency or emission rates that were the basis of the 2016 CTG estimates of cost effectiveness. NMED Rebuttal Exhibit 1, p. 64.

NMOGA also cited a recent paper commissioned by the U.S. Department of Energy and led by Colorado State University and noted that gathering and boosting sites have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG model plant. Based on this assertion, NMOGA concluded that "less potential for equipment leaks translates to less reductions from a leak detection and repair program." *See* NMOGA Appendix B at p. 32. However, NMOGA failed to note the findings of the study that "the study indicates that study emission factors ***either agree with, or are larger than***, current greenhouse gas reporting program (GHGRP) emission factors for the western U.S." (Emphasis added). NMOGA did not provide any details regarding how the results of the second paper were used to adjust the VOC reduction estimates from those in the 2016 CTG to those in NMOGA's testimony, or how they were used to adjust the cost per ton of VOC reduced. For example, NMOGA relied on the fact that the recent studies have found fewer components and lower leak frequencies in their surveys, and then uses that information in reducing the estimated VOC emission reductions. However, there was no discussion of how the same information would affect the costs of an LDAR program (e.g., fewer components and fewer leaks to repair should also lead to lower costs). The NMOGA analysis also did not take into account the estimated leak rates (in standard cubic feet per hour), including the presence of large emitters relative to those that were the basis of the 2016 CTG estimates. *See* NMOGA Exhibit 7 at page 47. The Board cannot properly rely on the cited study to support less frequent surveys at higher emission thresholds. NMED Rebuttal Exhibit 1, p. 65.

NMED reviewed the two cited papers and agreed that they present useful data on leak frequencies and emission rates. However, other commenters also submitted peer reviewed studies showing that fugitive emissions from oil and gas production may be higher than previously estimated. *See, e.g.*, Environmental Defense Fund ("EDF") Exhibits C, D, E, F, H, I, and J. The Board finds that it is beyond the scope of this rulemaking to conduct a comprehensive literature review of all the recent relevant research on fugitive emissions and establish new cost effectiveness values for LDAR programs specific to the different basins in New Mexico. NMOGA's testimony and comments do not present sufficient data or explanation for Board to determine whether the cost effectiveness values presented in NMOGA Appendix B are based on an analysis that accounts for all of the variables that would actually determine the cost effectiveness of a specific LDAR program. NMED Rebuttal Exhibit 1, pp. 65-66.

NMOGA further argued that the incremental VOC reductions and the cost effectiveness of the proposed LDAR requirements for gas processing plants were not properly calculated, citing the fact that the 2016 CTG cost per ton of VOC was used even though the proposed requirements in Section 20.2.50.116 go beyond the requirements of the 2016 CTG and NSPS Subparts OOOO and OOOOa. NMOGA proposed changes that would allow compliance with NSPS Subpart OOOO or OOOOa, as revised, to satisfy the requirements of Section 20.2.50.116, and that would decrease the frequency of monitoring at those gas processing plants not subject to NSPS Subpart OOOO or OOOOa from quarterly to semiannually for plants with a PTE of VOC less than 25 tpy VOC, and from monthly to quarterly for those with a PTE equal to or greater than 25 tpy VOC.

The Board rejects NMOGA's proposal and finds that it is not appropriate to allow compliance with the LDAR requirements in NSPS subparts OOOO or OOOOa as revised to constitute compliance with Section 20.2.50.116. One of the central purposes of proposed Part 50 is to provide state-level regulations that are not subject to the changes that occur at the federal level. Adopting NMOGA's proposal would give New Mexico no certainty over the future regulatory requirements limiting VOC emissions from equipment leaks at oil and gas facilities in the State. NSPS subpart OOOOa was promulgated in 2016 under the Obama administration, then both NSPS Subparts OOOO and OOOOa were substantially amended in 2020 during the Trump administration, and the 2020 amendments were then disapproved in June 2021 under the Congressional Review Act following the 2020 election. In addition, the NSPS, although it requires monthly checks of pumps and valves at gas processing plants, allows for extended periods of time between checks of connectors, depending on the percent of connectors that are found leaking at any one facility. *See* NMED Rebuttal Exhibit 1, p. 66.

CEP also opposed NMOGA's proposal, noting that NMED's proposed LDAR inspection requirements are necessary to ensure that operators find and fix leaking equipment promptly. The Permian Basin is very leaky. 8 Tr. 2542:5-2547:21 (Lyon). Direct measurement studies conducted in the Permian Basin between 2020 and 2021 demonstrate a leak rate of approximately 3%, which means that oil and gas operators in the Permian Basin leak 3% of the natural gas they produce. This is a higher leak rate than the national average estimated by EDF. 8 Tr. 2549:16-25. "The Permian has some of the highest emissions encountered in -- in the US . . . ." 8 Tr. 2548:5-7 (Lyon). Measurements taken in 2018 at well pads in the New Mexico Permian Basin found high emissions that were "five to nine times higher than estimates based on the EPA National Emissions

Inventory and about 10 times higher than based on the Greenhouse Gas Reporting Program." 8 Tr. 2544:17-21. EDF Ex. XX at 8.

Frequent inspections, using modern leak detection instruments, are necessary to identify leaks such as those commonly found in the Permian Basin. 8 Tr. 2541:1-3, 2546:9-12; EDF Ex. XX at 8. There are several lines of evidence that support frequent inspections as proposed by NMED. First, studies conducted in the Permian Basin as well as other U.S. and international oil and gas basins demonstrate that leaks are intermittent. 8 Tr. 2546:8-12, -2579:10-11; EDF Ex. XX at 7. As Dr. Lyon described: "super-emitters often are intermittent and may occur for a day or hours or even minutes, and -- and they can occur at all sites. So it's critical that sites are inspected to really find these super-emitting sites." 8 Tr. 2548:22-25, -2549:1; EDF Ex. XX at 10. Second, a single large leak or "super-emitter" can release hundreds of tons of pollution to the atmosphere. Super emitters are quite prevalent in the Permian Basin. A recent study using satellites detected over 37 very large leaks in the Permian that each had the potential to release over 4,000 tons per year of methane if left unabated for one year. 8 Tr. 2545:18-22. Another study conducted in August 2021 detected over 900 methane plumes from 500 sources that also could have emitted 200 tons per year of methane if left unabated for one year. 8 Tr. 2546:1-3. Because a single leak can be responsible for hundreds of tons of pollution, according to Dr. Lyon "using the number of leaks is an inappropriate way of estimating emissions or the efficacy of LDAR, I think particularly because it's really the magnitude of the emissions rather than the number of leaks." 8 Tr. 2549:6-10. Third, leaks can re-occur at the same site over time. Many large plumes detected in 2021 at sources in the Permian Basin had also been detected previously at the same sources in 2019. 8 Tr. 2546:4-7. Fourth, frequent inspections can not only detect and help mitigate leaks and super emitters, they can also help operators optimize their operations. 8 Tr. 2586:6-17, -2587:7-15; 10

Tr. 3224:5-18. A number of studies show that poorly maintained or operated equipment or operations can lead to leaks and super emitters. 8 Tr. 2555:1-13.

One of the major sources of super emitters in the Permian and elsewhere are controlled storage tanks that are venting to the atmosphere due to some kind of equipment malfunction. EDF Ex. RR, 4. Another example is a malfunctioning pneumatic controller. 7 Tr. 2225:12 to 7 Tr. 2227:14.

Frequent instrument-based inspections can help an operator identify malfunctioning equipment and other problems that can leak significant amounts of VOCs and methane to the atmosphere. LDAR can help both "looking for equipment leaks, but also looking for underlying problems, including maintenance issues that could lead to future emissions." 8 Tr. 2586:8-12, -2588:9-16 (Lyon). Frequent inspections are necessary to identify stochastic and heterogeneous leaks from poorly operating or maintained equipment and operations, some of which can release hundreds of tons of pollution to the atmosphere per leak, while also helping operators optimize their operations.

AVO inspections are not a substitute for instrument-based inspections. Frequent inspections are only valuable if the methods operators use to look for leaks are reliable. The Department's proposed instrument-based inspections are essential to identifying leaks, including large leaks or super-emitters, as sensory-based AVO inspections do not reliably detect leaks. 8 Tr. 2559:8-15, -2575:14-15; 10 Tr. 3223:15-3224:3, -3225:6-25. AVO inspections are "highly dependent on both the kind of skill and attention of the operator and the conditions in the environment, including things like the wind . . . ." 8 Tr. 2559:10-13; 10 Tr. 3223:19-23. AVO inspections are also flawed because of a lack of verification. "There's no way to really document or verify AVO inspections other than just to take one's word for it and fill out a piece of paper, whereas routine OGI inspections are verifiable, and the evidence is physical and can be documented." 10 Tr. 3223:24-3224:3 (Alexander). AVO cannot reliably detect emissions from malfunctioning pneumatic controllers, 7 Tr. 2228:6-16, or from large emitters such as unlit flares due to the height of the flares. 8 Tr. 2575:14-15 (Lyon).

Low-producing wells can be significant emitters and must be inspected at least annually, as proposed by NMED. The scientific studies, including one conducted in the New Mexico Permian in 2018, show a weak relationship between well pad emissions and production. These studies demonstrate that low-producing wells can emit substantial amounts of VOC emissions, sometimes in excess of the potential to emit, due to malfunctions that cause abnormally high emissions. 8 Tr. 2540:18-2541:3. Frequent inspections with instruments such as optical gas imaging cameras are necessary to mitigate emissions from these low-producing wells. 8 Tr. 2540:18-2541:3.

Three separate studies identified significant leaks from low-producing wells. The first, the 2020 Robertson et al. study, found that wells with production below 10 barrels of oil equivalent per day (BOE/d) had similar emissions as non-marginal wells, based on a comparison of absolute methane emissions and gas production by site. The second study, conducted in 2020 by Deighton et al., found that marginal wells are a disproportionate source of methane and VOCs relative to oil and gas production. The third study, conducted by Omara et al. in 2018, found that low natural gas production sites accounted for 85% of the total number of sites in the study yet were responsible for nearly two-thirds (63%) of the total methane emissions. 8 Tr. 2554:10-25 (Lyon). Many studies identify poor maintenance as a driver of observed methane leakage at marginal sites. These avoidable methane emissions typically are not well represented in traditional emission factor calculations and contribute to the large differences that have often been observed between inventory-based estimates and measurement studies. 8 Tr. 2555:9-18. These studies demonstrate that low production wells are likely a disproportionately large source of oil and gas methane emissions nationally. Mitigating the methane emitted from these sites could reduce a significant proportion of oil and gas methane emissions nationally. 8 Tr. 2555:19-24. Inspecting low-producing wells is essential to curbing emissions from oil and gas facilities. 8 Tr. 2555:19-24.

The Department conservatively estimated the pollution reductions that can be achieved by its proposed LDAR provisions. EDF analysis, based on direct measurements of emissions taken from oil and gas sources in New Mexico as well as other U.S. basins, demonstrates that the proposed inspections will reduce significantly more pollution than ERG estimates. ERG estimated the Department's LDAR proposal would apply to approximately 24,000 well sites in New Mexico and would result in the reduction of 7,131 tons of VOCs per year. NMED Ex. 69; 8 Tr. 2551:3-6. This is a gross underestimate of the pollution from New Mexico well sites that can be reduced by frequent leak inspection and repair requirements based on recent direct measurement studies. EDF Ex. XX at 6-7; 8 Tr. 2551:6-11. A 2018 study conducted by Robertson et al. estimated annual average well pad emissions in the New Mexico Permian Basin are 37 tons methane per year. 8 Tr. 2551:12-15. Using New Mexico gas composition, EDF converted the per well site methane emissions to VOCs. 8 Tr. 2551:16-18. Using these calculations, EDF estimates the average well pad in the Permian emits approximately 11 tons of VOC per year. 8 Tr. 2551:16-18. EDF then applied this per-well VOC emission factor to the 24,000 well sites in New Mexico that are subject to NMED's proposal. This calculation indicates that the total unabated VOC emissions from New Mexico well sites is closer to 260,000 tons of VOCs per year. 8 Tr. 2551:18-20. This is a significantly higher estimate of emissions that can be abated by LDAR inspections than the 7,131 tons of VOCs estimated by ERG estimated.

Direct measurements of emissions from well sites in the Permian Basin indicate that the Department's proposed LDAR requirements underestimate actual emission reductions because ERG grossly underestimated the baseline emissions that can be abated by frequent instrument-based inspections. 8 Tr. 2552:20-25. Other studies conducted in the Permian Basin indicate that Robertson's estimate of well site emissions is actually low, further underscoring the cost effectiveness of the Department's proposed LDAR program. 8 Tr. 2551:21-25; 8 Tr. 2552:1-2. Dr. Lyon refuted NMOGA's assertions that ERG overestimated the reductions associated with the Department's proposed LDAR program. 8 Tr. 2552:12-18. NMOGA based its estimate of emissions reductions on estimates submitted by operators to the EPA pursuant to EPA's Greenhouse Gas Reporting Program. 8 Tr. 2552:3-11.

Direct measurement studies conducted by EDF in the Permian Basin as well as numerous other basins throughout the U.S. demonstrate that emission estimates consistently underestimate measured emissions by significant magnitudes. 8 Tr. 2542:4-8 Tr. 2547:21. A 2018 meta-analysis of the various direct measurement studies conducted by EDF and other scientists concluded that measured U.S. emissions are 70% higher than estimates generated by EPA. 8 Tr. 2549:17-25; 8 Tr. 2550:1. The available scientific studies refute NMOGA's claim that ERG overestimated emission reductions.

The Department's estimate of the costs and VOC reductions associated with proposed 20.2.50.116 are reasonable and, if anything, quite conservative. 8 Tr. 2605:24-2606:4; EDF Ex. JJJ at 6. EDF reviewed ERG's LDAR Reductions and Costs VOC Spreadsheet, NMED Ex. 69. Using more recent inspection cost information than ERG, EDF estimates the per well site cost of conducting semi-annual inspections is $1,658 for semi-annual inspections. This is 30% lower than ERG's estimate. 8 Tr. 2602:13-14. EDF's cost estimate represents the full cost of implementing an LDAR program in-house, which includes LDAR set up costs, survey costs, repair costs, and recordkeeping and reporting costs. 8 Tr. 2602:9-14. ERG relied on site-level data taken from EPA's 2016 Control Techniques Guidelines (CTG) to estimate the costs of conducting annual, semi-annual, and quarterly inspections. 8 Tr. 2602:15-18. EPA assumed $1,318 for annual OGI, $2,285 for semi-annual OGI, and $4,220 for quarterly OGI -- using 2012 dollars. 8 Tr. 2602:18-20. ERG assumed the same costs as assumed by EPA in 2016, except that ERG scaled the costs for inflation using the Chemical Engineering Plant Cost Index from 2012 dollars to 2019 dollars. 8 Tr. 2602:21-24. This resulted in ERG estimates of $1,370 for annual OGI, $2,375 for semi-annual OGI, and $4,385 for quarterly OGI. 8 Tr. 2602:15-15; 8 Tr. 2603:1-4. ERG assumed all sites would conduct semi-annual inspections at an annual cost of $2,375. 8 Tr. 2603:1-4.

A comparison of LDAR compliance costs relied on by the Colorado Air Pollution Control Division for its tiered LDAR program in 2014 and ERG's analysis underscores the conservative nature of ERG's cost estimates. In 2014, Colorado adopted a similar inspection program to that proposed by NMED. 8 Tr. 2603:17-19. Colorado's program, like the Department's proposal, requires differing inspection frequencies based on a facility's emissions. 8 Tr. 2603:19-21. In 2014, Colorado estimated the average cost effectiveness of conducting instrument-based inspections at well sites to be $1,259 per ton for well production facilities. 8 Tr. 2603:22-25. This assumed a tiered program consisting of monthly, quarterly, annual, and once-in-a-lifetime inspections. 8 Tr. 2603:25-8 Tr. 2604:1. While the comparison is not exact, the two estimates indicate the Department's estimate is conservative. 8 Tr. 2604:5-7.

Information submitted by operators to EPA in compliance with EPA LDAR requirements further underscores the likelihood that ERG has overestimated costs. 8 Tr. 2604:8-16. Reports submitted by operators to EPA in 2018 demonstrate that the average time to conduct an LDAR survey is decreasing as the operators have been implementing state and federal LDAR programs. 8 Tr. 2604:8-22. In 2018, M.J. Bradley analyzed approximately 120 reports containing compliance data from LDAR surveys of 3,832 well sites conducted by operators in 2017 and 2018. Of the well sites surveyed, 3,202 contain information on survey time. 8 Tr. 2604:15-16. These reports indicate that average time to conduct an LDAR survey is decreasing as the operators have been implementing state and federal LDAR programs. 8 Tr. 2604:17-20. The reports reviewed by M.J. Bradley indicate an average LDAR inspection takes approximately 1.25 to 1.6 hours per well, including travel time. 8 Tr. 2604:8-22.

Information from a new study demonstrates that inspection times are likely to continue to decrease due to the emergence of even more efficient screening methods such as aerial surveys which operators can use to screen multiple facilities for leaks in a much shorter time frame than can be achieved using ground based OGI methods. 8 Tr. 2604:8-2605:5. The rapid growth in advance methane detection technologies such as aerial surveys is likely to continue to reduce inspection times and thus LDAR compliance costs. 8 Tr. 2604:23-8 Tr. 2605:18. The Department's proposal allows operators to obtain approval to use alternative equipment leak monitoring plans. It is likely many of these plans will rely on a combination of fixed censors, aerial surveys, and satellites. 8 Tr. 2605:18-23. In sum, recent data regarding actual inspection time and the emergence of more efficient LDAR inspection methods indicates that the Department's estimate of the costs associated with conducting ground based OGI or Method 21 vehicle inspections is quite conservative. 8 Tr. 2605:16-2606:4.

NMOGA's proposal would increase the emission thresholds triggering each LDAR tier fivefold compared to NMED's proposal and result in substantial pollution to the atmosphere that can be cost effectively mitigated. EDF Ex. JJJ at 4; 8 Tr. 2608:6-18. EDF's analysis shows that

NMOGA's proposal would result in 23,000 additional tons of VOCs and 79,000 additional tons of methane left unabated annually. EDF Ex. JJJ at 4; 8 Tr. 2608:22-25. NMOGA has significantly over estimated compliance costs for NMED's proposed LDAR requirements. EDF Ex. JJJ at 3; 8 Tr. 2606:6-16. NMOGA's estimate of the costs of conducting inspections is magnitudes higher than estimates conducted by NMED as well as other regulators who have adopted LDAR provisions. NMOGA estimates a per well site inspection cost of $6,400. 8 Tr. 2606:23-24. This is 169% higher than NMED's, 286% higher than EDF's estimate, and 168% to 228% higher than EPA's. EDF Ex. JJJ at 7-8. NMOGA bases this inspection cost, in part, on comments submitted to EPA by API in 2016. 8 Tr. 2606:16-19. EPA rejected the API costs, however, when it finalized its requirements to reduce ozone precursors from oil and gas sources in 2016. 8 Tr. 2607:2-4. Ms. Hull reviewed NMOGA and API's comments and found that API's reasoning was critically flawed and NMOGA's reliance upon this information is misplaced. EDF Ex. JJJ at 7; 8 Tr. 2606:16-2607:9.

API presumed that all operators would create their own in-house LDAR survey program from scratch rather than employ third-party providers. 8 Tr. 2607:5-9. This assumption inflates the cost of implementing an LDAR program. 8 Tr. 2607:8-9. For small operators it is often more economical to hire a third-party contractor to conduct leak inspections than to purchase its own infrared camera and other equipment necessary to conduct inspections. 8 Tr. 2607:10-14. For example, when Colorado first adopted its LDAR program in 2014, it assumed that operators who have less than 500 wells would hire a third-party contractor to conduct LDAR as they would not be able to fully utilize an infrared camera. 8 Tr. 2607:15-19; EDF Ex. BB. API also used basin-level averages to imply that for each survey, an operator would travel approximately 340 miles roundtrip. Ms. Hull testified that this estimate appears "extraordinarily high." 8 Tr. 2607: 20-23;

EDF Ex. JJJ, pp. 7-8. 8 Tr. 2607:25-2608:3. NMOGA provided no support for how, if at all, API's comments to EPA that were rejected by EPA, are applicable to this proceeding. *See* CEP proposed SOR 249-302, 325-357; and CEP's Closing Argument, pp. 34-40.

(d) for transmission compressor stations, quarterly or in compliance with the federal equipment leak and fugitive emissions monitoring requirements of New Source Performance Standards, 40 C.F.R. Part 60, as may be revised, so long as the federal equipment leak and fugitive emissions monitoring requirements are at least as stringent as the New Source Performance Standards OOOOa, 40 CFR Part 60, in existence as of the effective date of this Part.

For transmission compressor stations, pursuant to an agreement with Kinder Morgan and EDF, the Department proposed that the required inspections be done quarterly, or in compliance with the requirements of the federal NSPS so long as those requirements are at least as stringent as those in existence as of the effective date of Part 50. This provision is warranted because more frequent monitoring would not be cost effective due to the low VOC profile of transmission compressor stations. The Board adopts this proposal, and rejects NMOGA's proposal, for the reasons stated in Tr. Vol. 8, 2516:10 – 2519:12, 2444:14 – 2446:15, and the reasons set out below by Kinder Morgan and EDF.

On September 24, 2021, Kinder Morgan and EDF filed a joint proposal for leak detection and repair (LDAR) at transmission compressor stations. Notice of Joint Proposal Regarding Sur-Rebuttal Testimony of Kinder Morgan and EDF (Sept. 24, 2021) ("Joint Proposal"). Under the Joint Proposal, transmission compressor stations, regardless of potential to emit, would be afforded two compliance options for the frequency of monitoring under Paragraph (3) of Subsection C of 20.2.50.116 NMAC: (1) conduct quarterly monitoring, or (2) comply with equipment leak and fugitive emissions monitoring requirements set out in federal NSPS so long as such standards are at least as stringent as the NSPS OOOOa, 40 C.F.R. Part 60, as in existence on the effective date of the Proposed Rules. Joint Proposal, at 1–2.

The Department adopted the Joint Proposal in the December 16 Draft, and retained it in the January 18 Draft. Prior to this change, transmission compressor stations had been subject to the same LDAR inspection frequencies as gathering and boosting stations and natural gas processing plants. *See* Petition, Draft Proposed Rules, 20.2.50.116.C.(3)(b) NMAC. During the hearing, the Department agreed that "the VOC content of natural gas transported by a transmission compressor station is lower – much lower than the VOC content of gas moved in gathering and boosting and at gas plants," Tr. Vol. 8, 2441:24–2442:4, and that "it would be reasonable to treat transmission compressor stations differently than [gathering and boosting stations and natural gas processing plants] with respect to inspection frequency" under the LDAR rule proposal. Id. at 2442:5-9. The Department then stated that it supports the Joint Proposal. Id. at 2444:25–2445:4. The Department also agreed that stringency in the context of an LDAR program is a function of how frequently inspections are required, and that the Department's goal with respect to LDAR at transmission compressor stations is that inspections will be conducted at least quarterly. Hearing Transcript, Vol. 8, 2445:5–2446:15.

Many sources, including many transmission compressor stations, are subject to EPA's LDAR program, and the federal LDAR program may differ from the state LDAR program, creating implementation challenges. Compounding these matters is the fact that the VOC content of natural gas present at a transmission compressor station is very low relative to the natural gas in other segments of the oil and gas industry. To address these issues, the Board should adopts 20.2.50.116.C.(3)(d) NMAC, which affords transmission compressor stations two compliance options for the frequency of monitoring under Paragraph (3) of Subsection C of 20.2.50.116 NMAC: (1) conduct quarterly monitoring, or (2) comply with equipment leak and fugitive emissions monitoring requirements set out in federal NSPS so long as such standards are at least as stringent as the NSPS OOOOa, 40 C.F.R. Part 60, as in existence on the effective date of the Proposed Rules. This approach ensures that transmission compressor stations are monitoring at least quarterly while appropriately managing overlap with the federal LDAR program.

Gathering compressor stations are one of the largest sources of emissions, contributing about 20% of total emissions. 8 Tr. 2546:16-18. Several recent studies have looked at methane emissions from gathering and boosting stations, including an EDF-sponsored study for Colorado State University that used site-level measurements to estimate gathering compressor emissions. Colorado State University has conducted subsequent work looking at component-level emissions and found that compressors can have leaks and anomalous emissions. 8 Tr. 2579:22-2580:6 (Lyon). Recent work by EDF, including aerial surveys by Carbon Mapper, have found that in the Permian Basin, gathering stations are a disproportionately large source of emissions compared to other basins, with the stations themselves accounting for about 25% of the measured methane emissions from large emitters. 8 Tr. 2580:7-13. Many of these emissions are due to both leaks and inefficient operations, including flares that are not properly burned. 8 Tr. 2580:14-19. In the Permian in particular, there are pressure issues where some of the gathering pipelines are over pressurized, and have anomalous pressure relief venting from these gathering stations, causing very high emissions. 8 Tr. 2580:20-24. For this reason, it is critical that the sites are maintained well, including assuring they are operating under proper pressure, to avoid large emissions from gathering compressor stations. Id. 2580:25-2581:4 (Lyon).

It is critical to have frequent LDAR at gathering stations because they can have anomalous very high emission events. 8 Tr. 2581:7-12. Through EDF's analyses, Dr. Lyon has found that these emission events can be short-term, often only a couple hours or days. 8 Tr. 2581:7-12. It is critical to continuously look for problems by doing frequent inspections and, if possible, have some kind of continuous monitoring of these facilities to make sure that when operators notice problems, they are fixed very quickly. 8 Tr. 2581:13-18.

The Department's proposal will reduce significant pollution from compressor stations. The Department's proposal requires quarterly LDAR for gathering compressor stations emitting less than 25 ton per year VOC and monthly LDAR for compressor stations emitting equal to or greater than 25 ton per year VOC. 8 Tr. 2609:5-8. Based on Ms. Hull's analysis, the Department's LDAR requirements for well sites and gathering and boosting compressor stations is highly cost effective and will remove 153,000 tons of VOCs from the atmosphere annually. In addition, the program has a co-benefit of reducing 531,000 tons of methane annually. 8 Tr. 2610:9-14.

NMOGA's proposal would leave thousands of tons of pollution unabated. Ms. Hull estimated the pollution that will be left unabated if the EIB adopts NMOGA's compressor stations LDAR proposal. NMOGA's proposal to decrease the frequency of inspections at well sites and compressor stations would result in the release of thousands of additional tons of volatile organic compounds and methane to the atmosphere annually. These emissions contribute to unhealthy levels of ozone pollution and the climate crisis. 8 Tr. 2594:22-2595:3 (Hull). Compared to the Department's proposal, NMOGA's proposal would decrease the inspection frequency from monthly to quarterly for compressor stations emitting 25 ton per year VOC or more and from quarterly to semi-annually for those emitting below 25 ton per year VOC. 8 Tr. 2609:9-13. Ms. Hull estimates NMOGA's proposal would result in up to 8,400 additional tons of VOC and up to 34,000 additional tons of methane leaked annually using EDF emission estimates that would not be leaked to the atmosphere if the Board adopted the Department's proposal. 8 Tr. 2609:19-25; EDF Ex. JJJ at 5.

NMOGA's proposal to reduce the frequency of leak inspections at compressor stations would result in a 20% decrease in emission reductions from gathering and boosting sites. EDF Ex. JJJ at 3 (Hull). Frequent LDAR, as the Department has proposed, can effectively curb the unhealthy levels of ozone pollution that form in part from oil and gas operations, including from compressor stations. 8 Tr. 2595:4-5.

(e) quarterly at well sites within 1,000 feet of an occupied area.

The Department proposed that the Board adopt the proposal of CAA and EDF to require enhanced inspection frequencies for well sites within 1,000 feet of an occupied area as defined in Part 50 (the "Proximity Proposal"). Inspections would be required quarterly. The Board adopts the Proximity Proposal for the reasons presented by CAA, EDF and OXY USA, and supported by NMED, as amended by NMOGA, for the reasons given by NMOGA. The amendment removes the original proposal's requirement for monthly inspections at facilities with a PTE equal to or greater than five tpy VOC, maintaining quarterly inspections for all well sites within 1,000 feet of an occupied area, which generally include homes, businesses, schools, and parks. The Board accepts NMOGA's proposed revisions to the Proximity Proposal to mitigate NMOGA's concerns about cost effectiveness. *See* NMOGA Exhibit 58 at 48 (Smitherman Testimony).

The Board rejects the arguments from NMOGA and IPANM that it is without authority to adopt the LDAR Proximity Proposal. The Board finds based on substantial evidence that the Proximity Proposal presented by CEP and OXY, supported by NMED, and amended by NMOGA, is more protective of public health and the environment.

The supporting evidence for the Proximity Proposal is in the testimony of EDF witness Dr. Tammy Thompson (EDF Exhibit TT, and Tr. Vol. 2717:11 – 2729:2, 2735:20 – 2741:11); CAA witness Lee Ann Hill (CAA Exhibit 25, and Tr. Vol. 9, 2836:21 – 2847:1, 2849:20 – 2858:25);

CAA Ex. 26 at 17 [Joint Proposed Second Revised Amendments to Proposed 20.2.50 NMAC]; and Oxy Reb. Ex. 1 at 16.

Implementation of the Proximity Proposal will help keep New Mexico in compliance with federal ozone standards and has the co-benefits of reducing methane, a potent greenhouse gas, and reducing air pollutants harmful to human health. People who live, work, and play in close proximity to oil and gas operations are at higher risk of suffering from adverse health impacts due to exposure to pollutants emitted from oil and gas operations. In New Mexico, substantial numbers of persons of color, Native Americans, and vulnerable individuals live within 1,000 feet of well sites, many of whom already suffer from health conditions that can be exacerbated by exposure to additional pollution from oil and gas sources. The benefits of this proposal are great while the costs are reasonable. The proximity proposal will reduce VOCs and help New Mexico stay in attainment with federal health-based standards for ozone

The Proximity Proposal will reduce volatile organic compounds that contribute to ozone pollution, thereby helping New Mexico protect clean air and remain in attainment with the NAAQS for Ozone. EDF Ex. TT at 3. EDF estimates that the Proposal will impact 3,365 or 7.7% of the sites in the state, will reduce VOC emissions by 3,600 tons per year, and will increase VOC emissions reductions at those sites by 73%. These reductions in VOCs will help New Mexico reduce local formation of ozone and help New Mexico stay in attainment of the NAAQS for ozone. 8 Tr. 2718:6-22, -2595:19-20.

Air pollutants hazardous to human health, the environment, and the climate — including greenhouse gases, hazardous air pollutants, and criteria air pollutants — are emitted from upstream oil and gas development sites. CCA Ex. 25 at 1 [Hill Reb. Test.]. Air pollutants emitted directly from oil and gas facilities may also contribute to the secondary formation of air pollutants in the atmosphere that also pose risks to human health and the environment (e.g., ground-level ozone). CCA Ex. 25 at 1.

At least 61 HAPs have been measured near upstream oil and gas sites or investigated from secondary data sources in the peer-reviewed literature. HAPs emitted from oil and gas facilities include benzene which is a known human carcinogen, toluene, ethylbenzene, xylene, and n-hexane. CCA Ex. 25 at 7-9. The risks to human health from VOCs emitted from oil and gas facilities are many and varied and include harm to the central nervous system, eyes, skin and respiratory tracts, as well as the liver, kidney, and endocrine systems. CCA Ex. 25 at 7-9.

Persons living, working, and going to school near oil and gas facilities are at greater risk due to emissions of air pollutants. Chronic or long-term exposure to VOCs, NOx, and ground-level ozone may result in longer lasting or more severe public health consequences. Generally, the duration of exposure is a key factor that influences the development of adverse health outcomes. CAA Ex. 25 at 10. There is a reasonable degree of scientific certainty that living in close proximity to oil and gas facilities results in increased health risks and impacts from elevated air pollution levels and that these health risks are increasingly attenuated further from these operations. CAA Ex. 25 at 2, 11. The public health risks and impacts associated with air pollutant emissions from oil and gas facilities that go unaddressed would be disproportionately experienced by people who live, work, and go to school near oil and gas facilities. CAA Ex. 25 at 2-3.

Peer-reviewed air quality health risk assessment studies indicate cancer and noncancer health risks increase with increasing proximity to oil and gas development sites. CAA Ex. 25 at 14. The scientific literature points to the need for frequent if not continuous leak detection using modern and advanced leak detection methods capable of identifying leaks. EDF Ex. RR at 8. The body of epidemiological literature strongly supports that geographic proximity to active oil and gas development is an important risk factor for a variety of adverse health outcomes, including: respiratory outcomes, cardiovascular outcomes and cardiovascular disease indicators, childhood cancer, hospitalizations, and adverse birth outcomes. CCA Ex. 25 at 1, 14-15.

The increased frequency of LDAR inspections within 1,000 feet of "occupied areas" proposed by the Community and Environmental Parties, the Environment Department, and Oxy at 20.2.50.116 NMAC is a targeted strategy to increase public health protections. The proximity proposal will protect the health of vulnerable persons living near oil and gas facilities, some of whom already suffer from adverse health conditions. EDF estimates that the proposal will protect the health of over 35,000 New Mexicans living within 1,000 feet of a wellsite. Of those, over 2,700 are children under the age of 5, more than 4,500 are adults 65 years or older, more than 5,700 are living in poverty, and 19,000 are people of color, including over 5,800 Native Americans. EDF Ex. SS at 15.

Many of these people already suffer from health conditions that could be exacerbated by exposure to additional air pollution. These include more than 3,800 adults with asthma, over 2,200 adults with coronary heart disease, almost 2,600 with chronic obstructive pulmonary disease, and more than 1,200 adults who have experienced or are at risk of a stroke. EDF Ex. DD; EDF Ex. SS at 15; 8 Tr. 2596:23-2597:4. Many people living within 1,000 feet of a well site in New Mexico are people of color and Native Americans. 8 Tr. 2626:14-16. People of color and Native Americans in New Mexico are at a disproportionately higher risk of health conditions exacerbated by air pollution, which includes asthma, heart disease and cancers. 8 Tr. 2624:16-24, 2626:17-21.

The Proposal's LDAR requirements are highly cost effective when calculating the compliance costs divided by the VOC reductions. The Proposal will increase annual emissions reductions by 3,600 tons of VOC. 8 Tr. 2595:19-20. This represents an incremental increase in

LDAR costs of $4.8 million (or 13% higher) from the Department's initial proposal, and results in an average cost of $894 per ton VOC reduced within the proposed 1,000 foot boundary (or $349 per ton VOC reduced statewide). EDF Ex. DD; EDF Ex. SS at 4-5; 8 Tr. 2595:19-20. A review of other jurisdiction's LDAR requirements demonstrates that an average cost of $894 per ton of VOC reduced is very reasonable, as other jurisdictions have adopted LDAR requirements with significantly higher compliance costs. 8 Tr. 2599:2-2600:1. The costs to implement the Proximity Proposal are economically feasible and entirely reasonable. 10 Tr. 3214:19-22.

In summary, the Proximity Proposal is beneficial for several reasons:

- The Proximity Proposal will reduce volatile organic compounds that contribute to ozone pollution, thereby helping New Mexico protect clean air and remain in attainment with the National Ambient Air Quality Standards for Ozone. EDF Ex. TT at 3.
- The Proximity Proposal results in the co-benefits of reducing methane and HAPs emissions. The proximity proposal will secure important co-benefits by reducing 14,300 tons of methane and 150 tons of hazardous air pollutant annually. 8 Tr. 2593:21-23; EDF Ex. SS at 11.
- Air pollutants hazardous to human health, the environment, and the climate — including greenhouse gases, hazardous air pollutants, and criteria air pollutants — are emitted from upstream oil and gas development sites. CCA Ex. 25 at 1.
- There is a reasonable degree of scientific certainty that living in close proximity to oil and gas facilities results in increased health risks and impacts from elevated air pollution levels and that these health risks are increasingly attenuated further from these operations. CAA Ex. 25 at 2, 11.

- The Proximity Proposal will protect the health of vulnerable persons living near oil and gas facilities. EDF estimates that the proposal will protect the health of over 35,000 New Mexicans living within 1,000 feet of a wellsite. EDF Ex. SS at 15.
- The Proximity Proposal's LDAR requirements are highly cost effective when calculating the compliance costs divided by the VOC reductions. EDF analysis and a comparison of the cost effectiveness of the proximity proposal to similar inspection requirements adopted by other air quality agencies support the cost effectiveness of the proposal. 10 Tr. 3214:19-22. *See* also CEP proposed SOR 122-152.

(f) for existing wellhead only facilities, annual inspections shall be completed on the following schedule: 30% by January 1, 2024; 65% by January 1, 2025; and 100% by January 1, 2026.

For existing wellhead only facilities, the Department is proposing that owners and operators conduct annual inspections that beginning after the effective date of Part 50 according to the specified phase-in schedule. This language was included based on a proposal by Oxy USA in lieu of Oxy's previous proposal to entirely exempt such facilities from the LDAR requirements. The Board adopts this proposal for the reasons stated in Tr. Vol. 8, 2524:18 – 2526:24.

(g) for inactive well sites:

(i) for well sites that are inactive on or before the effective date of this Part, annually beginning within six months of the effective date of this Part;

(ii) for well sites that become inactive after the effective date of this Part, annually beginning 30 days after the site becomes an inactive well site.

For inactive well sites, NMED is proposing annual inspections beginning within 6 months of the effective date of Part 50 for well sites that are inactive on or before the effective date. For well sites that become inactive after the effective date, the requirement to conduct annual inspections would begin 30 days after a site becomes an inactive well site. This language was also included based on a proposal by Oxy USA. The Board adopts this proposal for the reasons stated in Tr. Vol. 8, 2524:18 – 2526:24, and rejects NMOGA's proposed revisions for lack of supporting evidence in the record.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of use by the procedures specified in U.S. EPA method 21 and the instrument manufacturer; and

(b) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbons, and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

Paragraph (4) of Subsection C of Section 20.2.50.116 requires that instruments used in inspections using EPA Method 21 must be calibrated pursuant to the procedures specified in that method, as well as by the instrument manufacturer, before each day of use. Regulated leaks are defined as those with a measurement of 500 ppm or greater of hydrocarbons and that are not associated with normal operations. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 84-86, and NMED Rebuttal Exhibit 1, pp. 60-61.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18; and

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

Paragraph (5) of Subsection C of Section 20.2.50.116 requires that inspections using OGI must comply with the requirements in EPA's regulations at 40 C.F.R. Section 60.18. Under this method, a leak is deemed to exist if the emission images recorded by the OGI instrument are not associated with normal equipment operation. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface;

(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; and

(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.

Paragraph (6) of Subsection C of Section 20.2.50.116 provides that components that are difficult, unsafe, or inaccessible to monitor are not required to be inspected until it becomes feasible to do so. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86, and NMED Rebuttal Exhibit 1, p. 61.

(7) Owners and operators of well sites must conduct an evaluation to determine applicability of Subparagraph (e) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC within 30 days of constructing a new well site, and within 90 days of the effective date of this Part for existing well sites.

(8) An owner or operator conducting an evaluation pursuant to Paragraph (7) of Subsection C of Section 20.2.50.116 NMAC shall measure the distance from the latitude and longitude of each well at a well site to the following points for each type of occupied area:

(a) the property line for indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities and outdoor venues or recreation areas;

(b) the property line for outdoor venues or recreation areas, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly;

(c) the location of a building or structure used as a place of residency by a person, a family, or families; and

(d) the location of a commercial facility with five-thousand (5,000) or more square feet of building floor area that is operating and normally occupied during working hours.

Paragraphs (7) and (8) of Subsection C of Section 20.2.50.116 are part of EDF and CAA's Proximity Proposal. These provisions are necessary for determining what facilities are subject to the LDAR requirements under that provision. The Board adopts this section based on the testimony of EDF witness Dr. Tammy Thompson (EDF Exhibit TT, and Tr. Vol. 2717:11 – 2729:2, 2735:20

– 2741:11), and CAA witness Lee Ann Hill (CAA Exhibit 25, and Tr. Vol. 9, 2836:21 – 2847:1, 2849:20 – 2858:25). The Board finds based on substantial evidence that paragraphs (7) and (8) are more protective of public health and the environment. The Board rejects CEP's proposed insertion in (7) that a homeowner may request an evaluation as redundant, since this is already available; and rejects NMOGA's proposed post-hearing revisions in (7) and (8) as not clarifying.

(9) Injection well sites and temporarily abandoned well sites are not subject to the leak survey requirements of Paragraphs (3) through (6) of Subsection C of 20.2.50.116 NMAC.

Paragraph (9) of Subsection C of Section 20.2.50.116 expressly exempts injection well sites and temporarily abandoned well sites from the leak survey requirements of Paragraphs 3 through 6 of Subsection C of Section 20.2.50.116. This proposal is based on language jointly proposed by Oxy USA, EDF, CAA, CCP, and NAVA. The Board adopts this language because leak surveys are not anticipated to result in emissions reductions at these facilities. Tr. Vol. 2525:8-21.

(10) Prior to any monitoring event, the owner or operator shall date and time stamp the monitoring event.

Paragraph (10) of Subsection C of Section 20.2.50.116 requires the owner or operator to date and time stamp each monitoring event. The Board adopts this proposal for the reasons stated above regarding Subparagraph (b) of Paragraph (8) of Subsection A of Section 20.2.50.112. *See* NMED Rebuttal Exhibit 1, p. 23-24; Tr. Vol. 5, 1358:24 – 1359:14; 1368:21 – 1369:23; 1370:10 – 1371:5; 1428:2-25, 1427:4 – 1439:11.

D. Alternative equipment leak monitoring plans: An owner or operator may comply with the equipment leak requirements of Subsection C of 20.2.50.116 NMAC through an equally effective and enforceable alternative monitoring plan, which may include the use of alternative monitoring methods and technologies, as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to the department on an application form provided by the department. Within 90 days of receipt, the department shall issue a letter approving or denying the requested alternative monitoring plan. An owner or operator shall comply with the default monitoring requirements of Section 20.2.50.116 NMAC and may not operate under an alternative monitoring plan until it has been approved by the department.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements of Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved alternative monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department in writing of the intent to conduct monitoring under a pre-approved alternative monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting the first monitoring under that plan.

(b) the department may terminate the use of a pre-approved alternative monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of a pre-approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements of Subsection C of 20.2.50.116 NMAC within 15 days.

Subsection D of Section 20.2.50.116 provides owners and operators with the option to submit an alternative monitoring plan to comply with the monitoring requirements of Subsection C. Paragraph (1) gives the option for an owner or operator to propose an individual alternative monitoring plan for approval by the Department. The plan would have to be reviewed by a third-party prior to submission to ensure it is an equivalent, enforceable and appropriate monitory strategy. Paragraph (2) provides an option to use an alternative monitoring plan that has been preapproved by the Department. The Department will provide preapproved plans on its website and owners and operators can seek approval from the Department to use one of these preapproved plans. Use of an alternative monitoring plan must be approved by the Department and can be terminated by the Department if the owner/operator fails to comply with elements of the plan, or fails to correct or disclose a violation within 15 days of discovery. Oxy and CEP proposed language for a new Paragraph D(1)(a) as a clarification that alternative monitoring methods are allowed. The Board adopts NMED's proposal and CEP/Oxy's clarification because it provides flexibility to owners and operators and allows for the use of new technologies that are more efficient at discovering leaks. *See* NMED Exhibit 32, p. 84, NMED Exhibit Tr. Vol. 8, 2437:15 – 2439:16. *See* also TR-2605:18-23 (EDF's expert). At the request of NMED, rather than inserting a new Paragraph D(1)(a), the Board moves CEP/Oxy's clarification to Paragraph D for clarity and to keep Paragraph (1) consistent, such revision being agreed to by CEP/Oxy.

In addition to being more practical, alternative monitoring methods can also be more effective. Mr. Holderman noted that "Oxy USA has been piloting sensor-based technology to electronically capture gas emissions, audio data and visual data from locations as an alternative compliance method to AVO inspections. This method has the potential to be a more cost effective and accurate form of data capture than traditional AVOs which can enable greater emissions reductions. Alternative technologies have potential to result in more rapid identification and response than AVO inspections." TR-2527:5-14. In turn, more rapid identification and response capabilities allow operators to effectively reduce emissions.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component not otherwise repaired at the time of discovery until the component has been repaired;

(2) leaks shall be repaired as soon as practicable but no later than 30 days from discovery;

(3) the equipment must be re-monitored no later than 15 days after the repair of the leak to demonstrate that it has been repaired;

(4) if the leak cannot be repaired within 30 days of discovery without a process unit shutdown, the leak may be designated "Repair delayed," the date of the next scheduled process unit shutdown must be identified, and the leak must be repaired before the end of the scheduled process unit shutdown or within 2 years, whichever is earlier; and

(5) if the leak cannot be repaired within 30 days of discovery due to shortage of parts, the leak may be designated "Repair delayed," and must be repaired within 15 days of resolution of such shortage.

Subsection E of Section 20.2.50.116 sets forth repair requirements for leaks detected under this Section. When a leak is detected, the component must be visibly tagged until repaired and the leak must be repaired as soon as practicable but no later than 30 days from discovery. Equipment must be re-monitored no later than 15 days after discovery of a leak to demonstrate that the leak has been repaired. In agreement with NMOGA, NMED proposed revisions to Paragraph (4) of Subsection E to ensure that repairs will occur promptly while protecting against unexpected shutdowns. This provision specifies that, for leaks that cannot be repaired in the required timeframes above without a process shutdown, the leak may be designated as "Repair Delayed" and must be repaired before the end of the next scheduled process unit shutdown. For leaks that cannot be repaired in the required timeframes above due to a shortage of parts, the leak may be designated as "Repair Delayed" and must be repaired within 15 days of resolution of the shortage. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 83, NMED Rebuttal Exhibit 1, p. 62, and Tr. Vol 8, 2439:17 – 2440:13.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM 21, OGI, or alternative equipment leak monitoring inspections conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location (latitude and longitude);

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) monitoring method (e.g. AVO, RM 21, OGI, approved alternative method);

(d) name of the person(s) performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible tag was placed on the leak.

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of "repair delayed" the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery. If a delay is due to a parts shortage, a record documenting the attempt to order the parts and the unavailability due to a shortage is required;

(ii) the date of next scheduled process unit shutdown by which the repair will be completed; and

(iii) name of the person(s) who determined that the repair could not be implemented without a process unit shutdown.

(d) date of successful leak repair;

(e) date the leak was monitored after repair and the results of the monitoring; and

(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection F of Section 20.2.50.116 sets forth recordkeeping requirements for the leak monitoring and repairs required under this Section. Owners or operators must keep records of the following for all AVO, EPA Method 21, OGI, or alternative equipment leak monitoring inspections conducted pursuant to Section 20.2.50.116: facility location; date of inspection; monitoring method; name of the personnel performing the inspection; description of any leak requiring repair or a note that no leak was found; and whether a visible flag was placed on the leak or not. The owner or operator is required to record any leak detected, the date of detection, and the date of attempted repair. For leaks designated "repair delayed," the owner or operator must record the reason for delay for leaks not repaired within the allowed time frame, and an authorized representative's signature who determined the leak could not be implemented without process unit shutdown. The owner or operator must also record information regarding repair and follow-up monitoring. For a leak detected using OGI, the owner or operator must keep records as specified in EPA regulations at 40 C.F.R. Section 60.18(i)(1)-(3). Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 84-86.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

Subsection G of Section 20.2.50.116 sets forth reporting requirements for the leak monitoring and repairs required under this Section. Owners and operators are required to certify the use of an alternative equipment leak monitoring plan under Subsection D to the Department annually. Owners and operators must also comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 84-86.

Estimated Emissions Reductions Resulting from Section 20.2.50.116

ERG estimated total emission reductions of 4,654 tons per year of VOC for non-wellhead facilities and 14,896 tons per year of VOC for well site facilities, as detailed in NMED Exhibit 32, pp. 86-88, and NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet.

Estimated Costs of Section 20.2.50.116

The costs of implementing an LDAR program to reduce fugitive equipment leak emissions are those associated with labor required to conduct inspections and repair leaking components. ERG estimated the costs required to implement a new LDAR program under the proposed rule for well sites based on estimates for well sites from the EPA CTG (NMED Exhibit 34) and from the cost analysis for the 2014 amendments to Colorado Reg. 7. *See* NMED Exhibit 71 – Colorado Dept. of Public Health and Environment, *Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6 and 7 (5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)*, (February 11, 2014) ("2014 Colorado Regulatory Analysis"). NMED Exhibit 32, p. 88. The total annualized costs of implementing the LDAR requirements in Part 50 are estimated to be $2,847,945 for non-wellhead facilities, and $52,220,185 for well site facilities. A detailed explanation of how ERG estimated these costs is provided on pages 88-90 of NMED Exhibit 32. Given the emissions reductions expected as a result of the proposed rule, ERG estimated the cost effectiveness of reducing emissions from non-wellhead facilities at $5,100 per ton of VOC, and $3,506 per ton of VOC for well site facilities. A detailed explanation for *See id.* at 88-90.

NMOGA provided extensive comments regarding NMED's cost effectiveness analyses that were used to support the proposed emission thresholds and inspection frequencies in Section 20.2.50.116. NMOGA argued that the model plants included in the 2016 CTG were out of date and were not representative of the well sites in the San Juan and Permian Basins. NMOGA further claimed that model plants based on information in the GHGRP for the Permian and San Juan Basins better reflect well production facilities in New Mexico and should be used instead of the model plants in the 2016 CTG, and these would lead to lower emission reductions compared to those in the 2016 CTG. NMED could not evaluate the validity or representativeness of the alternative model plants mentioned by NMOGA, because NMOGA did not document in its testimony or exhibits the actual model plants they created and on which they estimated new emission reductions and cost effectiveness numbers. NMED Rebuttal Exhibit 1, pp. 62-63. The

Board finds that NMED properly relied on the model plants included in the 2016 CTG as the basis for its cost effectiveness analysis for this Section.

NMOGA also argued that the costs in the 2016 CTG did not account for additional cost elements that were discussed in comments submitted to the EPA on the draft CTG by the American Petroleum Institute (API). NMOGA argues that NMED should use the revised costs reflected in the API comments on the draft CTG. EPA, in its "Responses to Public Comments on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, October 2016," fully responded to the API comments mentioned in the NMOGA testimony and adjusted the cost estimates in the 2016 CTG as appropriate. *See* NMED Exhibit 34, pp. 191-196. The Board finds that it is beyond the scope of this rulemaking to reassess the EPA's response to these particular API comments on the 2016 CTG in the absence of any additional information from API or NMOGA relative to those original comments and EPA's response. NMED Rebuttal Exhibit 1, p. 63.

The Board finds that NMED's estimated costs associated with Section 20.2.50.116 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

Description of Equipment or Process

Liquids unloading is used to remove accumulated fluids in the wellbore of a natural gas production well. Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells, and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production declines, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the gas velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow gas production to overcome the surface equipment and flow out of the wellbore. While pressure is a factor, it is generally a lack of velocity that causes liquids to accumulate in the wellbore (i.e., to "load" or "load up"). New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and velocity declines and eventually a point is reached where liquids loading begins to be an issue. The time at which liquids loading occurs is dependent on the reservoir characteristics, and varies from well to well. A full description of the liquids unloading process and related issues is provided in NMED Exhibit 32, pp. 91-93

Control Options

VOC emissions from liquids unloading operations occur when the well is vented to the atmosphere to unload fluids or when the liquids are unloaded through atmospheric tanks and the gas mixed with the liquid is vented to the atmosphere. To reduce emissions and waste of gas during manual (i.e., non-automated) liquids unloading activities, operators can monitor manual liquids unloading events onsite within close proximity to the well or via remote telemetry to ensure that the well returns to normal production operation as soon as possible. NMED Exhibit 32, p. 93.

Rule Language

The proposed operational requirements and best management practices for limiting VOC emissions during natural gas well liquids unloading events are based on requirements in Colorado Reg. 7, Pennsylvania GP-5 and GP-5A, and the Wyoming Permitting Guidance, as detailed in NMED Exhibit 32, pp. 95-96.

CEP supported the Department's proposal in Section 117; *see* CEP's SOR 314-324.

A. Applicability: Liquid unloading operations resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Liquid

unloading operations that do not result in the venting of any natural gas are not subject to this Part. Owners and operators of a natural gas well subject to this Part must comply with the standards set forth in Paragraph (1) of Subsection B of 20.2.50.117 NMAC within two years of the effective date of this Part.

The requirements of Section 20.2.50.117 apply to liquid unloading operations resulting in the venting of natural gas at natural gas wells. Owners and operators of natural gas wells that are subject to this section have two years from the effective date of Part 50 to comply with the provisions of Paragraph (1) of Subsection B. The Department made a number of revisions to this Subsection based on comments from IPANM and NMOGA, as detailed in NMED Rebuttal Exhibit 1, pp. 68-69.

NMOGA and IPANM proposed to change the term "liquid unloading" to "manual liquid unloading" in Subsection A and throughout the rule where the term "liquid unloading" is cited. The Board rejects this proposal because it would restrict the type of unloading events covered under this Section. NMED intended to regulate both manual and automated liquid unloading events that result in venting of natural gas. NMED Rebuttal Exhibit 1, p. 68.

IPANM proposed to add language that this Section only applies in areas of the state specified in Section 20.2.50.2. The Board rejects this as unnecessary and redundant because Section 20.2.50.2 already expressly provides that all the requirements in Part 50 are only applicable to sources in the specified areas of the State. NMED Rebuttal Exhibit 1, p. 69.

B. Emission standards:

(1) The owner or operator of a natural gas well shall implement at least one of the following best management practices during the life of the well to avoid the need for venting of natural gas associated with liquid unloading:

(a) use of a plunger lift;
(b) use of artificial lift;
(c) use of a control device;
(d) use of an automated control system; or
(e) other practices if approved by the department.

(2) The owner or operator of a natural gas well shall implement the following best management practices during venting associated with liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown or venting to atmosphere;

(b) monitor manual venting associated with liquid unloading in close proximity to the well or via remote telemetry; and

(c) close vents to the atmosphere and return the well to normal production operation as soon as practicable.

Subsection B of Section 20.2.50.117 requires owners and operators of natural gas wells to implement at least one of several specified best management practices to avoid the need for venting of natural gas associated with liquid unloading. This Subsection also requires the use of certain best management practices to minimize emissions during venting associated with liquid unloading. These provisions are based on similar requirements in Colorado, Pennsylvania, and Wyoming. The Department made numerous revisions to its original proposal based on comments from NMOGA and IPANM, as detailed in NMED Rebuttal Exhibit 1, pp. 69-70.

The methods proposed by the Department are a selection of the technically feasible methods identified in the MAP Technical Report (NMED Exhibit 10), NMOGA's Methane Mitigation Roadmap (NMED Rebuttal Ex. 7), and EPA's Oil and Natural Gas Sector Liquids Unloading Processes (NMED Rebuttal Ex. 8). NMED proposed revisions to this Subsection to provide a suite of available options to forestall the need for venting, as discussed in the three technical documents mentioned above, and control emissions during venting (blowdown) events. Owners and operators are given flexibility to choose an appropriate method for any given source that is subject to these provisions.

The Board adopts NMED's proposal for the reasons stated in NMED Exhibit 32 pp. 93-96 and NMED Rebuttal Exhibit 1, pp. 69-70; and replaces the word "control" with the word "practices" in B(1)(e) to provide more opportunity for innovation, as suggested by IPANM.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during venting associated with liquid unloading:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the storage vessel, tank battery, or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted during a venting event associated with a liquid unloading event.

(3) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.117 sets forth monitoring requirements for liquid unloading events, including monitoring well-head parameters and performing VOC volume and mass calculations during an unloading event. Owners and operators must also comply with the general monitoring requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32 pp. 93-96. NMED's proposed language provides flexibility regarding this requirement and owners and operators can estimate this flow rate. NMED provided guidance in the rule when the flow rate of vented gas cannot be monitored directly by using the maximum potential flow rate in the emission calculation. NMED Rebuttal Exhibit 1, p. 71.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date of the unloading event;

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the estimated flow rate in the emission calculation);

(e) duration of venting to the storage vessel, tank battery, or atmosphere;

(f) a description of the best management practices used to minimize venting of VOC emissions during the life of the well and before and during the liquid unloading; and

(g) a calculation of the VOC emissions vented during a liquid unloading event based on the duration, calculated volume, and composition of the produced gas.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.117 sets forth recordkeeping requirements for liquid unloading events. Owners and operators are required to maintain records of well location and ID number, liquid unloading dates, wellhead pressure, vented gas flow rate (to the extend feasible), duration of venting event, VOC management practice used before and during liquid unloading, device used to control VOC emissions during unloading, and calculation of VOC emissions vented during unloading. The VOC calculation is based on the duration, volume, and mass of the VOC. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32 pp. 93-96, and NMED Rebuttal Exhibit 1, p. 71.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.117 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.117 specifies that owners and operators must comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 94-96.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.117

As described in NMED's rebuttal testimony, ERG estimated that installation of plunger lifts on wells requiring liquids unloading that currently do not employ this technology would result in reductions of 4,272 tpy of VOC, or 36% of the baseline VOC emissions. No estimates were available to quantify the reductions expected from implementation of the proposed best management practices requirements under Part 50. NMED Rebuttal Exhibit 1, pp. 96-97.

The ICF Economic Analysis estimated that costs associated with installation of a plunger lift include capital costs of $20,000 and operating costs of $2,400. In a 2011 report, EPA estimated that the payback period for installing a plunger lift could be from 1 to 8 years, depending on the value of natural gas and well-specific parameters. EPA has further found that the advantages of a plunger lift, in addition to reduced VOC and methane emissions, include increased productivity and reduced well maintenance, such as treatments to remove scale and paraffin. NMED Exhibit 32, pp. 97-98.

The Board finds that NMED's estimated costs associated with Section 20.2.50.117 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

With the edit in 117.B(1)(e), the Board adopts NMED's proposal, as supported by CEP, and rejects IPANM and NMOGA's proposed revisions for the reasons given by NMED and CEP. EDF witness Tom Alexander testified the best management practices proposed in NMED's proposed Section 117 are all effective, cost effective, and technologically practicable methods to reduce emissions during liquids unloading. EDF Ex. WW at 2. In his experience, these are not only standard industry practices, but have been in the production engineering toolkit for decades. EDF Ex. WW at 2-3; 10 Tr. 3216:25-3218:6, -3220:15-3221:9. In Mr. Alexander's experience, artificial lift is a preferred method of keeping a well unloaded and producing efficiently. And in the end, a well that is produced properly will have a higher estimated ultimate recovery. 10 Tr. 3231:5-3232:1.

IPANM's revisions would weaken the proposed rule and will result in less emissions reductions. EDF Ex. WW, p. 4. IPANM proposes to limit the applicability of the liquids unloading provision to manual unloading events only. This would significantly narrow the applicability of the rule by completely ignoring emissions from artificial lift technologies used during non-manual unloading activities. While resulting in far fewer emissions than manual unloading, the use of artificial lift technologies to unload a well nevertheless results in some emissions. EDF Ex. WW at 4. Mr. Alexander strongly disagreed with IPANM's proposal to strike the use of a control device as a listed method to reduce emissions during unloading events for two reasons. EDF Ex. WW at 4. First, the methods to reduce emissions during unloading listed by NMED are all feasible and economic. 10 Tr. 3220:21-3221:9; EDF Ex. WW at 4. Second, because the rule only requires "at least one of the following best management practices," the operator is free to select the method best suited to the particular well. 10 Tr. 3251:11-3252:13. Finally, Mr. Alexander strongly disagreed with the revision to apply only to manual unloading since artificial lift methods, such as plunger lifts, can result in some minimal emissions. EDF Ex. WW at 5.

20.2.50.118 GLYCOL DEHYDRATORS:

Description of Equipment or Process

A glycol dehydrator is a liquid desiccant system for the removal of water from natural gas and natural gas liquids. Triethylene glycol is the most commonly used desiccant in these systems. Failure to remove water results in formation of crystalline hydrates at the high pressures used to transport the gas. Hydrates can block pipelines, jam valves, and can generally wreak havoc on pipeline equipment and instrumentation. In the glycol dehydrator, the triethylene glycol absorbs water and VOCs from the gas. The triethylene glycol is then regenerated by heating it to release the absorbed compounds. The reboiler from a large glycol dehydrator can discharge more than one hundred tons per year of VOCs, including benzene, toluene, ethylbenzene and xylene (collectively, "BTEX"). For a full description of glycol dehydrators, *see* NMED Exhibit 32, pp. 98-100.

Control Options for Glycol Dehydrators

There are a number of options available to owners and operators of glycol dehydrators for controlling emissions. Still vent and flash tank emissions can be routed at all times to the reboiler firebox (for use as fuel), a condenser, combustion control device, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or a natural gas gathering pipeline. *See* testimony regarding control devices (Section 20.2.50.115) for a discussion of VRUs. A combustion control device is either a flare or an enclosed combustor. A condenser uses water, air, or another coolant to lower the temperature of the vent gases and cause the vapors to condense from gas to liquid phase where they can be collected. Costs were estimated for condensers and combustion control devices because existing cost estimates are readily available and are more universally applicable. Costs for other control options are more site-specific and standardized cost estimating methods are not readily available. NMED Exhibit 32, pp. 100-101.

Rule Language

The proposed requirements in Section 20.2.50.118 are based on similar requirements for dehydrators adopted by Colorado and Pennsylvania, as well as federal regulations. A full discussion of the basis for these requirements is in NMED Ex. 32, pp. 102-103.

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

Section 20.2.50.118 applies to glycol dehydrators with a PTE equal to or greater than two tons per year of VOC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. The Board adopts this proposal for the reasons stated in NMED Ex. 32, pp. 98, 101-104.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) no later than two years after the effective date of this Part. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) the still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the VOC emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that reinjects the vapor into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the controlled equipment is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent, which shall supersede any inconsistent requirements in 20.2.50.115 NMAC. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications; and

(c) the still vent and flash tank emissions shall not be vented directly to the atmosphere during normal operation.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy of VOC.

Subsection B of Section 20.2.50.118 sets forth emission standards for glycol dehydrators. Owners and operators of existing dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank by at least 95% no later than two years after the effective date of the rule. Owners and operators of new glycol dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank by at least 95% upon startup. For both new and existing dehydrators, the combustion device (if used) must meet a minimum 98% destruction efficiency. Still vent and flash tank emissions must be routed to a control device, a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline. If a VRU is used, the VRU must be operational at least 95% of the time, resulting in a minimum combined capture and control efficiency of 95%. The requirements of Section 20.2.50.118 cease to apply when the actual annual VOC emissions from a new or existing glycol dehydrator are less than 2 tpy VOC. The Department made a number of revisions to this Subsection based on comments from IPANM and NMOGA, as detailed in NMED Rebuttal Ex. 1, pp. 72-73.

The Board adopts the Department's proposal, as amended in B(3)(b) by NMOGA, for the reasons stated in NMED Ex. 32, pp. 101-105; and NMOGA Exhibit 46:15:39-46 – 16:1-16. *See also* Bisbey-Kuehn Testimony, Tr. 7:2322:2-6; and Textor rebuttal testimony, NMOGA Exhibit 46:14:16-26. The amended language clarifies that the redundant VRU requirement does not supersede the allowed 5% downtime.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.118 sets forth monitoring requirements for glycol dehydrators. Owners and operators are required to conduct an annual extended gas analysis to determine the composition of the gas being processed by the dehydrator and must to use this gas analysis to calculate the uncontrolled and controlled emissions from the dehydrator. This calculation will demonstrate whether the 95% emission reduction requirement is met. Owners and operators are required to inspect dehydrators and control devices or processes semi-annually to ensure integrity of the equipment and that the equipment is being operated as initially designed and in accordance with manufacturers specifications. Monitoring events must be date and time stamped. Owners and operators complying with Section 20.2.50.118 through the use of a control device must comply with the monitoring requirements in Section 20.2.50.115. Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 102-105.

Estimated emissions from a source should be based on the most accurate information available. A representative gas analysis may be appropriate for a well that has yet to be constructed, but the requirement in this Section is for an annual calculation for all dehydrators in operation whether they qualify as a “new” or “existing” source under this rule. Calculations based on the composition of the actual gas being processed by the subject source are by definition more accurate, and the Department requires extended gas analyses for its permits. NMED Rebuttal Exhibit 1, p. 73.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) unique identification number and dehydrator location (latitude and longitude);

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and unique identification number of the control device or process the emissions are being routed;

(f) time and date stamp, including GPS of the location, of any monitoring;

(g) results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(h) a copy of the glycol dehydrator manufacturer specifications.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.118 sets forth recordkeeping requirements for glycol dehydrators. Owners and operators are required to keep records of equipment throughput data, emissions calculations and supporting documentation, inspection results, and manufacturer information. These records must be maintained onsite and submitted to the Department upon request. The recordkeeping requirements of Section 20.2.50.115 apply where a control device is being used to comply with the requirements of Section 20.2.50.118. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 102-105.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.118 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.118 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 102-105.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.118

ERG estimated that the controls required under Section 20.2.50.118 would reduce emissions by 1,865 tpy, leading to a 46.2% overall reduction in VOC emissions from dehydrators. The emission reduction analysis is detailed in NMED Exhibit 32, pp. 103-104, and NMED Exhibit 77 – Dehydrators Reductions and Costs Spreadsheet.

ERG estimated the annualized cost for installing and operating a condenser to be $21,560 and the annualized cost for installing and operating a combustor to be $10,583. The total annualized costs of adding condensers to the 199 dehydrator units was estimated at approximately $4,300,000 per year, while the total annualized costs of adding combustors to the 199 dehydrator units was estimated at approximately $2,100,000 per year. Costs for both condensers and combustion controls were presented for information purposes, although for each dehydrator the owner of operator would install either a condenser or a combustor, not both. A full explanation of ERG's cost analysis for glycol dehydrators is presented in NMED Exhibit 32, pp. 104-105. The Board finds that NMED's estimated costs associated with Section 20.2.50.118 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.119 HEATERS:

Description of Equipment or Process

Natural gas-fired heaters are used throughout the oil and gas production and processing sectors to prevent equipment from freezing and being blocked by the formation of ice or hydrates; to improve the separation of well products into oil, water, and natural gas; and in certain types of process equipment, such as glycol dehydrators. A full description of heaters and their use in oil and gas operations is provided in NMED Ex. 32, pp. 105-106.

Control Options

NO_X emissions from heaters may be controlled through combustion modifications that reduce the formation of NO_X; through the use of add-on controls to control NO_x in the exhaust stack; or through a combination of combustion modifications and add-on controls. Combustion modifications include low-NO_X burners (LNBs), ultra-low NO_X burners (ULNBs), and flue gas recirculation (FGR). Add-on controls include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). In addition to combustion modifications and add-on controls, many regulatory programs require periodic equipment tune-ups and good combustion practices to keep heaters operating at maximum efficiency in order to reduce emissions. Good combustion practices are also important in controlling CO and VOC emissions. NMED Ex. 32, p. 107.

Rule Language

The proposed NO_X and CO limits are based on limits adopted by the State of Pennsylvania and EPA for natural gas fired combustion units. The NO_X limits are the same as those in the Pennsylvania GP-5 requirements for natural gas-fired combustion units. *See* NMED Exhibit 37 at Section L, p. 24. The CO limits are the same as those in the federal regulations at 40 C.F.R. 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* ("NESHAP Subpart DDDDD"). *See* NMED Exhibit 80. CO is commonly regulated as a surrogate for VOC or organic hazardous air pollutants (HAPs) because CO is a good indicator of incomplete combustion and VOC and HAP are products of incomplete combustion. EPA used CO limits instead of hazardous air pollutant limits in NESHAP Subpart DDDDD because it "concluded that CO, which is less expensive to test for and monitor, is appropriate for use as a surrogate for non-dioxin organic HAP." *Id.*, at p. 52210. NMED Exhibit 32, p. 108.

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

Section 20.2.50.119 applies to natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. In response to comments from IPANM proposing to raise the applicability threshold for heaters to 50 MMBtu/hr, NMED agreed to revise its original applicability threshold for heaters NMED presented costs associated with the requirements for heaters in Part 50 in the ERG – Heaters Reductions and Costs NO2 Spreadsheet at NMED Exhibit 82.

These costs were taken from the EPA 1993 ACT document at NMED Exhibit 53, and were based on a 17 MMBtu/hr heater, which is the smallest heater size for which cost data is available. A review of the available heater data in the costing spreadsheet indicates only 2 of the 82 heaters that would be subject to the rule are 10 MMBtu/hr heaters. The EPA 1993 ACT document indicates the cost effectiveness for a 17 MMBtu/hr heater operating at 90% capacity is $4,742/ton NOx, which NMED considers reasonable. A 10 MMBtu/hr heater would have lower emissions than a 17 MMBtu/hr heater, which would result in a higher cost effectiveness using the same annualized costs as a 17 MMBtu/hr heater. Based on the increased costs for the smallest heaters subject to the rule, NMED proposed to revise the applicability threshold to 20 MMBtu/hr, which is larger than the heater size used in the cost calculations and supports more cost-effective reductions. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 105-110, and NMED Rebuttal Exhibit 1, pp. 75-76.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	400
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	400

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than three years after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

Subsection B of Section 20.2.50.119 sets forth emissions standards for natural gas-fired heaters. Existing and new natural gas-fired heaters are limited to 30 ppmvd NO_X at 3% oxygen, and 400 ppmvd CO at 3% oxygen. Existing heaters must comply with these standards no later than three years after the effective date of Part 50, while new heaters must comply upon startup. NMED revised the emissions limits for CO from 300 ppmvd to 400 ppmvd, and raised the timeline for compliance for existing heaters from one year after the effective date to three years after the effective date based on comments from NMOGA. The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 107-110, and NMED Rebuttal Ex. 1, pp. 73-75.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly, if present;

(iv) optimizing total emissions of CO consistent with the NO_x requirement and manufacturer specifications, and good combustion practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_X or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load in a prior test plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(5) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.119 sets forth monitoring requirements for natural gas-fired heaters. Owners and operators are required to conduct emission testing for NO_X and CO within 180 days of the applicable compliance date, and at least every two years thereafter. The equipment must be inspected, maintained, and repaired in accordance with the manufacturer's specifications at least once every two years after the applicable compliance date. An owner or operator may deviate from the specified periodic testing procedures by submitting a written request to use an alternative procedure to the Department at least 60 days prior to performing the periodic testing, but must receive written approval from NMED prior to conducting periodic testing using an alternative procedure. The owner or operator must comply with the general monitoring requirements in Section 20.2.50.112.

The Board adopts this proposal for the reasons stated in NMED Ex. 32, pp. 107-110, and NMED Rebuttal Ex. 1, pp. 73-75. The rule allows for testing at highest achievable load ***or*** within ten percent of one hundred percent peak load. Heater tests already have the option to verify emissions only at the highest achievable capacity. NMED Rebuttal Exhibit 1, p. 74.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) unique identification number and location (latitude and longitude) of the heater;

(2) summary of the complete test report and the results of periodic testing;

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date and time stamp, including GPS of the location, of the inspection, testing, maintenance, or repair conducted;

(b) name of the person(s) conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.119 sets forth recordkeeping requirements for natural gas-fired heaters. Owners and operators are required to maintain records of the following information: location of the heater; summary of the complete test report and results of periodic testing; and inspections, testing, maintenance, and repairs. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 107-110.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.119 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.119 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 107-110.

Estimated Costs and Emission Reductions Resulting from Section 20.2.50.119

ERG estimated total reductions of 216 tons per year of NO_X for an overall reduction of 16% from the baseline of 1,355 tpy NOx. ERG estimated a total annualized cost to meet the proposed emission limits of approximately $684,341 at a cost effectiveness of $3,162 per ton of NO_X reduced. A full description of ERG's costs and emission reductions analyses for Section 20.2.50.119 is provided in NMED Exhibit 32, pp. 108-110 and NMED Exhibit 82 – Heaters Reductions and Costs NO2 Spreadsheet.

The Board finds that NMED's estimated costs associated with Section 20.2.50.119 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

Description of Equipment or Process

Hydrocarbon liquid transfers involve moving hydrocarbon liquid from a transfer vessel to a storage tank, or from a storage tank to a transfer vessel. There are three primary methods of vessel loading: splash loading, submerged fill pipe (a pipe inserted into a tank to facilitate loading) and bottom loading. For splash loading, the fill pipe is lowered only part way into the vessel, and the resultant splashing generates VOC emissions. In submerged fill pipe loading, the fill pipe will extend close to the bottom of the vessel. In bottom loading, a permanent fill pipe is connected at the bottom of the vessel. Both submerged fill pipe loading and bottom loading reduce the generation of VOC emissions. During the transfer of hydrocarbon liquids from one vessel to another, the remaining VOC-containing vapor from the previous contents of the vessel will also be vented as the vessel is filled. NMED Exhibit 32, p. 110.

Control Options

The options typically used to reduce VOC emissions from hydrocarbon liquid transfers are similar those for storage tanks, and include: (1) routing emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – "route to a process" (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite; and/or (2) routing emissions from the storage vessel to a combustion device. In practice, many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks. NMED Exhibit 32, p. 111.

In addition to these control options, emissions from hydrocarbon liquid transfers are also commonly controlled using vapor balancing service, whereby the vapors in the tanker truck or railcar are routed back into the storage vessel as the liquids in the storage vessel are emptied into the receiving vessel (the truck or railcar). Vapor balancing requires a pipe or hose connected between the storage vessel and the receiving vessel prior to transfer. Bottom loading and submerged filling are additional best management practices used to reduce emissions from hydrocarbon liquid transfers. *Id.*

Rule Language

The proposed control and operational requirements are based on requirements in Colorado's Reg. 7, Section II.C.5 (NMED Exhibit 39); Pennsylvania GP-5 and GP-5A (NMED Exhibits 37 and 38); Utah's Rule R307-504 – Oil and Gas Industry: Tank Truck Loading, (NMED

Exhibit 83); and Wyoming's presumptive BACT for oil and gas truck loading operations, found in the Wyoming Permitting Guidance (NMED Exhibit 40). As described in NMED Exhibit 32, these other states require various best management practices and/or the use of control devices such as enclosed combustors to control emissions from hydrocarbon liquid transfers. NMED Exhibit 32, pp. 113-115.

A. Applicability: Hydrocarbon liquid transfers located at existing well sites, standalone tank batteries, gathering and boosting stations with one or more controlled storage vessels, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC within two years of the effective date of this Part. Hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels are subject to the requirements of 20.2.50.120 NMAC on the schedule specified in Paragraph 1 of Subsection B of 20.2.50.123 NMAC. Hydrocarbon liquid transfers located at new well sites, standalone tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC upon startup. The following facilities and operations are not subject to the requirements of this Section:

(1) Any facility connected to an oil sales pipeline that is routinely used for hydrocarbon liquid transfers;

(2) Well sites, standalone tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations not connected to an oil sales pipeline that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year; and

(3) Transfers of hydrocarbon liquid from a transfer vessel to a storage vessel subject to the emission standards in 20.2.50.123 NMAC.

Section 20.2.50.120 is applicable to hydrocarbon liquid transfer operations (or hydrocarbon liquid loading) at well sites, standalone tank batteries, gathering and boosting stations with one or more controlled storage vessels, natural gas processing plants, and transmission compressor stations. Transfer operations at existing facilities have two years from the effective date to comply with this Section, and transfers at new facilities must comply upon startup. The Department included the extended timeline for existing facilities based on comments from Oxy USA and NMOGA. NMED Exhibit 32, pp. 110-116; NMED Rebuttal Exhibit 1, p. 76.

NMED also proposed to include a revised schedule for a subset of hydrocarbon liquid transfer operations, namely, transfer operations at existing gathering and boosting stations without any controlled storage vessels, based on concerns raised by NMOGA regarding how the requirements of Section 20.2.50.120 interact with the requirements for storage vessels in 20.2.50.123. Paragraphs (1), (2), and (3) provide an offramp from the requirements of Section 120 for facilities that are connected to an oil pipeline routinely used for hydrocarbon liquid transfers, for facilities that load out hydrocarbon liquids to trucks fewer than 13 times per year, and for transfers from a transfer vessel to a storage vessel subject to the emissions standards of 20.2.50.123. NMED added these paragraphs in response to comments by NMOGA and CDG. NMED Rebuttal Exhibit 1, p. 76.

The Board adopts the Department's proposal, supported in part by IPANM (as to the 13 hydrocarbon liquid load out events to trucks per year limit) and largely by NMOGA (as to the 13 events limit and other changes making the rule more technically practicable and economically reasonable), for the reasons stated above and in NMED Exhibit 32, pp. 110-116, and NMED Rebuttal Exhibit 1, p. 76. NMED proposed revisions to exclude facilities that are connected to an oil sales pipeline, and at facilities that load out hydrocarbon liquids fewer than 13 times per calendar year. Those two provisions are sufficient to address facilities with a small number of loadout events. *See* NMED Rebuttal Exhibit 1A, p. 1-2. *See also* NMOGA Exhibit A1, 26:1-46 – 27:1-12; NMOGA Exhibit A1, 27:15-26; and NMOGA Exhibit A1, 28:37-46.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-five percent, when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker railcar for transport. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) An owner, operator, or personnel conducting the hydrocarbon liquid transfer using vapor balance shall:

(a) transfer the vapor displaced from the transfer truck or railcar being loaded back to the storage vessel being emptied via a pipe or hose connected before the start of the transfer operation. If multiple storage vessels are manifolded together in a tank battery, the vapor may be routed back to any storage vessel in the tank battery;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) inspect connector pipes, hoses, couplers, valves, and pressure relief devices for leaks;

(d) check the hydrocarbon liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Connector pipes and couplers shall be inspected and maintained to ensure there are no liquid leaks.

(4) Connections of hoses and pipes used during hydrocarbon liquid transfers shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(5) Liquid leaks that occur shall be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

Subsection B of 20.2.50.120 sets forth emission standards for hydrocarbon liquid transfer operations. The Department incorporated numerous revisions to its proposal in this Subsection based on comments from NMOGA; *see* NMED Rebuttal Exhibit 1, p. 77.

Paragraph (1) requires owners or operators to control VOC emissions by at least 95% via vapor balance, vapor recovery, or a control device. If using a combustion control device, it must have a minimum design combustion efficiency of 98%. Paragraph (2) specifies the requirements that owners or operators using vapor balance must comply with, including the following: displaced vapor must be loaded back to the vessel being emptied via pipe or hose connected before the start of the transfer operation; transfer cannot begin until the vapor collection and return systems are properly connected; connector pipes, hoses, couplers, valves and pressure relief devices must be inspected for leaks; hydrocarbon liquid and vapor line connections must be checked for proper connection prior to commencing the transfer operation; and transfer equipment must be operated at a pressure less than the pressure relief valve setting of the receiving vehicle or vessel.

Paragraphs (3) through (5) specify that, for all transfer operations, connector pipes and couplers must be inspected for liquid leaks, hose and pipe connections must be supported on drip trays to collect any leaks, and the materials collected must be returned to the process or properly disposed of. Liquid leaks must be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected must be returned to the process or properly disposed of. Paragraph (6) provides that owners and operators using a control device to comply with the emission standards of Section 20.2.50.120 must comply with the control device requirements in Section 20.2.50.115.

The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 110-116, and NMED Rebuttal Exhibit 1, p. 77. The Board rejects NMOGA's proposed edit in B(3) as unsupported by evidence in the record.

C. Monitoring requirements:

(1) The owner, operator, or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations and semi-annually at unstaffed locations to ensure that hydrocarbon liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. At least once per calendar year, the inspection shall occur during a transfer operation. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation, or measures must be implemented to mitigate leaks until the necessary repairs are completed.

(2) The owner or operator of a hydrocarbon liquid transfer operation controlled by a control device must follow manufacturer specifications for the device.

(3) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(5) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.120 sets forth the monitoring requirements for hydrocarbon liquid transfer operations. The Department incorporated numerous revisions in this Section based on comments from NMOGA, *see* NMED Rebuttal Exhibit 1, p. 78.

Paragraph (1) requires owners, operators, or their designated representatives to visually inspect the transfer equipment for leaks monthly at staffed locations, and semi-annually at unstaffed locations. At least once per calendar year, the required inspection must occur during a transfer operation. If leaks are discovered, they must be repaired prior to the next transfer operation, or mitigated until necessary repairs are completed. Paragraph (2) requires operations that employ a control device to follow the manufacturer's specifications for the device. Paragraph (3) requires that an owner or operator using vapor balance, vapor recovery, or a control device to minimize VOC emissions must comply with the monitoring requirements contained in Section 20.2.50.115. Paragraph (4) requires monitoring events under Section 20.2.50.20 to be date and time stamped according to the requirements of Part 50. Paragraph (5) requires owners and operators to comply with the general monitoring requirements in Section 20.2.50.112.

The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 112-116, and NMED Rebuttal Exhibit 1, p. 78. The Board rejects Oxy's proposal to remove the requirement that at least one inspection per calendar year under Paragraph (1) be conducted during a transfer operation as less protective. Ms. Kuehn testified that an inspection during a transfer operation is important component of the inspection requirements in this Section. *See* NMED Exhibit 32, pp. 112-116; and NMED Rebuttal Ex. 1, p. 78; and Tr. Vol. 1962:1-8.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the following:

(a) the location of the facility;

(b) if using a control device, the type, make, and model of the control device;

(c) the date and time stamp, including GPS of the location, of any inspection;

(d) the name of the person(s) conducting the inspection;

(e) a description of any problem observed during the inspection; and

(f) the results of the inspection and a description of any repair or corrective action taken.

(2) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.120 sets forth recordkeeping requirements for hydrocarbon liquid transfer operations. Owners or operators conducting transfer operations must maintain records of the location of the facility; if using a control device, records of the type, make and model; date and time stamp, including GPS location, of any inspection; and other records relating to required inspections and repairs. Records must also be maintained of the annual total hydrocarbon liquid transferred and annual VOC emissions from each site. On an annual basis, the owner or operator is required to create a company-wide record summarizing the total annual hydrocarbon liquid transferred and the total annual calculated VOC emissions. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 112-116, and NMED Rebuttal Exhibit 1, pp. 78-79.

The record of the control device used is necessary to determine compliance with this Section. Otherwise, there is no record documenting the type of control utilized to meet the emissions standards of this Section. NMED agreed to change the language requiring a record of the location of the storage vessel to requiring a record of the location of the facility. NMED Rebuttal Exhibit 1, p. 78. NMED Exhibit 32 provided the data regarding liquid transfers, and the estimated emissions reductions and costs for the proposed requirements. The records required in Subsection D of 20.2.50.120 are necessary for determining compliance with the emission standards of this Section, and are consistent with requirements for these types of operations in other states. NMED Exhibit 32 at pp. 113-116; NMED rebuttal Exhibit 1, p. 79.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.120 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.120 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32 at p. 113-116.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.120

ERG estimated the total emissions reductions from Section 20.2.50.120 at 4,263 tpy of VOC for an overall reduction of 86.8%. The total annualized costs of installing controls at these facilities were estimated at $2,283,886, resulting in an overall cost effectiveness of $536/ton of VOC controlled. A full explanation of ERG's emission reductions and cost analyses is provided NMED Exhibit 32, p. 115 and NMED Exhibit 84 – Transfers Reductions and Costs Spreadsheet. The Board finds that NMED's estimated costs associated with Section 20.2.50.120 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.121 PIG LAUNCHING AND RECEIVING:

Description of Equipment or Process

Natural gas passing through gathering pipelines contains VOCs, as well as other impurities such as water and carbon dioxide. As this gas passes through the pipeline system, any change in temperature or pressure may result in development of natural gas condensates in a liquid phase in the pipeline. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of these pipelines, operators insert a device called a “pig” into the pipeline which is swept along the pipeline by the pressure of the existing gas flow. Condensate and any other solid or liquid materials that have formed in the pipeline are pushed along in front of the pig until it reaches a “receiver,” at which point the pig is isolated in an offshoot pipeline segment and any condensates and liquids are drained out of the pipeline. The pig is then reinserted and swept along the next segment of pipeline. Pigs may also be used to create physical separation between different fluids flowing through the pipeline, for cleaning the internal surfaces of the pipelines, inspection of the condition of pipeline walls, and recording information relating to pipelines (e.g., size, location). NMED Exhibit 32, pp. 116-17.

Emissions to the atmosphere may occur at both the pig launcher and receiver when the pipeline is opened to insert or extract the pig. Emissions from pigging operations depend on factors such as the launcher or receiver volume, pipeline pressure, the amount of liquid trapped in the pig receiver barrel prior to depressurization, frequency of pigging, and gas composition. *Id.* at 117.

Control Options

Emissions from pigging operations may be controlled through process modifications, through the use of add-on controls such as a flare, enclosed combustor or thermal oxidizer, or by using a VRU. EPA has identified several process modifications to minimize emissions from pigging operations. These are discussed in detail in NMED Exhibit 32, pp. 118-19, and NMED Exhibit 85 – MarkWest Consent Decree.

Rule Language

The proposed requirements for pigging operations are based on Pennsylvania GP-5 and GP-5A, and Ohio's General Permit 21.1 for Title V and non-Title V pigging operations ("Ohio General Permits"). NMED Exhibit 32, p. 120. NMOGA and Kinder Morgan proposed to remove Section 20.2.50.121 in its entirety, or alternatively to limit the applicability of the requirements to within a facility's property boundary.

The Department's proposal was based on similar requirements in Pennsylvania GP-5 and GP-5A, and Ohio's General Permits; *see* NMED Exhibit 32 at p. 119-120. Colorado also recently proposed regulations targeting emissions from pigging operations. NMED Rebuttal Exhibit 1, p. 79. Other states have found it worthwhile and appropriate to regulate these operations. NMED explained that it has data on at least 10 facilities with these operations, and that this rule would reduce VOC emissions by at least 24 tpy. NMED Exhibit 32, p. 120. NMED also testified that they know the universe of affected operations is larger than what the data shows, and therefore the emissions reductions will be greater than what the modeling shows. *See* NMED Exhibit 32, p. 121; NMED Rebuttal Exhibit 1, pp. 79-80. For these reasons, the Board finds that some level of regulation for pigging operations is warranted, and rejects industry's proposals to entirely remove this provision from Part 50. NMED did propose significant revisions to this Section to incorporate most of the changes proposed by the industry parties; *see* NMED Rebuttal Exhibit 1, pp. 79-80.

Generally the Board rejects NMOGA's argument that the adoption of Section 121 as to pig launching and receiving is unsupported by the record. In the absence of a federal counterpart, the Board finds that based on substantial evidence, the proposal at Section 121 is more protective of public health and the environment.

A. Applicability: Individual pipeline pig launcher and receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

Section 20.2.50.121 applies to pipeline pig launcher and receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership and control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. NMED made significant revisions to its original proposal based on comments from NMOGA, Kinder Morgan, and CDG, including proposing an applicability threshold of one tpy VOC, limiting applicability only to pig launching within the property boundary of the listed facilities under common ownership and control with those facilities. *See* NMED Rebuttal Exhibit 1, p. 80. The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 116, 119-123; and NMED Rebuttal Exhibit 1, p. 80.

B. Emission standards:

(1) Owners and operators of affected pipeline pig launcher and receiver operations shall capture and reduce VOC emissions from pigging operations by at least ninety-five percent within two years of the effective date of this Part. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) The owner or operator conducting an affected pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to minimize emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to minimize emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that minimizes emissions to the atmosphere to the extent practicable; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to an individual pipeline pig launching and receiving operation if the actual annual VOC emissions of the launcher or receiver operation are less than one tpy of VOC.

(4) An owner or operator complying with Paragraphs (1) or (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

Subsection B of 20.2.50.121 outlines the emissions standards for pig launcher and receiver operations. Owners and operators of affected pigging operations are required to capture and reduce VOC emissions by at least 95% within two years of the effective date of Part 50. In addition, owners and operators must employ a suite of best management practices and equipment modifications during pigging operations to minimize or prevent emissions. These emission standards cease to apply where actual annual VOC emissions from an individual pipeline pig launching and receiving operation are less than 1 tpy VOC. Owners and operators complying with the requirements of Section 20.2.50.121 through the use of a control device must comply with the requirements of 20.2.50.115. NMED agreed to numerous revisions to this Subsection based on comments from NMOGA and CDG, including reducing the capture and control efficiency from 98% to 95%, extending the compliance deadline to two years from the effective date of Part 50, and owners and operators to minimize emissions rather than prevent them.

In the absence of a federal counterpart, the Board finds that based on substantial evidence, this provision is more protective of public health and the environment.

The Board adopts the Department's proposal, with the amendment proposed by NMOGA and CDG to replace the word "prevent" with the word "minimize" in B(2)(b) for the reasons stated in NMED Exhibit 32, pp. 119-123; NMED Rebuttal Exhibit 1, pp. 80-81; NMOGA Exhibit 46: 10:7-27; and consistency with B(2)(a) and B(2)(c). The Board rejects NMOGA's proposed addition in B(4), regarding portable devices, because portable equipment is already addressed in Section 115, and because monitoring requirements are important.

C. Monitoring requirements:

(1) The owner or operator of an affected pig launching and receiving site shall inspect the equipment for leaks using AVO, RM 21, or OGI on either:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

(b) prior to the commencement and after the conclusion of the pig launching or receiving operation, if less frequent.

(2) The monitoring shall be performed using the methodologies outlined in Subsection (C) of 20.2.50.116 NMAC as applicable and at the frequency required in Paragraph (1) of Subsection (C) of 20.2.50.121 NMAC. The monitoring shall be performed when the pig trap is under pressure.

(3) An owner or operator complying with Paragraphs (1) or (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.121 sets forth monitoring requirement for affected pig launcher and receiver operations. Owners and operators must inspect equipment for leaks using the identified monitoring methods on a monthly basis of pigging operations occur monthly or more frequently, and before commencement and after conclusion of pigging operations if less frequent. Monitoring must be performed using the methodologies outlined in Subsection C of Section 20.2.50.116. Owners and operators complying with the emission standards in Section 20.2.50.121 through the use of a control device must comply with the monitoring requirements in 20.2.50.115.

Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112. NMED made several revisions to the requirements in this Subsection based on comments from NMOGA and Kinder Morgan including adding AVO as an option for monitoring; revising the monitoring frequency to match the frequency of operations; removing the requirement to monitor according to Section 20.2.50.112 and substituting monitoring according to Sections 20.2.50.116 and 20.2.50.121; removing the requirement to monitor the amount and type of liquid cleared; and other edits that clarify the intent of this Section. The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 119-23, and based on the support from Kinder Morgan and, in part, NMOGA, below.

Kinder Morgan notes that infrequent pigging in the transmission segment coupled with the low VOC content natural gas present in the transmission segment results in very low VOC emissions from transmission pigging operations. Rebuttal NOI, Ex. XVI at 1. Kinder Morgan presented data demonstrating that annual VOC emissions from certain of the company's compressor stations in 2020 and 2019 were less than 0.04 tpy per compressor station. *Id*. at 1; *see* also Id., Attachment BB. It would be unreasonable to require transmission compressor station operators to monitor pigging units monthly when they are pigging every 2 to 5 years. 20.2.50.121.C.(1)(b) NMAC addresses this concern by requiring monitoring prior to and after the conclusion of pigging operations, if pigging operations at a site occur less frequently than once per month.

NMOGA notes in its support for C(1)(b) that monthly inspections and inspections before and immediately after launch are more cost effective and likely as effective in reducing emissions. *See* Textor rebuttal testimony, NMOGA Exhibit 46: 11:31-41.

The Board rejects NMOGA's proposed addition in C(3), regarding portable devices, because portable equipment is already addressed in Section 115, and because monitoring requirements are important. NMOGA's proposed exemption risks creating a major loophole in the rule for portable control devices. The monitoring requirements in Section 20.2.50.115 are appropriate for all control devices and are critical for ensuring that the control devices are operating properly and controlling emissions as intended. Absent periodic monitoring of control device operation and performance, there is no way for the owner or operator or the Department to determine if the equipment is operating properly. NMED Rebuttal Exhibit 1, p. 81.

D. Recordkeeping requirements: In addition to complying with the recordkeeping requirements in 20.2.50.112 NMAC, the owner or operator of an affected pig launching and receiving site shall maintain a record of the following:

(1) the pigging operation, including the location, date, and time of the pigging operation;

(2) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE;

(3) date and time of any monitoring and the results of the monitoring; and

(4) the type of control device and its make and model.

Subsection D of Section 20.2.50.121 sets forth recordkeeping requirements for pig launcher and receiver operations. Owners and operators must maintain records of location, date, and time of the pigging operation; the data and methodology used to estimate the actual emissions and the PTE; date and time of monitoring events and results of the monitoring; and information on any control device used. Owners and operators must comply with the general recordkeeping requirements of Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 119-23, and NMED Rebuttal Exhibit 1, pp. 81-82.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.121 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.121 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 119-23.

Estimated Emissions Reductions from Section 20.2.50.121

Based on the NMED Equipment Data, ERG identified 10 facilities with pigging operations. However, this is not a complete inventory of pigging operations because they are most often located within other facilities and are not identified separately in NMED's permitting and facility databases. Further, pigging operations are also not quantified separately in the data from EPA's Greenhouse Gas Reporting Program for Petroleum and Natural Gas Systems, 40 C.F.R. 98, Subpart W. Of the 10 facilities determined from NMED data, four facilities have five pigging operations with allowable VOC emissions equal to or greater than 1 tpy VOC each. Based on the applicability threshold of 1 tpy VOC, these operations would be required to implement reductions of 98% pursuant to Paragraph (1) of Subsection B of Section 20.2.50.121. Total allowable VOC emissions from these five operations are 24.1 tpy, so the total reductions would be 23.6 tpy VOC based on the 98% control requirement. Total emissions from the pigging operations with emissions below the 1 tpy VOC 98% control applicability threshold are 1.6 tpy VOC, resulting in an overall control efficiency of 92%. NMED Exhibit 32, p. 121.

Estimated Costs for Section 20.2.50.121

EPA Fact Sheet No. 505 provides an estimate of the costs and benefits of capturing liquids and gas from pigging operations. *See* NMED Exhibit 87. According to that document, best management practices for recovery of liquids and gas would require separating pigged liquids from the gas, storing the liquids temporarily at gathering system pressure, and then sending them to a low-pressure storage tank. These liquids (recovered at pipeline pressure) would flash and vent light hydrocarbon gases from the storage tanks. The flash emissions would be recovered by installing a dedicated vapor recovery system on the vessel where the liquids are depressurized. The recovered gas would then be sent to the sales line. This process would reduce emissions and add more gas to the sales line. NMED Exhibit 32, pp. 121-22.

The cost estimates presented in EPA Fact Sheet No. 505 would be appropriate for launching and receiving stations located adjacent to processing plants or pipeline compressor stations that may already have the equipment needed for recovery on-site. In a presentation titled

"Vapor Recovery and Gathering Pipeline Pigging" at the July 2008 Producers and Processors Technology Transfer Workshop in Midland, Texas, EPA provided an example from one Natural Gas STAR Program partner that purchased equipment and implemented this process. *See* NMED Exhibit 89, Slide 35. This company installed a dedicated vapor recovery unit with an electric compressor at an installed cost of $24,000 and an annual operating cost of $40,000 (mostly for electricity). However, based on the value of the condensate recovered, the payback period for the same installation was estimated to be approximately 4 months. *Id.* at 122.

Alternatively, companies may choose to use a temporary skid-mounted flare to meet the control standard for remote pigging operations or pigging operations where the existing infrastructure does not support product recovery. EPA Natural Gas STAR Program's PRO Fact Sheet No. 904, *Install Flares* (2011), provided costs to install and operate a flare at a remote site. *See* NMED Exhibit 90. The estimated implementation cost of a skid-mounted flare is $21,000 and the operating costs per year are $3,000, plus any fuel needed for a pilot light. If the flare were portable, it could be moved to sites on an as-needed basis, with additional cost for transport and set-up added for each pigging operation. *Id.* The Board finds that NMED's estimated costs associated with Section 20.2.50.121 are reasonable and necessary to advance the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

Description of Equipment or Process

Pneumatic controllers are process control devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves. Natural gas-powered pneumatic controllers use natural gas as motive force to operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate in oil and natural gas production and processing. NMED Ex. 34 (EPA CTG). Pneumatic controllers may also be powered by compressed air instead of natural gas. NMED Ex. 32, pp. 122-23. Pneumatic controllers are used to control multiple processes based on a sensed process parameter, such as liquid level in a tank or oil-water separator. Pneumatic controllers can be used as emergency shutoff devices, to regulate flow or liquid levels, or as temperature and pressure regulators. NMED Ex. 10 (MAP Technical Report), *Id.*

VOC and methane emissions occur from natural gas-powered pneumatic controllers when the pressurized gas is directed to atmosphere after the control action is performed. *See* NMED Exhibit 34 (EPA CTG). *Id.* Pneumatic pumps are used to inject chemicals into the wellbore, to circulate glycol in cold climates, and to move liquids from one place to another (sump pumps). Pneumatic pumps range from chemical injection pumps which may inject a few tablespoons of corrosion inhibitor to a well bore, to large diaphragm pumps which move thousands of gallons of product per hour from one tank to another, to pump water out of containment areas after wet weather, or for heat trace to protect pipes from freezing in cold weather. *See* NMED Exhibit 34 (EPA CTG); NMED Exhibit 10 (MAP Technical Report). NMED Exhibit 32, p. 123.

VOC and methane emissions occur from pneumatic pumps when the pressurized natural gas used to drive the pumping action is released to atmosphere after being used for the pumping action. The quantity of VOCs emitted is dependent on the type of pump employed and the concentration of VOCs in the gas stream. *See* NMED Exhibit 10 (MAP Technical Report). *Id.* at 124.

Depending on their intended use, natural gas-driven pneumatic controllers and pumps are available in a variety of designs, but may be characterized by their bleed rate, which is a measure of how much natural gas is used to operate the pneumatic controller or pump, and therefore the emissions from the pneumatic controller or pump. Continuous bleed pneumatic controllers have a continuous supply of natural gas to the process controller (e.g., liquid level control, temperature control, or pressure control) and emit or "bleed" natural gas continuously while the natural gas pressure in the controller is balanced against the process condition (e.g., liquid level, temperature, and pressure), and compared with the associated process set-point. Continuous bleed controllers may either be low bleed (with a bleed or emissions rate less than or equal to 6 standard cubic feet per hour (scfh), or high bleed (with a bleed or emissions rate greater than 6 scfh). Intermittent pneumatic controllers do not vent continuously, but instead release gas only when they open or close a valve, or as they throttle (i.e, adjust) gas flow. The bleed rate from these controllers depends on the amount of gas vented per actuation (i.e., each opening or closing of a valve or adjustment of gas flow) and the frequency of actuation. Zero bleed pneumatic controllers do not bleed natural gas at all. They are self-contained units that release gas to a downstream pipeline. NMED Exhibit 32, pp. 124-25; NMED Exhibit 91 – EPA Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Pneumatic Devices: Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel as part of the President's Climate Action Plan: a Strategy to Reduce Methane Emissions* (April 2014) ("EPA 2014 O&G Pneumatic Devices Report").

Control Options for Pneumatic Controllers and Pumps

There are several ways to reduce emissions from pneumatic controllers, including replacing high bleed controllers with low bleed or zero bleed models, using instrument air rather than natural gas to drive controllers, and using non-gas-driven controllers such as mechanical or electric controllers, including solar-powered controllers. Regular maintenance and proper adjustment of pneumatic controllers can also be used to minimize emissions by repairing leaks and optimizing the amount of gas needed to operate the device. Options for reducing emissions from pneumatic pumps include using instrument air rather than natural gas to drive pumps, using non-gas-driven pumps, such as electric pumps, or routing emissions to a control device or process. NMED Exhibit 32, p. 125; NMED Exhibit 92 – EPA Office of Air and Radiation, *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry* (October 2006).

Rule Language

Proposed Part 50 is based on similar rules for new and existing pneumatic controllers and pneumatic pumps in Colorado Reg. 7, Sections I.K, III.C, and III.D. NMED Exhibit 32, pp. 128-131; NMED Exhibit 39. However, the Department's proposal differs from the Colorado rules in the fundamental approach it takes; specifically, the Department's proposal regulates pneumatic controllers on the basis of controller counts, while the Colorado rules regulate on the basis of total historic liquids production.

In their direct testimony, NMOGA, IPANM, Oxy USA, GCA, CDG, and Kinder Morgan (collectively, "Industry Parties") proposed adoption of the regulatory approach to pneumatic controllers adopted in February of 2021 by Colorado as part of its Regulation 7. At the hearing, NMOGA stated its support for the Department's proposed approach. *See* Tr. Vol. 7, p. 2109:1 – 2110:16 (Smitherman). Following the hearing, NMOGA offered several minor revisions throughout Section 122 intended not to change the stringency of the requirements, but to make the rule more workable in the oilfield. The Department supported these "workability changes," and they are adopted below as noted.

The parties comprising CEP initially supported the Department's proposed approach in their direct testimony, with proposals to shorten the compliance deadlines, increase the number of devices that must be non-emitting for all facilities covered under this Section, and add new additional and maximum percent non-emitting device requirements. In their rebuttal testimony and at the hearing, the CEP Parties changed course and put forth a joint proposal with Oxy USA ("Joint Proposal") advocating the Colorado approach. EDF's witness Dr. McCabe testified that the retrofit schedule in NMED's proposal is slower than Colorado's rule and would result in a lower number of retrofits than the Joint Proposal. Witnesses for the Department disagreed with this assertion and noted that Dr. McCabe did not present any data or analysis to support his assertion, nor did he take into account the higher number of controllers that need retrofitting in New Mexico as compared to Colorado. *See* Tr. Vol. 7, 2237:23 – 2238:12, 2240:5 – 2242:25, 2247:4 – 2256:13. Ms. Kuehn further explained that the Joint Proposal was not fully developed and was missing significant rule language that would be necessary for implementation, such as the method to determine total historic percentage of liquids produced at facilities. *See* Tr. Vol. 7, 2238:13 – 2239:6.

The Board finds that the Colorado approach is not appropriate for New Mexico for the reasons stated in NMED Rebuttal Exhibit 1, p. 83-90. Colorado has regulated pneumatic devices under Colorado Reg. 7, Part D, Section III since 2009. These provisions include emissions reduction requirements for both new and existing pneumatics located within the Denver Front Range (DFR) nonattainment area. Colorado Reg. 7 also has requirements for pneumatics located outside of the DFR nonattainment area that were constructed between May 1, 2014 and May 1, 2021 which require the use of zero bleed pneumatics for facilities with commercial line power, and low bleed pneumatics where line power is not available and it is not technically or economically feasible to retrofit the devices. Part D, Section III was revised in 2017 to include specific requirements for inspections and leak detection and repairs of natural gas driven pneumatics. *See* Colorado Reg. 7, Part D, Section III.F *Pneumatic Controller Inspection and Enhanced Response*. These requirements were initially applied only to nonattainment areas, but were expanded in 2019 to cover other areas of the state.

The result of these prior regulatory efforts is that Colorado, through Reg. 7, has already achieved significant reductions in the overall number of high-bleed pneumatics and their associated emissions, and has implemented a robust inspection and monitoring program to oversee the proper operation of these devices. Thus, Colorado had already reduced emissions by replacing large numbers of high bleed pneumatic controllers and reducing emissions from pneumatic controller malfunctions, before it established the newer targets for non-emitting controllers based on company-wide production. Colorado's new requirements in its recently-adopted rules were developed based on the pre-existing regulatory requirements in that state and in the context of emissions reductions that have already been achieved under those requirements.

The Department's proposal, while premised on a similar but more straightforward concept than that used by Colorado for the new Reg. 7 requirements, does not have the similar advantage of building regulatory provisions off of emission reductions achieved by past regulatory efforts. As a result, the provisions in Section 20.2.50.122 will likely achieve higher emission reductions from pneumatic controllers by targeting reductions in the overall number of emitting controllers, rather than by reducing the fraction of controllers represented by a certain percentage of overall production. At the same time, the Department's approach will also address emissions from pneumatic controller malfunctions by establishing monitoring requirements for all pneumatic controllers to ensure they are functioning properly and emitting only when they should be.

NMED also attempted to design a simpler regulatory scheme for pneumatics than that provided under Colorado's rule, while still providing important flexibilities and workable timeframes. NMED allowed for flexibility so that owners and operators can prioritize the sites and/or controllers that are retrofitted; thereby providing a reasonable compliance timeline for existing sources; allowing for the use of emitting units in certain instances when natural gas driven units are required for safety or process purposes; providing an offramp from the requirements if owners and operators achieve a 75% non-emitting total controller count by January 1, 2025; and allowing owners and operators of units remaining after January 1, 2027 that are not cost effective to retrofit to submit a cost analysis and request a waiver of the retrofit requirements for those remaining units for approval by the Department.

The Department also chose a different approach to addressing economic impacts on small operators than Colorado. Rather than exempting low producing wells from regulatory requirements, as Reg. 7 does, NMED proposed scaled back regulatory requirements to provide regulatory relief for small operators through the small business facility definition. NMED's proposed approach is directly tied to a company's size and revenue, while Colorado Reg. 7 provides a blanket exemption based on average per well production, regardless of company size or revenue. This approach is problematic in New Mexico because it would exempt 269 out of the 324 well operators who have well production, and would exempt 30,200 wells (or 63% of wells) from the non-emitting controller requirements, thereby significantly undermining the purpose of the rule. *See* Tr. Vol. 7, 2243:1 – 2244:5.

The Board finds that NMED's proposed approach is more appropriately designed to provide relief tailored to small companies, without giving an across-the-board exemption for low producing wells which would compromise the fundamental goal of the proposed rule which is to achieve meaningful emissions reductions from oil and gas operations for the benefit of public health and the environment. The Board adopts the Department's approach rather than the approaches set out by the CEP parties or IPANM, based on the Department's supporting evidence above and NMOGA's supporting evidence below, as well additional information below each section.

NMOGA urged the Board to adopt NMED's proposed 20.2.50.122 NMAC (with minor revisions) because it requires reasonable but significant VOCs reductions from pneumatic controllers. NMOGA's proposed minor revisions will improve implementation. These revisions clarify replacement requirements at existing facilities, clarify that compliance is set based on the tables, set forth a compliance methodology for determining compliance on January 1, 2024, 2027 and 2030, and provide greater certainty in handling controllers necessary for safety and process reasons. Increasing the stringency of pneumatics requirements in this rule is unnecessary and, in many respects, impractical.

NMED's proposal requires all new natural gas-driven pneumatic controllers to have an emission rate of zero and a specified percentage of existing controllers to be non-emitting according to the schedule in proposed 20.2.50.122.B(3) NMAC. The proposal ultimately requires anywhere from 80 to 90% of controllers at well sites, tank batteries, and gathering and boosting stations to be non-emitting by January 1, 2030, and 98% of pneumatic controllers at transmission compressor stations and gas processing plants to be non-emitting by January 1, 2030. The proposal also requires new pneumatic diaphragm pumps located at natural gas processing plants to be non-emitting; new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power to be non-emitting; existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power to be non-emitting within two years; and certain pneumatic diaphragm pumps to be controlled by 95% where non-emitting technology is unavailable.

The Department's pneumatic controller proposal is different than Colorado's approach. While Colorado requires phaseout of pneumatic controllers on a production basis, New Mexico has applied a phaseout based on controller count. As Ms. Bisbey-Kuehn and Mr. Palmer explained, Colorado's approach is not appropriate for New Mexico. *See* generally, Tr. 7:2025:20-25 - 2027:1-15. Colorado has been regulating pneumatic controllers since 2009, and it has extensive infrastructure and administrative resources in place necessary to administer a program like Colorado's. Palmer Testimony, Tr. 7:2022:19-23; Bisbey-Kuehn Testimony, Tr. 7:2026:12-22. This is not the situation New Mexico finds itself in, as the state is regulating pneumatic controllers for the first time through proposed Part 50. Bisbey-Kuehn testimony, Tr. 7:2027:4-9. Unlike Colorado, New Mexico does not have the benefit of building the pneumatics program on top of emissions reductions already achieved by past regulatory efforts. Tr. 7:2022:19-23. The current proposal recognizes the status of the industry in New Mexico while requiring leaps forward to achieve significant emissions reductions. A production-based approach should be rejected for these reasons. Bisbey-Kuehn testimony, Tr.7:2028:4-13; Smitherman testimony, Tr. 7:2109:5-18.

Proposed measures to increase the stringency of the Department's proposal would require owners and operators to achieve a fixed increase in the percentage of non-emitting controllers rather than attain a fixed point, require gas driven controllers at gas processing plants or transmission compressor stations to be converted to non-emitting within six months, accelerate the timeline so that all retrofits occur by 2025 rather than 2030, and remove the early action incentive in NMED's proposal. The rationale provided for these changes boils down to Colorado took a similar approach, so New Mexico should too. New Mexico is not Colorado, and the approach taken by another jurisdiction with different challenges and opportunities has little bearing on what's right for New Mexico. These requirements are often not technically or economically feasible and place strains on both the companies and supply chains. Smitherman testimony, Tr. 7:2109:14-7:2110:4. In addition, the only concrete evidence offered by Dr. McCabe for the six-month proposal was that natural gas processing plants were able to achieve this within 6 months in Colorado. McCabe testimony, Tr. 7:2076:14-17; Smitherman testimony, Tr. 7:2108:11-23. But as Dr. McCabe conceded and other witnesses noted, natural gas processing plants are large facilities with electric power that are relatively few in number and were not caught up in the pandemic's supply chain snarls. McCabe testimony, Tr. 7:2076:14-17. There is no compelling evidence in the record that a faster transition is possible and a lot of testimony why it is not given New Mexico's starting point and pandemic impacts.

Requiring retrofit at gas processing plants and transmission compressor stations within six months is also infeasible and unnecessary. Multiple witnesses with direct experience designing systems, planning retrofits, and grappling with current supply chain issues testified that this proposal is unrealistic. *See,* e.g., Tr. 7:2108:11-23; 2214:14-18; 2283:1-8; 2284:9 – 2285:25. Requiring phaseout to be completed by 2025 similarly presents logistical challenges. More importantly, as Mr. McNally testified, "The earlier imposition of VOC controls would have little impact on ozone levels in NM." NMOGA Exhibit 45, at 8.

Finally, NMED is requiring owners and operators to apply leak detection and repair measures to pneumatic controllers and pumps, a measure that significantly reduces the urgency of phaseout. NMED Rebuttal Exhibit 23, 20.2.50.116.C NMAC. Multiple witnesses testified that there are "significant emissions from malfunctioning gas-powered pneumatic controllers" and that applying LDAR to these devices would reduce emissions from these malfunction events. *See*, e.g., Tr. 7:60:6-9; 7:2224:8-24. If these malfunctioning devices are being identified and repaired, then New Mexico has less to gain by hastening their replacement. Tr. 7:2275:4-14. Because NMED's original pneumatics proposal did not contemplate imposing LDAR on pneumatic controllers, its cost-per-ton analysis did not consider emissions reductions attributable to LDAR. *See* NMED Exhibit 95. Consequently, when NMED adopted the pneumatic LDAR proposal, it should have updated its cost-per-ton analysis to include consideration of the LDAR costs and tons reduced before calculating the phase out costs and tons reduced, which would be less. Eliminating this error significantly decreases the cost-effectiveness of the retrofit requirements and counsels against increasing the stringency of the proposal.

NMOGA's workability changes included these: First, all the discussions of the pneumatics program were premised upon units being subject either to Table 1 or Table 2 in 20.2.50.122.B.(3). The compliance methodology in paragraph (4)(b), however, applies to all pneumatic controllers and does not distinguish between the tables. Only sources subject to each Table should be assessed for that table. Second, both NMED and NMOGA have discussed the importance of pneumatic controllers "necessary for safety and process reasons," which NMED has proposed to exclude from the program upon a written demonstration. *See* 20.2.50.122.B.(4)(b)(i), D.(6); Kuehn testimony, Tr. 7:2041:1-5. While all parties likely agree with Ms. Kuehn that it would be "ideal" if these units were identified prior to the start of the program, the reality is that it won't happen. To protect both the ability to maintain these units and the phase out schedule, the initial "total controller count" used to determine the phase out requirements is renamed as the "total historic controller count" so that neither it nor the phase out requirements applicable to an owner/operator are affected by subsequent identification of controllers necessary for safety or process reasons.

Third, and most importantly, the rule does not provide how compliance with the phase out schedule will be demonstrated on the January 1, 2024, January 1, 2027, and January 1, 2030 compliance dates. It is clear from the testimony of all parties that even though Table 1 and Table

2 are phrased "Total Required Percentage of Non-Emitting Controllers by [date]" that the real focus is on replacing natural gas driven controllers with non-emitting ones or eliminating the natural gas driven controllers entirely, without replacement. Both replacement and elimination achieve the goal of reducing emissions. For purposes of demonstrating compliance on January 1, 2024, 2027 and 2030, NMOGA thus proposes that owners/operators will track the number of emitting controllers subject to each table, calculate a percentage of emitting controllers by dividing that total by the total historic controller count for that table, multiply by 100 to make a percent, and then subtract that percent from 100, which gives the "Percentage of Non-Emitting Controllers" required to assess whether the required reduction has occurred. This approach is consistent with NMED's proposal, which states that records of non-emitting controllers are not required (*see* 20.2.50.122.C.(1) and 20.2.50.122.D.(1)) and has the added benefit of focusing on reductions in the number of emitting controllers, the real issue, rather than addition of non-emitting controllers.

Finally, NMOGA believes it is critical to enshrine in the rule language Ms. Kuehn's statement that the rule does not treat replacement of a natural gas driven controller at an existing facility as a "new" controller, but rather as an existing controller. Kuehn testimony, Tr. 7:2039:12-17. This provision is critical to the orderly phase out of controllers. If a controller failure and replacement triggered the "new" requirements, the owners and operators would be forced into unplanned conversions of entire facilities because it is not cost effective to retrofit a single controller. Bisbey-Kuehn testimony, Tr. 7:2039:12-17; McCabe testimony, Tr. 7:2092:7-11.

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

Subsection A of Section 20.2.50.122 applies to natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 122-125.

Oxy USA proposed to exempt pneumatic controllers used for artificial lift from the requirements of this Section. The Board rejects this revision for lack of sufficient evidence in the record. Controllers used for artificial lift can be included in the percentage of controllers that do not need to be non-emitting, and can be addressed through the flexibilities provided in this Section that allow owners and operators to prioritize which controllers are retrofitted or replaced first. *See* NMED Rebuttal Exhibit 1, p. 87-88.

The Board also rejects, IPANM's proposal to exempt well sites or tank batteries with three or fewer controllers. This proposal would effectively exempt nearly all, if not all, controllers located at well sites and tank batteries. Based on the GHGRP data used to develop the cost estimates for the pneumatic controller requirements, well sites and tank batteries in the San Juan Basin have an average of five pneumatic controllers per well and those in the Permian Basin have an average of only one pneumatic controller per well. IPANM did not provide data or testimony on the impact this exemption would have on the number of controllers impacted or how the exclusion would affect costs or emission reductions. *Id.* at 88.

Generally, IPANM's proposals in Section 122 are so extensive that they undo the work of the Department and the other industry parties to set out workable provisions; the Board rejects all of IPANM's proposed revisions in Sections 122A through D as against the weight of the evidence, inconsistent with the work of the other parties, and as not as thoroughly vetted regarding the impact of the rule on the entire regulated community, including the larger producers.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the

requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

Paragraph (1) of Subsection B of Section 20.2.50.122 requires all new natural gas-driven pumps are required to comply with the emission standards of Section 20.2.50.122 upon startup. Paragraph (2) of Subsection B of Section 20.2.50.122 requires existing natural gas-driven pneumatic pumps to comply with the emission standards in Section 20.2.50.122 within three years of the effective date of Part 50. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 125-131.

(3) An owner or operator shall ensure that its existing natural gas-driven pneumatic controller shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

Table 1 – WELL SITES, STANDALONE TANK BATTERIES, GATHERING AND BOOSTING STATIONS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	85%	90%
> 60-75%	80%	85%	90%
> 40-60%	65%	70%	80%
> 20-40%	45%	70%	80%
0-20%	25%	65%	80%

Table 2 – TRANSMISSION COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	95%	98%
> 60-75%	80%	95%	98%
> 40-60%	65%	95%	98%
> 20-40%	50%	95%	98%
0-20%	35%	95%	98%

Paragraph (3) of Subsection B of Section 20.2.50.122 sets forth the required schedules and targets for replacing existing natural gas-driven pneumatic controllers with non-emitting controllers. Table 1 contains the schedule and targets for well Sites, tank batteries, and gathering and Boosting Stations. Table 2 contains the schedule and targets for natural gas compressor stations and gas processing plants. The target is based on the number of pneumatic controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of Part 50. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except pneumatic controllers that are necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 125-131; NMED Rebuttal Exhibit 1, pp. 82-90. The Department's proposal allows owners and operators to prioritize their highest producing sites and sites with utility electric power for retrofitting first. In this regard, there is no material difference between the Department's proposal and those based on the Colorado approach, except that while Colorado mandates that high production sites must be prioritized, NMED's proposal does not, and therefore provides more flexibility to owners and operators to select the most cost-effective sites to be retrofitted first. NMED Rebuttal Exhibit 1, pp. 85-86.

NMOGA's proposed revision to add the words "owner or operator" is made to reflect testimony by Ms. Kuehn and the evident intent of provision to require each owner/operator to reduce the number of pneumatic controllers in its operations by the specified percentage. An individual controller cannot partially reduce emissions but must be retrofitted to a non-emitting controller or replaced or eliminated. The reduction percentages are aimed at the group of existing controllers as an individual controller cannot partially reduce emissions but must be retrofitted to a non-emitting controller or replaced or eliminated. Bisbey-Kuehn testimony, Tr. 7:2027:9-13 (“the proposed provisions of this section will likely achieve higher emission reductions from pneumatic controllers by targeting reductions in the overall number of emitting controllers…”); 7:2029:6-7:2030:9 (referencing changes to the “fleet” of controllers).

CEP and Oxy’s proposed new language in B(1) and (2) and modified compliance table in B(3) are rejected; NMED’s proposal is more workable and straightforward. A six-month compliance deadline for all facilities is unachievable, and Colorado’s program is not equivalent to New Mexico’s because of the prior regulatory work done in Colorado. NMED engaged in extensive discussions with NMOGA and other industry parties to propose a feasible timeline, and there is less support in the record for the proposals by CEP, Oxy. and IPANM.

(4) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero. A natural gas driven pneumatic controller replacing an existing natural gas driven pneumatic controller at an existing facility is an existing pneumatic controller for purposes of Section 20.2.50.122.

(b) owners and operators of existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by July 1, 2023, the owner or operator shall determine the total controller count for all controllers subject to each table separately at all of the owner or operator’s affected facilities that commenced construction before the effective date of this Part. The total controller count for each table must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count. This final number is the total historic controller count. Controllers identified as required for a safety or process purpose after July 1, 2023, shall not affect the total historic controller count.

(ii) determine which controllers in the total controller count for each table are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers for each table by dividing the total historic non-emitting controller count by the total historic controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above for each table, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph

(3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers using the calculation methodology in Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC by January 1, 2025, for either or both table 1 or table 2, the owner or operator is not thereafter subject to the requirements of that table(s) of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(c) owners and operators of existing natural gas driven pneumatic controllers shall demonstrate compliance with tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, on January 1, 2024, January 1, 2027, and January 1, 2030, as follows:

(i) determine which controllers are emitting (excluding pneumatic controllers necessary for safety or process reasons pursuant to Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC) and sum the total number of emitting controllers for table 1 and table 2 facilities separately.

(ii) determine the percentage of non-emitting controllers by using the following equation for table 1 and table 2 facilities separately:

Total percentage of non-emitting controllers = 100 – ((total emitting controllers / total historic controller count) x 100)

(iii) compliance is demonstrated if the Total Percentage of Non-Emitting Controllers calculated pursuant to Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC is less than or equal to the value for that year in the Total Historic Percentage of Non-Emitting Controllers row (as calculated pursuant to Subparagraph (b)(i)-(iv) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC) of table 1 or table 2, as applicable, of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(d) No later than January 1, 2024, a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted only when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller as excepted for process or safety reasons under clause (i) of subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC must prepare and document the justification for the safety or process purpose prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional or inhouse engineer.

(e) Temporary pneumatic controllers that emit natural gas and are used for well abandonment activities or used prior to or through the end of flowback, and pneumatic controllers used as emergency shutdown devices located at a well site, are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(f) Temporary or portable pneumatic controllers that emit natural

gas and are on-site for less than 90 days are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

Paragraph (4) of Subsection B of Section 20.2.50.122 sets forth the emissions standards for natural gas-driven pneumatic controllers. Subparagraph (a) provides that new pneumatic controllers are required to have an emission rate of zero. Subparagraph (b) outlines the process by which owners and operators of existing pneumatic controllers determine what percentage of non-emitting controllers they have to meet, which provisions of Tables 1 and 2 apply, and the replacement schedule they must meet. Subparagraph (c) authorizes pneumatic controllers with a bleed rate exceeding six standard cubic feet per hour if the owner or operator demonstrates that a higher bleed rate is required based on functional needs. Subparagraph (d) exempts temporary pneumatic controllers used for well abandonment activities or prior to flowback and pneumatic controllers used as emergency shut down devices at a well site from the requirements of Subsection B. Subparagraph (e) exempts temporary or portable pneumatic controllers that are onsite for less than 90 days from the requirements of Subsection B.

The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 122-137; NMED Rebuttal Exhibit 1, pp. 83-90; Tr. Vol. 7, 2025:10 – 2033:20; and for the reasons set out by Kinder Morgan and NMOGA, below.

Kinder Morgan notes that the Department confirmed its intent that operators of transmission compressor stations and gas processing plants comply with the requirements of Table 2. *See* Kinder Morgan's Closing Argument at pp. 12-15 for a more detailed history of the evolution of this section. The Board should set aggressive, yet achievable, targets for operators to retrofit or replace existing pneumatic controllers with non-emitting controllers; and the schedules set forth in Tables 1 and 2 achieve this outcome.

NMOGA notes that Ms. Kuehn clearly stated that "like kind replacement" of existing controllers at existing facilities should not trigger the "new" controller provision, to avoid inadvertent or unplanned conversion of facilities. Tr. 7:2039:12-17; NMOGA Exhibit 47, 46:38-40, 48:35 – 49:2. As to (4)(b)(i), Ms. Kuehn stated a general intent to achieve a January 1, 2023 date. Tr. 7:2042:8-11. However, the progress of the rulemaking has been slower, and Ms. Kuehn agreed that more devices may be needed for safety or process purposes, Kuhn/Palmer testimony, Tr. 7:2040:2-2041:5. Mr. Smitherman testified that this couldn't be done in 6 months, Smitherman testimony, Tr. 7:2108:11-27, Ms. Nolting testified that completing the inventory was extremely time consuming already, Tr. 7:2284:19-21, and Ms. Kuehn testified that the documentation was needed only for those that would otherwise be phased out, which suggests a rolling evaluation (for other than high-bleed devices), which reduces the immediate burden. Tr. 7:2041:10-20. Given this testimony and the fact that the first deadline for reductions is January 1, 2024, NMOGA believes that Ms. Kuehn may not have appreciated the infeasibility of the January 1, 2023 date in light of the changes discussed and the role of pneumatic controllers needed for safety or process reasons. The July 1, 2023 date provides more time for the resource intensive inventory. This would also be the date used to "set" the phase out schedule in tables 1 and 2. This then gives owners/operators 66 more months to ensure that they can meet the first phase out deadline on January 1, 2024.

As to the insertions around tables, Ms. Kuehn's testimony is based upon reductions occurring at each "group" of table 1 or table 2 facilities. However, the calculation methodology does not distinguish between the table 1 and table 2 facilities. Separate calculation for each table is needed to create an "apples to apples" comparison to track progress between "historic" and January 1, 2024, January 1, 2027 and January 1, 2030 performance. Otherwise, an operator's failure to make progress at its table 1 sites may result in its table 2 sites being in violation and vice versa. This is surely not the intended result. The final sentence in (4)(b)(i) is added to reflect reality that not all devices required for safety or process reasons will be known by either January 1, 2023 or July 1, 2023. Kuehn/Palmer testimony, Tr. 7:2042:5-7 (conceding that "ideally" the devices could be identified by January 1, 2023). As Mr. Smitherman testified, some of these devices are necessary to provide a safe working environment and the rule needs to allow this. Smitherman testimony, NMOGA Exhibit A1:30:4-16. The change allows for future additions but provides that they do not affect the total historic controller count used to establish obligations under tables 1 and 2. This is consistent with the Department's intent and provides a route to maintain controllers required for safety or process reasons if missed during the initial pass.

The first changes in (4)(b)(v) are added to establish how to count non-emitting controllers for compliance purposes after the initial count. *See* the rationale for Paragraph (4)(c) below for details. The second change is made to reflect Ms. Kuehn's testimony that sources that meet the 75% prior to January 1, 2025 date must still meet the January 1, 2024 reduction percentage. Kuehn/Palmer testimony, Tr. 7:2043:16-7:2045:21.

Regarding new paragraph (4)(c), the rule did does not establish a compliance methodology to demonstrate compliance with the January 1, 2024, 2027 and 2030 compliance dates; new paragraph (4)(c) remedies this. While tables 1 and 2 talk about percent of "non-emitting controllers," for purposes of phasing out, what is important is reducing the number of emitting controllers. In addition, Paragraph (1) of both Subsections C and D do not require records of non-emitting controllers, so there is no non-emitting controller data to use. Therefore, NMOGA clarified the "emitting controller count," excluding pneumatic controllers "permitted" because necessary for safety or process reasons. Kuehn/Palmer testimony, Tr. 7:2041:1-5. NMOGA then proposes use of the equation: 100 – ((existing controller count (in 2024, 2027 or 2030) / total historic controller count) x 100, which gives a final value directly comparable to tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC. If 100% is the total number of emitting and non-emitting controllers, and the percentage of emitting controllers is subtracted, what is left is the percentage of non-emitting controllers.

Regarding the January 2024 date in newly re-lettered paragraph (4)(d), upon reviewing the final language, this provision "phases out" high-bleed devices unless the required demonstration is made, but it cannot be accomplished by the effective date. NMOGA had proposed to phase out all non-safety/process high-bleed controllers within two years. NMOGA's edit aligns the phase out with the January 1, 2024 first compliance date, allowing just less than two-years to inventory and prepare the justification for high bleeds, resulting in an effective phase out. NMOGA Ex. 47, 48:33-34 ("High Bleed Controller shall be retrofitted or replaced no later than January 1, 2024 unless" demonstrated as necessary for safety or process reasons). Certain pneumatic controllers are required for process and safety reasons, and Ms. Kuehn indicated it was not NMED's intent to "freeze" in place high-bleed devices (to qualify for the exception) when low-bleed or intermittent devices might be used. The language changes reflect that discussion and allow lower emitting devices to be substituted for higher emitting ones. This advances the goal of reducing release of natural gas.

The Board rejects the proposed changes by CEP in this section as against the weight of the evidence and in conflict with the Board's prior decisions above. CEP's proposal may have led to faster reductions in emissions, but failed to account for the number of controllers affected, the number of facilities required to comply with this Section, and the time needed to come into compliance, making the proposed timelines impractical and unreasonable. NMED Rebuttal Exhibit 1, pp. 89-90. The Department's proposal set out a very reasonable phased approach; it is not clear that zero emissions are feasible. The Department committed to reviewing waiver requests on a case-by-case basis and will make a determination whether or not the request should be granted, thus ensuring that only reasonable and fully supported waiver requests are allowed. *See id.* at 90.

(5) Standards for natural gas-driven pneumatic diaphragm pumps.

(a) new pneumatic diaphragm pumps located at natural gas processing plants shall have an emission rate of zero.

(b) new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero within two years of the effective date of this Part.

(d) owners and operators of pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic diaphragm pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic diaphragm pump emissions to the control device within two years of the effective date of this Part.

Paragraph (5) of Subsection B of Section 20.2.50.122 sets forth the emissions standards for natural gas-driven pneumatic diaphragm pumps. Natural gas-driven pumps located at natural gas processing plants must have an emission rate of zero. Natural gas-driven pumps located at well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations with access to commercial power must have an emission rate of zero. Owners and operators of pneumatic pumps at well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations without access to commercial line electrical power are required to reduce VOC emissions from this equipment by 95 percent if it is technically feasible to route those emissions to a control device, fuel cell, or process. If an existing on-site control device is not capable of achieving a 95 percent reduction of VOC emissions, and it is not technically feasible to route pneumatic pump emissions to a fuel cell or process, the owner or operator must route the emissions to the existing control device. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 126, 130-38; NMED Rebuttal Exhibit 1, pp. 83-90; Tr. Vol. 7, 2033:21 – 2034:22.

C. Monitoring requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as a motive force are not subject to the monitoring requirements in Subsection C of 20.2.50.122 NMAC.

(2) No later than January 1, 2023, the owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller shall, on a monthly basis, conduct an AVO or OGI inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) Within two years of the effective date, the owner or operator's data systems shall contain the following for each in-service natural gas-driven pneumatic controller:

(a) pneumatic controller unique identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) if continuous, design annual bleed rate in standard cubic feet per year.

(5) Upon the effective date for the facility in 20.2.50.116 NMAC, the owner or operator of a natural gas-driven pneumatic diaphragm pump shall, on a monthly basis, conduct an AVO or OGI inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(6) The owner or operator of a natural gas-driven pneumatic controller shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC applicable to the facility type at which the pneumatic controller is installed on the effective date specified in section 20.2.50.116 NMAC. During instrument inspections, operators shall use RM 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting

when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

(7) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(8) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.122 contains monitoring requirements for pneumatic controllers and pumps. Pneumatic devices that do not use natural gas or other hydrocarbon gas as motive force are exempt from the monitoring requirements. Owners and operators of facilities with pneumatic controllers that are subject to the deadlines in this Section must monitor the compliance status of each controller at each facility; conduct a monthly AVO or OGI inspection; inspect the controller and perform necessary maintenance to maintain the unit in accordance with manufacturer specifications and ensure VOC emissions are minimized; and must maintain the specified information on each controller in a database. Owners and operators of facilities with pneumatic pumps must conduct a monthly AVO or OGI inspection; inspect the pump and perform necessary maintenance to maintain the unit in accordance with manufacturer specifications and ensure VOC emissions are minimized. Pneumatic controllers must comply with the LDAR requirements in Paragraph (3) of Subsection C of Section 20.2.50.116, and owners and operators must verify that intermittent controllers are not emitting when not actuating. If an intermittent controller is found to be emitting when not actuating, it must be repaired in accordance with Subsection E of 20.2.50.116 NMAC. Monitoring events must be date and time stamped. Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112.

The Board adopts the Department's proposal with NMOGA's workability changes, for the reasons stated in NMED Exhibit 32, pp. 127, 130-38; Tr. Vol. 7, 2034:23 – 2036:18; and by NMOGA: The addition of a date in C(2) aligns the start date with completion of the inventory.

The edits in C(4) are appropriate because Paragraph (3) of Subsection A of proposed 20.2.50.112 NMAC provides two years to establish the data system. This provision needs to be consistent as data cannot be recorded until the system is in place. Mr. Smitherman indicated two years would be needed and Ms. Kuehn agreed that such systems take more than a year to set up. Bisbey-Kuehn testimony, Transcript 5:1370:3-8; *see* also Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11. The edits in C(5) and C(6) are appropriate because this is an LDAR requirement. LDAR on a particular piece of a facility should be started when the facility starts LDAR under proposed 20.2.50.116 NMAC. Piecemeal implementation adds cost, double mobilization, and makes compliance difficult as the full LDAR system is not ready prior to its design and implementation under section 20.2.50.116 NMAC. Smitherman testimony, NMOGA Ex. A1:21:16-39.

The Board rejects Oxy's and CEP's proposed changes in Section C as not supported by the record in this matter, as impracticable regarding the Department's enforcement discretion, and as inconsistent with prior decisions related to the tables.

D. Recordkeeping requirements:

(1) Non-emitting pneumatic controllers and diaphragm pumps are not subject to the recordkeeping requirements in Subsection D of 20.2.50.122 NMAC.

(2) The owner or operator shall maintain a record of the total historic controller count for all controllers at all of the owner or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of natural gas-driven pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller. On or before January 1, 2024, January 1, 2027 and January 1, 2030, the owner or operator shall make and retain the compliance demonstration set forth in Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(5) The owner or operator shall maintain an electronic record for each

natural gas-driven pneumatic controller. The record shall include the following:

(a) pneumatic controller unique identification number;

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) name of the person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) AVO or OGI level discrepancy in continuous or intermittent bleed rate;

(f) record of the controller type, bleed rate, or bleed volume required in Subparagraphs (b), (c), (d), and (e) of Paragraph (4) of Subsection C on 20.2.50.122 NMAC.

(g) maintenance date and maintenance activity; and

(h) a record of the justification and certification required in Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC. This demonstration shall be completed by July 1, 2023 for controllers with a bleed rate greater than six scf/hr and as necessary for controllers with a bleed rate less than or equal to six scf/hr.

(7) The owner or operator shall maintain a record for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic diaphragm pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified professional or inhouse engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.122 sets forth recordkeeping requirements for pneumatic controllers and pumps. Pneumatic devices that do not use natural gas or other hydrocarbon gas as motive force are exempt from the monitoring requirements. Owners and operators are required to maintain a total count of all emitting and non-emitting pneumatic controllers at affected facilities that commenced operation prior to the effective date of Part 50 and maintain a total count of units necessary for safety or process purposes that cannot be met without emitting VOC. Owners and operators of affected controllers must develop and record the schedule and compliance status for each controller so that it meets the compliance deadlines.

Owners and operators must maintain an electronic record for each affected controller or pump that contains the ID number, controller type, design continuous bleed rate for continuous controllers, bleed volume per bleed for intermittent controllers, each controller's design annual bleed rate, inspection dates, name of personnel conducting the inspection, AVO inspection result, AVO level discrepancy in continuous or intermittent bleed rate, maintenance date and activity, and a record of the justification for use of a controller with a bleed rate greater than six scfh. Electronic records must be maintained for natural gas-driven pneumatic pumps and the associated pump numbers that have emission rates greater than zero. The record must include the dates of operation for any pump operating less than 90 days per calendar year; any control device designed to achieve at least 95% emission reduction, including an evaluation or the manufacturer specifications indicating percent reduction the control device is designed to achieve; and documents of engineering assessments and certifications from a qualified professional engineer stating that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts the Department's proposal, with NMOGA's workability edits, for the reasons stated in NMED Exhibit 32, pp. 127, 130-38; Tr. Vol. 7, 2036:19 – 2038:5; and by NMOGA: in D(2), the word "historic" is added for consistency with NMOGA's edits in Section C. In D(4) the last sentence is added to memorialize the compliance demonstration contemplated in new paragraph (4)(c) of Subsection B of 20.2.50.122 NMAC. In D(6) the last sentence is added to harmonize the recordkeeping provision with the schedule for phase out of High Bleed

Controllers while allowing for the designation of smaller units; *see* Bisbey-Kuehn testimony, Tr. 7:2040:17-7:2041:9.

The Board rejects CEP's changes in Section D as against the weight of the evidence and conflicting with the Board's prior decisions in Section 122.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.122 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.122 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 127, 130-38.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.122

ERG estimated the overall emission reductions from Section 20.2.50.122 to be 31,347 tpy of VOC. ERG estimated that these reductions would be achieved at an overall cost effectiveness of $2,475 per ton of VOC. A detailed explanation of this analysis is provided in NMED Exhibit 32, pp. 131-37; NMED Exhibit 95 – Pneumatics Reductions and Costs Spreadsheet; and Tr. Vol. 7, 2023:14-23.

The Board finds that NMED appropriately relied upon the well-established emission factors accepted by other state agencies and EPA, and required for federal greenhouse gas reporting to estimate the emission reductions and costs of this proposed rule. *See* NMED Rebuttal Exhibit 1, p. 87. The Board finds that NMED's estimated costs associated with Section 20.2.50.122 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.123 STORAGE VESSELS

Description of Equipment or Process

Storage vessels, commonly referred to as "storage tanks" or "tanks," are used throughout the oil and gas industry for storing a variety of liquids including crude oil, condensates, and produced water. These tanks are associated with oil and gas production, gathering, processing, and disposal and are significant sources of VOC emissions. Storage vessels can be installed as a single unit or in a grouping of similar or identical vessels, commonly referred to as a “tank battery.” The reason for temporary storage is for feasibility of takeaway via pipeline or truck. NMED Exhibit 32, pp. 138-39.

While underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed, and any oil and water remain together) or a three-phase separator (where the associated gas is removed, and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released as vapors in the storage vessels. *Id.* at 139.

Hydrocarbon emissions from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into a storage vessel at atmospheric pressure from a processing vessel (e.g., a separator) operated at a higher pressure. In general, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and the expansion and contraction of stored fluids resulting from increased or decreased pressures associated with environmental and weather-related fluctuations. Working losses occur when vapors are displaced due to the emptying and filling of a storage vessel. *Id.*

The mass of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming off of the oil. The composition of the vapors from storage vessels varies, and the largest component is methane, but may also include ethane, butane, propane, and hazardous air pollutants such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane. *Id.* at 140.

Control Options for Storage Vessels

The methods typically used to reduce VOC emissions from storage tanks are: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled or recovered (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite; and/or (2) route emissions from the storage vessel to a combustion device. NMED Exhibit 32, pp. 140-43.

Rule Language

The proposed requirements in Section 20.2.50.123 are based on similar rules for new and existing storage vessels in Pennsylvania GP-5 and GP-5A, Colorado Reg. 7, and NSPS Subpart OOOOa. *See* NMED Exhibit 32, pp. 146-47; NMED Exhibits 37, 38, and 39.

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels with a PTE equal to or greater than three tpy of VOC in multi-tank batteries, and existing storage vessels with a PTE equal to or greater than four tpy of VOC in single tank batteries are subject to the requirements of 20.2.50.123 NMAC.

Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels. Storage vessels associated with produced water management units are required to comply with this Section to the extent specified in Subsection B of Section 20.2.50.126 NMAC.

Subsection A of Section 20.2.50.123 specifies the storage vessels to which Part 50 applies. Applicability is based on the PTE of the storage vessel, which is further delineated based on whether the vessel is classified as new or existing, and for existing storage vessels, whether the vessel is part of a multi-tank battery, or a single tank battery. New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels with a PTE equal to or greater than 3 tpy in multi-tank batteries, and existing storage vessels with a PTE equal to or greater than 4 tpy in single tank batteries must comply with the requirements of Section 20.2.50.123. The Department also proposed a sentence at the end of Subsection A to align the requirements in Section 20.2.50.123 with the requirements for produced water management units in Section 20.2.50.126.

Initially, the Department proposed that storage vessels with an uncontrolled PTE equal to or greater than 2 tpy were required to comply with this Section. *See* NMED Ex. 32, pp. 144, 146-47. NMOGA proposed to revise the threshold for existing storage vessels to 6 tpy. The Department did not agree with that proposal, based on the higher cost effectiveness for controlling the smallest tanks, but in its rebuttal testimony revised its proposal to raise the applicability threshold for existing storage tanks to 3 tpy. *See* NMED Rebuttal Ex. 1, p. 91. NMOGA presented testimony demonstrating that storage vessels in single tank batteries in New Mexico are particularly problematic with respect to the cost-effectiveness of retrofitting or replacing these tanks due to their lack of available headspace to moderate demands on the control system combined with the typical age and pressure ratings of such tanks in New Mexico. *See* Tr. Vol. 9, 2094:11 – 2914:17. NMOGA witness Adam Meyer pointed out that the Department's cost analysis had not taken into account certain costs associated with replacing these tanks. *See* Tr. Vol 9, 3035:15 – 3036:21, 3092:10 – 3094:16. Based on the single tank spreadsheet prepared by NMED witness Mr. Palmer and submitted at the hearing as NMED Rebuttal Exhibit 29, a threshold of 3 tpy for these tanks results in a cost effectiveness of $9,176/ton, which NMED agreed is on the high side. *See* Tr. Vol 9, 3092:10 – 3094:16.

While NMOGA's proposed 6 tpy threshold would result in a cost effectiveness of $4,558/ton, it would also leave far more storage vessels unregulated resulting in significantly fewer emissions reductions. *See* Tr. Vol. 9, 3034:8-24. NMED has proposed a threshold of 4 tpy for existing storage vessels in single tank batteries which results in a cost effectiveness of $6,876/ton. NMED Rebuttal Exhibit 29.

The Board adopts the Department's proposal because it strikes a reasonable balance between the costs to industry and the emissions reductions necessary to effectuate the purpose of the statute. The Department did include a proposal by NMOGA to allow averaging among storage vessels that vapor manifolded together to determine an individual vessel's PTE for purposes of determining applicability of this Section. The Board adopts this proposal for the reasons stated in NMED Rebuttal Ex. 1, p. 92.

The use of PTE to determine applicability of air quality regulations and permit requirements is a common and long-standing practice utilized by state and federal air quality regulatory agencies. The use of actual emissions to determine applicability is not acceptable, as that calculation is based on previous years' records of the operation of a source, which may not be representative of a source's future operations or emissions. Because actual emissions can change year to year depending on numerous factors (e.g., economics, regulatory requirements, political decisions, consumer demand, market conditions), that measure is not a reliable or representative emission rate with respect to determining applicability under this Section. PTE is a source's maximum capacity to emit an air pollutant under its physical and operational design, and is a much more accurate and reliable estimation of the source's emissions. NMED Rebuttal Ex. 1, pp. 91-92. The Board rejects the proposed changes offered in this Section by CDG, CEP, and NMOGA due to lack of adequate supporting evidence. NMED's language is clear and consistent, and its 4 tpy threshold is the middle ground between CEP and NMOGA.-

B. Emission standards:

(1) An existing storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent according to the following schedule. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(a) By January 1, 2025, an owner or operator shall ensure at least 30% of the company's existing storage vessels are controlled;

(b) By January 1, 2027, an owner or operator shall ensure at least an additional 35% of the company's existing storage vessels are controlled; and

(c) By January 1, 2029, an owner or operator shall ensure the company's remaining existing storage vessels are controlled.

Paragraph (1) of Subsection B of Section 20.2.50.123 sets forth the emission standard for existing storage vessels to which this Section applies. Existing tanks must have a combined capture and control of VOC emissions of at least 95%. If a combustion device is used, it must have a minimum design combustion efficiency of 98%. Owners and operators of existing tanks must been these standards on the phased-in schedule set forth in Subparagraphs (a) through (c) of Paragraph (1). The Department proposed adding the phase-in schedule in response to comments from Oxy USA. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148; NMED Rebuttal Exhibit 1, p. 93; and Tr. Vol. 9, 2898:17 – 2900:9, 3030:19 – 3031:3.

(2) A new storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

Paragraph (2) of Subsection B of Section 20.2.50.123 sets forth the emission standards for new storage vessels. New tanks have the same emission standard as existing tanks, but new tanks must meet this standard upon startup; there is no phased-in compliance schedule. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148.

(3) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the actual annual VOC emissions decrease to less than two tpy.

Paragraph (3) of Subsection B of Section 20.2.50.123 provides that the emissions standards in Subsection B cease to apply if the actual annual emissions of an affected storage vessel fall below 2 tpy. The intent of the rule is to require meaningful reductions in storage vessel emissions; a higher threshold would exempt an unknown number of storage vessels from control requirements. NMED Rebuttal Exhibit 1, p. 93. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148.

(4) If a control device is not installed by the date specified in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

Paragraph (4) of Subsection B of Section 20.2.50.123 allows an owner or operator who fails to install a control device by the specified dates to comply with the emission standards in Subsection B by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device has been installed and operational. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148.

Limiting a source’s throughput or emissions is already an option available to owners and operators and can be achieved by obtaining an air permit with federally enforceable limits. *See* NMED Rebuttal Exhibit 1, pp. 93-94. This provision is not a requirement, but rather one option for compliance. NMED’s phased-in compliance schedule addresses Oxy’s concerns, and the compliance deadlines are reasonable. *Id.* at 94.

(5) The owner or operator of a new or existing storage vessel with a thief hatch shall ensure that the thief hatch is capable of opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. Any pressure relief device installed must automatically close once the vessel overpressure is relieved.

Paragraph (5) of Subsection B of Section 20.2.50.123 requires owners and operators new or existing storage vessel equipped with a thief hatch to ensure that the thief hatch can open sufficiently to relieve vessel overpressure, and to automatically close once the vessel overpressure has been relieved. Pressure relief devices must automatically close once the overpressure is relieved. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148 and NMED Rebuttal Exhibit 1, p. 94.

(6) An owner or operator complying with Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

Paragraph (6) of Subsection B of Section 20.2.50.123 requires that owners or operators that employ a control device to comply with the emission standards of this Section must also comply with the control device operational requirements of 20.2.50.115 NMAC. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-48, and NMED Rebuttal Exhibit 1, pp. 94-95.

Authorization for alternative controls is already incorporated into the definition of Control Device which states “A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.” The Department supports innovative approaches to controlling emissions from low emitting storage vessels. The rule requires 95% control but does not specify how that control level is to be achieved. The rule does specify that if a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent. NMED

Rebuttal Exhibit 1, pp. 94-95. NMED's proposed language in Section 20.2.50.126 addresses the concerns raised by CDG. *Id.* at 95.

C. Storage vessel measurement requirements: Owners and operators of new storage vessels required to be controlled pursuant to this Part at well sites, tank batteries, gathering and boosting stations, or natural gas processing plants shall use a storage vessel measurement system to determine the quantity of liquids in the storage vessel(s). New tank batteries receiving an annual average of 200 bbls oil/day or more with available grid power shall be outfitted with a lease automated custody transfer (LACT) unit(s).

(1) The owner or operator shall keep thief hatches (or other access points to the vessel) and pressure relief devices on storage vessels closed and latched during activities to determine the quantity of liquids in the storage vessel(s), except as necessary for custody transfer. Tank batteries equipped with LACT units shall use the LACT unit measurements in lieu of field testing of quantity and quality except in case of malfunction. Nothing in this paragraph shall be construed to prohibit the opening of thief hatches, pressure relief devices, or any other openings or access points to perform maintenance or similar activities designed to ensure the safety or proper operation of the storage vessel(s) or related equipment or processes. Where opening a thief hatch is necessary, owners and operators of new and existing storage vessels shall minimize the time the thief hatch is open.

(2) The owner or operator may inspect, test, and calibrate the storage vessel measurement system either semiannually, or as directed by the Bureau of Land Management (*see* 43 C.F.R. Section 374.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening a thief hatch if required to inspect, test, or calibrate the vessel measurement system is not a violation of Paragraph (1) of this Subsection.

(3) The owner or operator shall install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(4) The owner or operator shall develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(5) The owner or operator must make and retain the following records for at least two years and make such records available to the department upon request:

(a) date of construction of the storage vessel or facility;

(b) description of the storage vessel measurement system used to comply with this Subsection;

(c) date(s) of storage vessel measurement system inspections, testing, and calibrations that require opening the thief hatch pursuant to Paragraph (1) of this Subsection;

(d) manufacturer specifications regarding storage vessel measurement system inspections and calibrations, if followed pursuant to Paragraph (2) of this Subsection; and

(e) records of the annual training program, including the date and names of persons trained.

Subsection C of Section 20.2.50.123 contains the automatic tank gauging proposal put forward by CEP and Oxy USA in the Joint Proposal, with certain revisions made by the Department. The Department generally supported the use of a storage vessel measurement system on new storage vessels to determine the quantity of liquids in the vessels. *See* Tr. Vol. 9, 3031:9-23 (Bisbey-Kuehn). CAA witness Dr. McCabe testified that CAA wanted the automatic tank gauging requirement to cover opening the thief hatch to check for quality as well as quantity, and that this could be done by employing automatic tank gauging systems and lease automatic custody transfer, or LACT, units. *See* Tr. Vol. 9, 3010:13 – 3011:6. NMOGA witness Mr. Smitherman testified that there are no real options for measuring quality except through use of a LACT unit. *See* NMOGA Exhibit 41, p. 11. Dr. McCabe stated that the intent of the CAA proposal was not to require a LACT unit. *See* Tr. Vol. 9, 3016:5-9. The Department's final proposal prohibits opening thief hatches to check for quantity; requires a LACT unit under specified circumstances; and, where there is a LACT unit, requires use of the LACT unit measurements in lieu of field testing of quantity and quality, except in cases of malfunction.

The Board adopts the Department's proposal, and rejects the further revisions offered by CEP, Oxy, and NMOGA for lack of justification in the record, as not clarifying, and as inconsistent with the previously accepted definition of "reconstruction" in this rule.

D. Monitoring requirements: No later than January 1, 2023, the owner or operator of a storage vessel shall:

(1) on a monthly basis, monitor, calculate, or estimate, the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig) if the storage vessel is directly downstream of a separator. When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the storage vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel

does not have a leak;

(4) prior to any monitoring event, date and time stamp the event and enter the monitoring data in accordance with the requirements of this Part;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements of 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.123 sets forth the monitoring requirements for storage vessels. These include monitoring, calculating, or estimating total monthly liquid throughput and the upstream separator pressure; inspecting the vessel monthly to ensure compliance with Section 123, and date and time stamping the inspection; complying with the monitoring requirements in Section 115 if using a control device; and complying with the general monitoring requirements in Section 112. The Department proposed additional language specifying a compliance timeline for the monitoring requirements, which is reasonable. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-48 and NMED Rebuttal Exhibit 1, pp. 95-96.

E. Recordkeeping requirements: No later than January 1, 2023, the owner or operator of a storage vessel shall comply with the following requirements:

(1) Monthly, maintain a record for each storage vessel of the following:

(a) unique identification number and location (latitude and longitude);

(b) monitored, calculated, or estimated monthly liquid throughput;

(c) the upstream separator pressure, if a separator is present;

(d) the data and methodology used to calculate the actual emissions of VOC (tpy);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) Verify each record of liquid throughput by dated liquid level measurements, a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) Make a record of the inspections required in Subsections C and D of 20.2.50.123 NMAC, including:

(a) the date and time stamp, including GPS of the location, of the inspection;

(b) the person(s) conducting the inspection;

(c) a description of any problem observed during the inspection; and

(d) a description and date of any corrective action taken.

(4) Comply with the recordkeeping requirements in 20.2.50.115 NMAC if complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection E of Section 20.2.50.123 sets forth the recordkeeping requirements for storage vessels. These include monthly liquid throughput calculations or estimates and the most recent date of measurement; upstream separator pressure; data and methodology used to calculate actual emissions of VOCs; the controlled and uncontrolled VOC emissions; and the type, make, model, and identification number of any control device. A record of liquid throughput must be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer. Owners and operators are required to maintain records of the inspections conducted in accordance with Section 20.2.50.123 and records required by Section 20.2.50.115 if using a control device to comply with the emission standards of this Section, and must comply with the general recordkeeping requirements of Section 20.2.50.112. The Department also proposed additional language specifying a compliance timeline for the recordkeeping requirements, which the Department believes is reasonable. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-48, and NMED Rebuttal Exhibit 1, p. 96.

F. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.115 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

An owner or operator must comply with the reporting requirements of Section 20.2.50.115 if using a control device, and must comply with the general reporting requirements in Section

20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 146-48.

Estimated Emissions Reductions and Costs of Section 20.2.50.123

ERG estimated the overall emission reductions from Section 20.2.50.123 to be 7,739 tpy of VOC for an overall reduction of 48%. ERG estimated that these reductions would be achieved at an overall cost effectiveness of $2,695 per ton of VOC. A detailed explanation of this analysis is provided in NMED Exhibit 32, pp. 147-48; NMED Exhibit 100 – Storage Tanks Reductions and Costs Spreadsheet; NMED Rebuttal Exhibit 28 – Updated Storage Tanks Reductions and Costs Spreadsheet; and NMED Rebuttal Exhibit 29 – NMED Single Tank Cost Estimate Spreadsheet. The Board finds that NMED's estimated costs associated with Section 20.2.50.123 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.124 WELL WORKOVERS

Description of Equipment or Process

Some wells require supplementary maintenance to maintain production or minimize the decline in production. These operations are referred to as workovers. Typical workovers include rod, tubing and casing repairs; siphon string or artificial lift installation paraffin removal; and pump repairs. Workovers are performed on wells that have previously been completed and have produced some reservoir fluids (water, oil, and/or natural gas). These wells have to be prepared before workover operations can begin. If the well is still producing and/or has pressure, the well will need to be blown down (i.e., vented) before it is safe to remove the tubing head and install the blowout preventers (BOPs). The well pressure can be decreased by venting to the atmosphere or by opening the casing to the sales line or the suction of a wellsite compressor.

In many cases, the fluids in the wellbore will build up to the point the well "dies" – this refers to the instance where the hydrostatic pressure of the accumulated fluids is equal to the reservoir pressure. In some cases, it will be necessary to pump water or other fluids into the wellbore to "kill" the well. As a safety precaution, after the BOPs are installed, the well is usually vented to atmosphere via a tank. Workovers are usually short duration projects that only last a few days or weeks at the most. After the well is prepared (i.e., blown down and BOPs installed), the workover operations can begin. For the safety of the rig crew, the well is usually allowed to vent to atmosphere via a tank for the duration of the workover. Since these operations are typically performed during daylight hours, the well is shut in or returned to the sales line at the end of the day. NMED Exhibit 32, pp. 149-50.

Control Options for Well Workovers

Best management practices are the best means of reducing emissions during well workovers. These include reducing wellhead pressure before blowdown to minimize the volume of natural gas vented; monitoring manual venting at the well until the venting is complete; and routing natural gas to the sales line, whenever possible. NMED Exhibit 32, p. 150.

Rule Language

The proposed requirements for workover operations are based on requirements in Colorado Reg. 7 and Wyoming's Permitting Guidance, as detailed in NMED Exhibit 32, pp. 151-52.

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

Section 20.2.50.124 applies to workovers performed at oil and natural gas wells. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 149-152.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering or operational practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;
(2) monitor manual venting at the well until the venting is complete; and
(3) route natural gas to the sales line, if possible.

Subsection B of Section 20.2.50.124 sets forth emission standards for well workovers. The owner or operator of an oil or natural gas well must use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering or operational practices: (1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented; (2) monitor manual venting at the well until the venting is complete; and (3) route natural gas to the sales line, if possible. NMED made revisions to these provisions based on comments by NMOGA and IPANM as outlined in NMED Rebuttal Exhibit 1, p. 97. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 151-152, and NMED Rebuttal Exhibit 1, p. 97.

C. Monitoring requirements:
(1) The owner or operator shall monitor the following parameters during a workover:
(a) wellhead pressure;
(b) flow rate of the vented natural gas (to the extent feasible); and
(c) duration of venting to the atmosphere.
(2) The owner or operator shall calculate the estimated volume and mass of VOC vented during a workover.
(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Subsection C of 20.2.50.124 sets forth monitoring requirements for well workover operations. During a well workover, an owner or operator is required to monitor wellhead pressure, natural gas venting flow rate, and elapsed venting time in order to estimate volume and mass of VOC vented during a well workover. Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112. NMED made revisions to these provisions based on comments by NMOGA and IPANM as outlined in NMED Rebuttal Exhibit 1, p. 97. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 151-152, and NMED Rebuttal Ex. 1, p. 97.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following record for a workover:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the best management practices used to minimize release of VOC emissions before and during the workover;

(g) calculation of the estimated VOC emissions vented during the workover based on the duration, volume, and gas composition; and

(h) the method of notification to the public and proof that notification was made to the affected public.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.124 sets forth recordkeeping requirements for well workovers. For each workover, the owner or operator must record the identification number and location of the well; date; wellhead pressure; flow rate or maximum potential flow rate; duration of venting; best management practices used; and the estimated VOC emissions released; and method of notification to the public and proof of notification as required in Subsection E of Section 20.2.50.124. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. NMED made revisions to these provisions based on comments by NMOGA and IPANM as outlined in NMED Rebuttal Exhibit 1, p. 97. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 151-152, and NMED Rebuttal Exhibit 1, p. 97.

E. Reporting requirements:

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail, or

by other effective means of notice so long as the notification can be documented, all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

(3) If the workover is needed for routine or emergency downhole maintenance to restore production lost due to upsets or equipment malfunction, the owner or operator shall notify all residents located within one-quarter mile of the well of the planned workover at least 24 hours before the workover event.
[20.2.50.124 NMAC - N, XX/XX/2021]

Subsection E of 20.2.50.124 sets forth reporting requirements relating to well workovers. Owners and operators must comply with the general reporting requirements in Section 20.2.50.112. When venting cannot be avoided, the owner and operator must notify all residents located within one-quarter mile of the well at least three days before the workover by certified mail or other effective means of notice. NMED made revisions to these provisions based on comments by NMOGA, as outlined in NMED Rebuttal Exhibit 1, p. 97. Specifically, NMED added a new paragraph to this Subsection providing an exception to the 3-day notification requirement in Paragraph (1) for emergency or routine workovers due to upsets or equipment malfunctions, allowing notification of the public within 24 hours of the event. The Board adopts the Department's proposal for the reasons stated in NMED Ex. 32, pp. 151-152, and NMED Rebuttal Ex. 1, p. 97.

IPANM proposed to remove the entire requirement at Paragraphs (2) and (3) to notify residents within ¼ mile of the well by certified mail within three calendar days of the workover event. The Department disagreed with this proposal. However, NMED did modify this requirement to allow other notification options besides certified mail, so long as they can be documented. NMED recognized that there are other effective means to notify the public of these activities, and certified mail is not the only option to provide this notification. Possible alternatives include notices via text or email. The Board rejects IPANM's proposal, as supported by NMOGA, for these reasons, *see* NMED Rebuttal Exhibit 1, p. 97, and as not supported by the evidence.

The Board rejects Oxy's proposal of an additional paragraph under Subsection E to make the notification requirements in Subsection 124 consistent with the use of "occupied areas" in Section 116 as not supported by the evidence.

The Board rejects NMOGA's argument that the record does not support adoption of the workover proposal at Section 124, based on the reasons offered by the Department as well as CAA Exhibits 13 and 14.

The Board finds, based on substantial evidence, that the workover proposal at Section 124 is more protective of public health and the environment.

Estimated Costs and Emissions Reductions from Section 20.2.50.124

Emission estimates for workover operations are not currently available in the modeling emissions inventory or found in the NMED Equipment Data. Therefore, no estimate of emissions reductions is currently available. Section 20.2.50.124 specifies certain best management practices that must be used when conducting well workover operations, but does not require the use of emission control devices. It is expected that these practices will require personnel to manage the well during the workover operation, but no capital costs are anticipated. Costs associated with well workover best management practices are expected to be minimal as personnel will already be onsite conducting the well workover and any additional training may be incorporated into existing personnel training programs. NMED Exhibit 32, p. 152. The Board finds that NMED's estimated costs associated with Section 20.2.50.124 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to Sections 20.2.50.125 NMAC and 20.2.50.127 NMAC of this Part. Small business facilities are not subject to any other requirements of this Part unless specifically identified in 20.2.50.125 NMAC.

Section 20.2.50.125 applies to small business facilities as defined in Section 20.2.50.7. The Department proposed additional language to clarify what sections of Part 50 apply to small business facilities. The Board adopts this proposal for the reasons stated in NMED Ex. 102, pp. 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (9) of Subsection A of 20.2.50.112 NMAC if requested by the department.

Subsection B of Section 20.2.50.125 sets forth general requirements for small business facilities including operating equipment in accordance with manufacturer specifications and keeping those specifications on file; calculating the annual VOC and NOx emissions from each facility using the actual production and processing rates; maintaining a company-wide database of emission calculations for all subject facilities; and complying with third party verification requirements if requested by the Department. The Board adopts this proposal for the reasons stated in NMED Exhibit 102, pp. 13-15 and NMED Rebuttal Exhibit 1, pp. 97-99.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC. The owner or operator shall comply with Subsection B of 20.2.50.111 NMAC in determining applicability of the requirements in 20.2.50.116 NMAC.

Subsection C of Section 20.2.50.125 requires owners and operators of small business facilities comply with the fugitive leak monitoring requirements in Subsections C and D of Section 20.2.50.116. No party specifically commented on Subsection C or provided suggested revisions.

The Department is proposing to add a reference to the PTE calculation requirements in Section 20.2.50.111 to clarify applicability of those provisions. The Board adopts this proposal for the reasons stated in NMED Exhibit 102, pp. 13-15. and NMED Rebuttal Exhibit 1, pp. 97-99.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

Subsection D of Section 20.2.50.125 requires owners or operators of small business facilities to repair equipment leaks as specified in Subsection E of Section 20.2.50.116. No party specifically commented on Subsection D or provided suggested revisions. The Board adopts this proposal for the reasons stated in NMED Exhibit 102, and NMED Rebuttal Exhibit 1, pp. 97-99.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated annual VOC and NO_x emissions from each facility and the company-wide annual VOC and NO_x emissions for all subject facilities; and

(3) records as required under Subsection F of 20.2.50.116 NMAC.

Subsection E of Section 20.2.50.125 sets forth recordkeeping requirements for owners of small business facilities, including completing an initial certification certifying that the small business facility meets the definition of small business facility in Part 50, and annual certifications thereafter; and calculating annual VOC and NOx facility emissions and the company-wide emissions for all subject facilities. No party specifically commented on Subsection E or provided suggested revisions. The Board adopts this proposal for the reasons stated in NMED Exhibit 102, pp 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 of each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

Subsection F of Section 20.2.50.125 requires owners and operators to submit a certification that they meet the definition of small business facility within the specified time frames. Owners and operators must also comply with the general reporting requirements in Section 20.2.50.112. No party specifically commented on Subsection F or provided suggested revisions. The Board adopts this proposal for the reasons stated in NMED Exhibit 102, pp. 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.
[20.2.50.125 NMAC - N, XX/XX/2021]

Subsection G of Section 20.2.50.125 contains an important provision that triggers the applicability of the remaining sections and requirements of Part 50 if the Secretary of the Department finds, based on credible evidence, that the facility presents an imminent threat to public health or welfare or to the environment; is not being operated in a manner that minimizes emissions of air contaminants; or has violated another requirement of Section 20.2.50.125 NMAC. This provision incentivizes owners and operators of small business facilities to fully comply with Section 20.2.50.125 providing for an applicability onramp for the other sections of Part 50 if they fail to do so. The annual emissions data collected and reported to the Department will be used in air quality planning projects, air dispersion modeling analyses, air emissions databases and emissions inventories, and in other air quality related projects. The Board adopts this proposal for the reasons stated in NMED Exhibit 102, p 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99. The Board rejects IPANM's proposal, as supported by NMOGA, to delete Subsection G in its entirety as against the weight of the evidence.

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

Description of Equipment or Process

The majority of oil- and gas-bearing formations also contain naturally occurring water, often referred to as "formation" or "connate" water. When oil or gas is extracted, this "produced water" is also extracted as a by-product. The actual amount of produced water varies widely depending on factors such as location or stage in the lifetime of a particular well. In addition to reflecting the chemical makeup of the geologic formation from which it is extracted, produced water will also contain suspended solids, dissolved solids, varying amounts of oil residues and organics containing VOCs, and the various chemicals used in the production process. Produced water from gas production typically has higher contents of low molecular-weight aromatic hydrocarbons, such as benzene, toluene, ethylbenzene, and xylene (BTEX) than produced water from oil production. NMED Exhibit 32, p. 153.

<u>Conventional Oil and Gas</u>

On average, about 7 to 10 barrels, or 280 to 400 gallons, of water are produced for every barrel of crude oil. Oil reservoirs commonly contain larger volumes of water than gas reservoirs because gas is stored and produced from less porous reservoirs that contain source rock with a lower water capacity. Produced water generation commonly increases over time in conventional reservoirs as the oil and gas is depleted during hydrocarbon production. *Id.* at 153-54.

<u>Unconventional Oil and Gas</u>

Produced water from most unconventional resources, besides coal bed methane, is minimal due to tighter reservoir formations such as tight sands, oil shale, and gas shale reservoirs. Producers commonly import water to these operations for onsite use in drilling, fracturing, and production. Fresh water used in drilling applications for fracturing is contaminated by the saline water in the reservoir. Fresh water brought onsite for use in operations, such as flow back or water returning from fracturing applications ("frac water"), also is managed as a waste stream. This waste stream is commonly associated with the initial phase of well development and production. In most unconventional oil and gas operations, frac water is considered the largest waste stream of production. *Id.* at 154.

Control Options

VOC emissions from PWMU can be reduced by treating the produced water to remove hydrocarbons before the water enters the recycling facility or impoundment. The emissions are reduced when produced water is processed through three-phase separators and storage vessels, which separates the hydrocarbons from the produced water prior to sending to a PWMU. NMED Exhibit 32, p. 154.

A. Applicability: Produced water management units as defined in this Part and their associated storage vessels are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

Section 20.2.50.126 applies to produced water management units (PWMU) as defined in Part 50. PWMUs and their associated storage vessels must comply with the requirements in Section 20.2.50.126 no later than 180 days after the effective date of Part 50. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 153-56, and NMED Rebuttal Exhibit 1, pp. 99-100.

The Board's air permitting regulations already require owners and operators to submit Notice of Intent (NOI) registrations or air permit applications if the emissions exceed applicability thresholds and, thus, the proposed requirement is redundant with other existing regulatory requirements. NMED disagrees that Part 50 should not apply to a permitted PWMU; Part 50 is intended to apply to all subject sources, regardless of permitting status. NMED Rebuttal Exhibit

1, p. 100. OCD's regulatory authority is based on preventing waste of a resource under the Oil and Gas Act; it does not regulate emissions of air pollutants for purposes of meeting national ambient air quality standards. OCD's requirements are not equivalent to the requirements of Part 50, and do not require reductions of VOC emissions using best management practices. There is no basis for exempting facilities from compliance with Part 50 on the basis that they are permitted or registered with OCD under a different set of regulations and statutory authority. *See* NMED Rebuttal Exhibit 1A, p. 2.

B. Emission standards:

(1) The owner or operator shall use good operational or engineering practices to minimize emissions of VOC from produced water management units (PWMU) and their associated storage vessels.

(2) The owner or operator shall not allow any transfer of untreated produced water to a PWMU without first processing and treating the produced water in a separator or storage vessel to minimize entrained hydrocarbons.

(3) Within two years of the effective date of this Part for storage vessels associated with existing PWMUs, or upon startup for storage vessels associated with new PWMUs, the owner or operator shall either:

(a) control such storage vessels in accordance with the requirements of Section 20.2.50.123 NMAC that are applicable to tank batteries; or

(b) submit a VOC minimization plan to the department demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel. The plan shall state the good operational or engineering practices used to minimize VOC emissions. The plan shall be enforceable by the department upon submission. The department may require revisions to the plan, and must approve any proposed revisions to the plan.

Subsection B of Section 20.2.50.126 sets forth emission standards for PWMUs. Paragraph (1) requires owners and operators to employ best management and good engineering practices to minimize emissions of VOC from produced water management units. Paragraph (2) prohibiting owners from transferring untreated produced water to a PWMU without first processing and treating it to remove entrained hydrocarbons. NMED made significant revisions to this Subsection based on comments from NMOGA and CDG, as detailed in NMED Rebuttal Exhibit 1, p. 100.

The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, p. 154-56, and NMED Rebuttal Exhibit 1, p. 100.

The Department is also proposing a new Paragraph (3) of this Subsection addressing storage vessels associated with PWMUs. Owners and operators are required to either control such storage vessels in accordance with the requirements of Section 20.2.50.123 that are applicable to tank batteries, or submit a VOC minimization plan to the Department demonstrating that controlling VOC emissions in accordance with Section 20.2.50.123 is technically infeasible, and identifying good operational or engineering practices that will be used to minimize VOC emissions. These changes were addressed at the hearing. *See* Tr. Vol. 9, 3177:14-18, 3178:7-16. The Board adopts this proposal for the reasons stated at the hearing, as supported by CDG, and as supported by NMOGA with regard to Paragraphs (2) and (3).

CDG supported the addition of a provision regarding technical infeasibility without supplemental fuel, *see* CDG NOI Direct Testimony - Il Kim, pgs. 3-4, CDG Attachment D - Streams with High Moisture Content, CDG Attachment E - Cost Estimate of the Economic Impacts, and Hearing Transcript - Il Kim, Volume 9, pg. 2935, line 20 through pg. 2936, line 16. Acceptance of concept by NMED: Transcript -Elizabeth Bisbey-Kuehn, Volume 9, pg. 3033, line 12 through pg. 3034, line 6.]

CDG provides services for disposal of produced water at underground injection well facilities and recycling of produced water at produced water management unit (PWMU) facilities. Millions of barrels of produced water are recycled each year at PWMUs and returned to oil and gas producers for use in hydraulic fracturing and other reuse operations in lieu of using fresh water. These recycle ponds are several acres in size and often have the capacity to contain several hundred thousand barrels of water. A common and successful approach to minimizing emissions from

PWMUs is to implement good operational and engineering practices through the reduction of hydrocarbons in the water prior to entering the pond. The water sent to these PWMUs goes through good operational and engineering practices to reduce emissions.

NMED's proposal recognizes these distinctions and is drafted to achieve the legislative purpose to protect and enhance the environment and water conservation while enabling Group members to responsibly conduct their businesses in compliance with the rule's provisions. The goal of reducing ozone emissions is achieved, while preserving the continued utilization of produced water recycling, reuse, and treatment operations so important to New Mexico's efforts to safeguard its valuable water resources. The proposal encourages further responsible investment in and operation of critical water recycling, reuse, and treatment operations in New Mexico. [CDG NOI Direct Testimony: Il Kim, pgs. 3-4; Jill Cooper, pgs. 4-6; Ashley Campsie, pgs. 5-6; Exhibit CDG 4 - Streams with High Moisture Content; Exhibit CDG 5 - Cost Estimate of the Economic Impacts; Hearing Transcript, Volume 9, 2935:20 – 2936:16; 3033:12 – 3034:6.].

Generally, the produced water received by the Group has been processed by the producers prior to its receipt and is then typically further processed by the members of the Group. This water is therefore considered "post-flash" water that characteristically contains very low levels of VOCs. In some situations, emission reductions are technically infeasible without the use of supplemental fuel for combustion of vapors. In these situations, sites with very low hydrocarbon concentrations in the vapors could end up increasing total emissions of not only VOCs, but NOx and carbon monoxide as well, due to the use of supplemental fuel for combustion. To avoid these unintended and harmful results, the Proposed Rule provides a process for a PWMU operator to submit a VOC minimization plan to NMED demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel.

This option assures that the rules' requirements, which apply to the commercial produced water recycling and disposal industry, are technically feasible and cost effective with commensurate environmental benefit. [CDG NOI Direct Testimony: Il Kim, pgs. 3-4, 8; Jill Cooper, pgs. 4-6; Ashley Campsie, pgs. 5-6; Exhibit CDG 4 - Streams with High Moisture Content; Exhibit CDG 5 - Cost Estimate of the Economic Impacts; Hearing Transcript, Volume 9, 2935:20 – 2936:16; 3033:12 – 3034:6.]

NMOGA supported paragraph (3) contingent on its proposal that "recycling facility" be excluded from the definition of produced water management units. The Board rejects this proposal for lack of justification in the record.

C. Monitoring requirements: The owner or operator shall:

(1) develop a protocol to calculate the VOC emissions from each PWMU. The protocol shall include at a minimum: produced water throughput monitoring, semi-annual sampling and analysis of the liquid composition, hydrocarbon measurement method(s), representative sample size, and sample chain of custody requirements.

(2) calculate the monthly total VOC emissions in tons from each unit with the first month of emission calculations beginning within 180 days of the effective date of this Part;

(3) monthly, monitor the best management and good operational or engineering practices implemented to reduce emissions at each unit to ensure and demonstrate their effectiveness;

(4) upon written request by the department, sample the PWMU to determine the VOC content of the liquid; and

(5) comply with the monitoring requirements of 20.2.50.112 NMAC.

Subsection C of Section 20.2.50.126 sets forth monitoring requirements for PWMUs. Paragraph (1) requires owners and operators to develop a protocol to calculate VOCs from each PWMU and specifies minimum requirements for such protocols. Paragraph (2) requires calculation of monthly total VOC emissions from each unit beginning within 180 days of the effective date of Part 50. Paragraph (3) requires monthly monitoring of best management and operational practices used to reduce emissions at each unit, and demonstration of their effectiveness. Paragraph (4) allows the department to require an owner or operator to sample a PWMU to determine the VOC content of the liquid. NMED made numerous revisions to its original proposal in this Subsection based on comments from CDG and NMOGA, as detailed in NMED Rebuttal Exhibit 1, pp. 100-102. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 154-56; NMED Rebuttal Exhibit 1, pp. 100-102.

The Board adopts CDG's proposal to insert the word "sample" in front of the words "chain of custody requirements" for clarification purposes, and as supported by NMOGA.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each PWMU:

(a) unique identification number and UTM coordinates of the PWMU;

(b) the good operational or engineering practices used to minimize emissions of VOC from the PWMU;

(c) the VOC emissions calculation protocol required in Subsection C of 20.2.50.126 NMAC, including the results of the sampling conducted in accordance with the protocol; and

(d) the annual total VOC emissions from each PWMU.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Subsection D of Section 20.2.50.126 specifies recordkeeping requirements for PWMUs. Owners and operators are required to maintain records for each produced water unit including its name or identification number; UTM coordinates; description of good operational and engineering practices used to minimize VOC releases; records relating to the monitoring protocol in Subsection C, including results of sampling conducted in accordance with the protocol and a record of the annual total VOC emissions. NMED made revisions to its original proposal in this Subsection based on comments from CDG, as detailed in NMED Rebuttal Ex. 1, p. 102. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 154-56; NMED Rebuttal Exhibit 1, pp. 100-102.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.126 NMAC - N, XX/XX/2021]

Subsection E of Section 20.2.50.121 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 152-155.

Estimated Costs and Emissions Reductions from Section 20.2.50.126

Section 20.2.50.126 specifies that best management practices and good engineering practices must be used to minimize VOC emissions at PWMUs, but does not require the use of emission control devices. It is expected that these practices will require personnel to manage the minimization of emissions PWMUs, but no capital costs are anticipated. Costs associated with best management and good engineering practices are expected to be minimal as personnel will already be onsite at the facility, and any additional training may be incorporated into existing personnel training programs. PWMUs are unregulated under the federal Clean Air Act and its implementing regulations, and EPA has not published emission factors specific to this type of operation. NMED Ex. 32, pp. 155-56.

The Board finds that the costs associated with Section 20.2.50.126 are reasonable, and the requirements of Section 20.2.50.126 help achieve important emissions reductions while continuing to encourage the use of produced water instead of freshwater resources throughout the industry.

20.2.50.127 FLOWBACK VESSELS AND PREPRODUCTION OPERATIONS
A. Applicability: Wells undergoing recompletions and new wells being completed at an existing wellhead site are subject to the requirements of 20.2.50.127 NMAC one year after the effective date of this Part. New wells constructed at a new wellhead site that commence completion or recompletion on or after the effective date of this Part are subject to the requirements of 20.2.50.127 NMAC.
B. Emissions standards:

(1) The owner or operator of a well that begins flowback on or after the effective date of this Part 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 an operating control device that achieves a hydrocarbon control efficiency of at least ninety-five percent. If a TO or ECD is used, it must have a design destruction efficiency of at least ninety-eight percent for hydrocarbons.

(2) The owner or operator shall ensure that a control device used to comply with the emission standards in 20.2.50.127 NMAC operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(3) Flowback vessels shall be inspected, tested, and refurbished where necessary to ensure the flowback vessel is in compliance with Paragraph (2) of Subsection B of 20.2.50.127 NMAC prior to receiving flowback.

(4) The owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(5) Thief hatches or other access points to the flowback vessel(s) must remain closed and latched during activities to determine the quantity of liquids in the flowback.

(6) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system, or to add biocides or chemicals, is not a violation of Paragraph 2 of Subsection B of 20.2.50.127 NMAC.

C. Monitoring requirements: The owner or operator of a well with flowback that begins on or after the effective date of this Part shall conduct daily visual inspections of the flowback vessel and any associated equipment. Such inspections shall include:

(1) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated;

(2) visual inspection or monitoring of the control device to ensure that it is operating; and

(3) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

D. Recordkeeping requirements:

(1) The owner or operator of each flowback vessel subject to the emissions standards in Subsection B of 20.2.50.127 NMAC shall maintain the following records:

(a) the API number of the well and the associated facility location, including latitude and longitude coordinates;

(b) the date and time of the onset of flowback;

(c) the date and time that the flowback vessels were permanently disconnected, if applicable;

(d) the date and duration of any period where the control device was not operating; and

(e) records of the inspections required in Subsection C of 20.2.50.127 NMAC, including the following:

(i) time and date of each inspection;

(ii) a description of any problems observed;

(iii) a description of any corrective action(s) taken; and

(iv) the name and position of the person performing the corrective action(s).

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

As part of their direct testimony, CEP submitted a joint proposal to move the Department's proposed language in Section 20.2.50.127 to a new Section 20.2.50.128, and include new substantive requirements for flowback vessels and preproduction operations in Section 20.2.50.127, as well as additional definitions in Section 20.2.50.7 NMAC for the terms “Drilling” or “drilled”; “Drill-out”; “Flowback”; “Flowback vessel”; “Hydraulic fracturing”; “Hydraulic refracturing”; and “Pre-production operations”. *See* CEP Joint Proposed Amendments – July 28, 2021.

As part of the rebuttal testimony submissions, Oxy USA and the CEP came together with a joint proposal on this new Section 20.2.50.127, including the associated definitions listed above. *See* CEP and Oxy USA Joint Proposed Amendments – September 7, 2021. The Department did not take a position on this proposal, citing lack of expertise, and recommended the Board decide the issue based on testimony of the other parties. Tr. Vol. 10, 3380:24 – 3381:9. The Board adopts the proposal for the reasons that follow, based on the substantial evidence discussed.

The CEP and Oxy support the completions/recompletions proposal above. The completions/recompletions proposal requires operators to route initial flowback to enclosed, controlled flowback vessels during completion and recompletion of wells to reduce emissions during initial flowback. This would reduce emissions during completions and recompletions of wells by requiring operators to route initial flowback to enclosed, controlled flowback vessels during completion and recompletion of wells. *See* CEP Ex. 1 at 35-36. The CEP and Oxy’s proposed, at 20.2.50.127 NMAC, is modeled after rules adopted in 2020 by the Colorado Air Quality Control Commission and the Colorado Oil and Gas Conservation Commission (COGCC”) with one significant change. The CEP and Oxy’s completions/recompletions proposal deletes Colorado language requiring flowback vessels to be “vapor tight.” This change was made to ensure that operators install a pressure relief system to prevent dangerous static buildup and discharge. 10 Tr. 3232:16-3233:5 [Alexander Test.]; 10 Tr. 3307:1-6 [Holderman Test.].

Implementation of the proposal is safe: EDF witness Tom Alexander and Oxy witness Danny Holderman testified in support of this proposal. Both Mr. Alexander and Mr. Holderman, an engineer, have expertise in completions; both managed completions for major oil and gas companies. Flowback tanks are used during oil and gas pre-production activities and can lead to uncontrolled VOC and methane emissions if the tanks are not designed to contain these vapors. EDF Ex. EE at 23 [CDPHE Cost-Benefit Analysis for Regulation 7]. The VOC and methane emissions from completions/ recompletions are not insignificant. *See* EDF Ex. EE at 26-27, Tables 12 & 13.

Mr. Alexander explained to the EIB how, under the proposal, emissions from "initial flowback" would be routed to flowback vessels. He explained how the flowback vessels have a pressure relief system to accommodate any safety issues that could arise from significant changes in pressure or flow rates. Any emissions from a pressure relief system must be routed to a flare equipped with an auto-ignitor or continuous pilot light to minimize venting and emissions during completions/recompletions. EDF Ex. UU at 12.

Both Mr. Alexander, who was Vice President of Health, Safety and Environment at a major oil and gas company, and Mr. Holderman testified that implementation of the proposal is safe. Indeed, operators in Colorado have not raised any concerns with implementing the completions/recompletions requirements with CDPHE.

NMOGA's only objection that the proposal is unsafe is based on a mischaracterization of the terms of the proposal. NMOGA's only real objection to the completions/recompletions proposal came from Mr. Smitherman who mischaracterized the proposal as requiring "vapor tight" vessels. Mr. Smitherman incorrectly characterized the proposal even though he admitted during cross-examination that he was aware that the "vapor tight" language had been removed because of safety concerns. 10 Tr. 3352:9-18. Mr. Smitherman's concern had to do with the "static buildup" that could occur during initial flowback with a "vapor tight" vessel. 10 Tr. 3322:3-14. However, as Mr. Holderman explained: "First, Oxy USA removed the vapor tight reference [from EDF and Clean Air Advocates' original proposal] because it could be read to exclude pressure relief systems which are an essential safety feature for control systems. The general control language Oxy USA has proposed would not restrict pressure relief systems and is more consistent with safe operation." 10 Tr. 3307:1-6.

Mr. Smitherman provided no testimony why the CEP and Oxy's proposal, removing the vapor tight language, is problematic from a safety standpoint. Therefore, there is no evidence in the record why implementation of the completions/recompletions proposal would be unsafe. There is substantial evidence in the record from Mr. Holderman, an engineer with specialized knowledge of completions, and Mr. Alexander, a former safety director with specialized knowledge of completions, that the requirements for reducing emissions from completions and recompletions from the proposal are safe. Moreover, both Colorado's air pollution agency and its oil and gas agency have adopted similar rules, after hearing, and the CDPHE report no operator complaints or issues with the requirements.

There is substantial evidence in the record that the completions/recompletions proposal is cost effective, and no evidence in the record to the contrary. Based on CDPHE's September 2020 detailed cost-benefit analysis for its flowback vessel rule, EDF environmental engineer Hillary Hull calculated the cost for the Community and Environmental Parties and Oxy's completions/recompletions proposal would be $259.48 per ton of VOC reduced, which is cost effective according to Ms. Hull. EDF Ex. SS at 15; EDF Ex. UU at 14; 10 Tr. 3283:1-10. When Mr. Alexander was a Completions Manager, his company was completing 400 to 500 horizontal wells a year. According to Mr. Alexander "we understood the costs" of completions and, in his expert opinion, the CEP and Oxy's completions/recompletions proposal is cost effective and the costs "are very, very reasonable." 10 Tr. 3229:6-3230:17; EDF Ex. UU at 13-14. No industry party presented a cost-benefit analysis for the Community and Environmental Parties and Oxy's completions/recompletions proposal or rebutted EDF's cost-benefit calculations.

The completions/recompletions proposal fills a regulatory gap. Neither the U.S. Environmental Protection Agency nor the New Mexico Oil Conservation Commission requires flowback to be routed to enclosed, controlled flowback vessels during initial flowback. 10 Tr. 3233:7-3234:6; -3234:13-21. The CEP and Oxy's completions/ recompletions proposal fills "a gap" in those rules, will reduce VOC and methane emissions during the initial flowback stage, and will strengthen the EIB's final rule. 10 Tr. 3234:3-6.

Uncontrolled emissions during completions and recompletions have real life impacts on persons living in close proximity to oil and gas development. Don Schreiber has lived in close proximity to oil and gas development for over two decades. There are about 122 gas wells on or around his ranch, including 33 wells within one mile of his home. He has firsthand experience with the impacts of oil and gas development and with the impacts of completions and recompletions of wells, which are a particular concern for him. CAA Ex. 10 at 2-3 [Schreiber Dir. Test.]. In the early 2000's, well completions were still being done essentially the same way as they had been for over 50 years in the San Juan Basin. CAA Ex. 10 at 2-3. The environmental impacts of blewie line completions were obvious to Mr. Schreiber and his family -- given all the audio, visual and olfactory evidence -- as they lived and worked around their ranch. The impacts came into especially sharp focus when one time as the flared gasses cooled, black "snowflakes" were created and drifted onto their home from a completion about 1¼ miles northeast of his ranch. CAA Ex. 10 at 2-3.

Moving away from outdated completions technology in order to avoid the harmful and toxic waste they created became a priority for Mr. Schreiber as ConocoPhillips planned to drill 44 wells in and around his ranch in 2008. At that time, Mr. Schreiber learned about "reduced emissions completions" or "RECs" that were already being done in the San Juan Basin and could help prevent the harmful emissions that he and his wife worried about. CAA Ex. 10 at 2-3. Mr. Schreiber worked with ConocoPhillips and BLM to develop a program for drilling the 44 wells that would reduce impacts to the land, water, and air. In September 2008, they reached agreement on the use of REC equipment, closed loop systems, well spacing, road construction, reclamation of surface damage, and other considerations that allowed the 44 well drilling program to begin in late 2008. Between 2008 and 2012, 22 of the 44 wells in the program were completed or recompleted consistent with his agreement with ConocoPhillips. In 2012, natural gas prices declined and the drilling program stopped. *Id.* at 6.

In August of 2017, Hilcorp Energy Company (Hilcorp) acquired ConocoPhillips' assets in the San Juan Basin, including all of the wells on and around the Schreibers' ranch. Since acquiring those assets, Hilcorp has refused to honor the agreement the Schreibers had with ConocoPhillips. Mr. Schreiber has witnessed Hilcorp completion operations in which flowback gasses are vented directly to the atmosphere, into the space where they live and work. CAA Ex. 10 at 7-8; CAA Ex. 18 [photographs of the Hilcorp operation with no REC equipment]. Mr. Schreiber strongly supports the CEP and Oxy's completions/ recompletions proposal. According to him:

> "There is now a gaping hole in New Mexico regulations that creates a serious issue that has plagued my family and other families who live, work, and go to school close to where oil and gas wells exist or may be drilled in the future. Standing on my ranch, I can see Colorado, less than 25 miles away. To know that the same operators that are allowed

> to vent ozone precursors, methane, and toxic pollutants from completions and recompletions in New Mexico are prohibited from doing so in Colorado is deeply troubling. These operators drill into the same formation. They vent pollutants into the same air shed. And they threaten communities in the same region of the country. If, unlike Colorado, New Mexico fails to adopt reduced emissions completion/recompletion requirements -- requirements that are technically feasible, reduce waste, and protect our public health and environment -- our state will have ignored, denied and discounted years of successful capture of emissions, verified by industry and its experts."
> CAA Ex. 10 at 9-10.

There is substantial evidence in the record that the CEP and Oxy's completions/recompletions proposal will reduce VOC and methane emissions, is cost effective, and poses no safety issues. There is no evidence in the record that the proposal is unreasonably costly or that the proposal, as drafted excluding the "vapor tight" language and allowing for a pressure relief system, poses safety risks. Based on the testimony and evidence of the parties, the Boars adopts the CEP and Oxy's completions/recompletions proposal.

In summary, the proposal is beneficial because:

- There are substantial uncontrolled emissions during initial flowback. EDF Ex. EE at 26-27, Tables 12 & 13.
- The proposal is modeled after rules adopted in 2020 by the Colorado Air Pollution Control Commission and the Colorado Oil and Gas Conservation Commission with one significant change, deleting language requiring flowback vessels to be "vapor tight." This change was made to ensure that operators install a pressure relief system to prevent dangerous static buildup and discharge. 10 Tr. 3232:16-3233:5; 10 Tr. 3307:1-6.
- EDF witness Tom Alexander and Oxy witness Danny Holderman, an engineer, have managed completions for major oil and gas companies and testified in support

of the proposal and that implementation would be safe. 10 Tr. 3232:3-3234:5, -3232:22-3233:5; -3307:1-6.

- NMOGA's witness John Smitherman attempted to rebut Mr. Alexander and Mr. Holderman's testimony, but his testimony was based on his incorrect characterization that the proposal requires vessels to be "vapor tight" and he gave no testimony that the actual proposal, which allows for a pressure relief system, would be unsafe. 10 Tr. 3319:25-3320:3321:6.
- EDF analyzed the costs to implement the proposal using a cost-benefit analysis from the Colorado Department of Public Health and the Environment and New Mexico specific data, and found the proposal to be a cost-effective means of mitigating flowback, EDF Ex. SS at 15; EDF Ex. UU at 14; 10 Tr. 3283:1-10, as did Mr. Alexander who found the costs "are very, very reasonable." EDF Ex. UU at 13-14; 10 Tr. 3229:14-3230:17.

20.2.50.128 PROHIBITED ACTIVITY AND CREDIBLE EVIDENCE

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible evidence or information obtained by the department or provided to the department by a third party indicates that a source is not in compliance with the provisions of this Part that evidence or information may be used by the department for purposes of establishing whether a person has violated or is in violation of this Part.

Section 20.2.50.128 contains provisions regarding enforcement for violations of Part 50. Subsection A expressly states what is implicit in any mandatory requirement of an air quality regulation under the CAA or the AQCA: that failure to comply with any of the requirements in Part 50 within the specified timeframes constitutes a violation of Part 50 that is subject to enforcement action under the AQCA. This Section provides clear notice to the regulated community that failure to comply with the provisions of Part 50 will be subject to enforcement.

Subsection B provides that the Department may use credible evidence or information obtained by the Department or provided to the Department by a third party to establish a violation under Part 50.

The Department worked with NMOGA, Oxy USA, Clean Air Advocates, and EDF to come up with the current proposed language for Section 20.2.50.127, and all the Parties stipulated to this language. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 157-58; NMED Rebuttal Exhibit 1, p. 103; and Bisbey-Kuehn Testimony, Tr. 6:1979:23-25 – 1982:1:20, as supported by NMOGA.

HISTORY OF 20.2.50 NMAC: [**RESERVED**]

V. CONCLUSION

In making these rules, the Board gave weight to all facts and circumstances, including: the character and degree of injury or interference with health, welfare, visibility and property; the public interest including the social and economic value of the sources and subjects of air contaminants; and the technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved and previous experience with equipment and methods available to control the air contaminants involved. The Board finds that these factors weigh in favor of adoption of Part 50, as provided herein.

FINAL ORDER

For all of the reasons stated above, the Environmental Improvement Board hereby adopts the new rule 20.2.50 NMAC attached to this order as *Attachment 1*.

Phoebe K. Suina Digitally signed by Phoebe K. Suina
Date: 2022.06.26 14:33:18 -06'00'

6/26/2022

Phoebe Suina, Chair
Environmental Improvement Board

Date

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

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2022]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. As of the effective date, sources located in the following counties of the state are subject to this Part: Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia.

A. If, at any time after the effective date of this Part, sources in any other area(s) of the state not previously specified are determined to be causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated by the U.S. Environmental Protection Agency based on data from one or more department monitors, the department shall petition the Board to amend this Part to incorporate the sources in those areas.

(1) The notice of proposed rulemaking shall be published no less than one-hundred and eighty (180) days before sources in the affected areas will become subject to this Part, and shall include, in addition to the requirements of the Board's rulemaking procedures at 20.1.1.301 NMAC:

(a) a list of the areas that the department proposed to incorporate into this Part, and the date upon which the sources in those areas will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for throughout this Part, for sources within the areas subject to the proposed rulemaking to come into compliance with the provisions of this Part.

(2) In any rulemaking pursuant to this Section, the Board shall be limited to consideration of only those proposed changes necessary to incorporate other areas of the state into this Part.

B. Once a source becomes subject to this Part based upon its potential to emit, all requirements of this Part that apply to the source are irrevocably effective unless the source obtains a federally enforceable limit on the potential to emit that is below the applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.
[20.2.50.2 NMAC – N, XX/XX/2022]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2022]

20.2.50.5 EFFECTIVE DATE: Month XX, 2022, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, compression, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2022]

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.

A. **"Auto-igniter"** means a device that automatically attempts to relight the pilot flame of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

ATTACHMENT 1

B. **"Bleed rate"** means the rate in standard cubic feet per hour at which gas is continuously vented from a pneumatic controller.

C. **"Calendar year"** means a year beginning January 1 and ending December 31.

D. **"Centrifugal compressor"** means a 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 a mechanical rotating vane or impeller. A screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

E. **"Closed vent system"** means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere during operation.

F. **"Commencement of operation"** means for an oil and natural gas well site, the date any permanent production equipment is in use and product is consistently flowing to a sales line, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

G. **"Component"** means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water, or methanol.

H. **"Connector"** means flanged, screwed, or other joined fittings used to connect pipeline segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipeline to a piece of equipment; or an instrument to a pipe, tube, or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

I. **"Construction"** means fabrication, erection, or installation of a stationary source, including but not limited to temporary installations and portable stationary sources, but does not include relocations or like-kind replacements of existing equipment.

J. **"Control device"** means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices may include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part. A VRU or other equipment used primarily as process equipment is not considered a control device.

K. **"Department"** means the New Mexico environment department.

L. **"Design value"** means the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

M. **"Downtime"** means the period of time when equipment is not in operation.

N. **"Drilling" or "drilled"** means the process to bore a hole to create a well for oil and natural gas production.

O. **"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 cleanup.

P. **"Enclosed combustion device"** means a combustion device where waste gas is combusted in an enclosed chamber solely for the purpose of destruction. This may include, but is not limited to, an enclosed flare or combustor.

Q. **"Existing"** means constructed or reconstructed before the effective date of this Part.

R. **"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.

S. **"Flowback vessel"** means a vessel that contains flowback.

T. **"Gathering and boosting station"** means a facility, including all equipment and compressors, located downstream of a well site that collects or moves natural gas prior to the inlet of a natural gas processing plant; or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation. Gathering and boosting stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

U. **"Glycol dehydrator"** means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

V. **"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.

W. **"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 requires flowback to expel fracture fluids and solids.

X. **"Hydraulic refracturing"** means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Y. **"Hydrocarbon liquid"** means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.

Z. **"Inactive well site"** means a well site where the well is not being used for beneficial purposes, such as production or monitoring, and is not being drilled, completed, repaired or worked over.

AA. **"Injection well site"** means a well site where the well is used for the injection of air, gas, water or other fluids into an underground stratum.

BB. **"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 above de minimis amounts to the atmosphere as part of the actuation cycle.

CC. **"Liquid unloading"** means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

DD. **"Liquid transfer"** means the unloading of a hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport.

EE. **"Local distribution company custody transfer station"** means a metering station where the local distribution company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the local distribution company's intrastate transmission or distribution lines.

FF. **"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.

GG. **"Natural gas-fired heater"** means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

HH. **"Natural gas processing plant"** means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, 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.

II. **"New"** means constructed or reconstructed on or after the effective date of this Part.

JJ. **"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 instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.

KK. **"Occupied area"** means the following:

(1) a building or structure used as a place of residence by a person, family, or families, and includes manufactured, mobile, and modular homes, except to the extent that 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 similar place of outdoor public assembly.

LL. **"Operator"** means the person or persons responsible for the overall operation of a stationary source.

MM. **"Optical gas imaging (OGI)"** means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

NN. **"Owner"** means the person or persons who own a stationary source or part of a stationary source.

OO. **"Permanent pit or pond"** means a pit or pond used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

PP. **"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) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

QQ. **"Pneumatic diaphragm pump"** means a positive displacement pump powered by pressurized 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.

RR. **"Potential to emit (PTE)"** means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions 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.

SS. **"Pre-production operations"** means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil or natural gas well.

TT. **"Produced water"** means a liquid that is an incidental byproduct from well completion and the production of oil and gas.

UU. **"Produced water management unit"** means a recycling facility or a permanent pit or pond that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

VV. **"Qualified Professional Engineer"** means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

WW. **"Reciprocating compressor"** means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

XX. **"Reconstruction"** means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

YY. **"Recycling facility"** means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

ZZ. **"Responsible official"** means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

AAA. **"Routed pneumatic controller"** means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.

BBB. **"Small business facility"** means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited-service workers.

CCC. **"Stabilized"** means, when used to refer to stored condensate, that the condensate has 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."

DDD. **"Standalone tank battery"** means a tank battery that is not designated as associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station.

EEE. **"Startup"** means the setting into operation of air pollution control equipment or process equipment.

FFF. **"Stationary source"** or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

GGG. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck or railcar; a process vessel such as a surge control vessel, bottom receiver, or knockout vessel; a pressure vessel designed to operate in excess of 204.9 kilopascals (29.72 psi) without emissions to the atmosphere; or a floating roof tank complying with 40 CFR Part 60, Subpart Kb.

HHH. "Tank battery" means a storage vessel or group of storage vessels that receive or store crude oil, condensate, or produced water from a well or wells for storage. The owner or operator shall designate whether a tank battery is a standalone tank battery or is associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station. The owner or operator shall maintain records of this designation and make them available to the department upon request. A tank battery associated with a well site, gathering or boosting station, natural gas processing plant, or transmission compressor station is subject to the requirements in this Part for those facilities, as applicable. Tank battery does not include storage vessels at saltwater disposal facilities or produced water management units.

III. "Temporarily abandoned well site" means an inactive well site where the well's completion interval has been isolated. The completion interval is the reservoir interval that is open to the borehole and is isolated when tubing and artificial equipment has been removed and a bottom plug has been set.

JJJ. "Transmission compressor station" means a facility, including all equipment and compressors, that moves pipeline quality natural gas at increased pressure from a well site or natural gas processing plant through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, underground storage, or to other industrial end users. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

KKK. "Vessel measurement system" means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

LLL. "Wellhead only facility" means a well site that does not contain any production or processing equipment other than artificial lift natural gas driven pneumatic controllers and emergency shutdown device natural gas driven pneumatic controllers.

MMM. "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

NNN. "Well site" means the equipment under the operator's control directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant or gathering and boosting station, if any. A well site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. A well site does not include an injection well site.

[20.2.50.7 NMAC - N, XX/XX/2022]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2022]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2022]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2022]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations,

including more stringent controls.
[20.2.50.11 NMAC - N, XX/XX/2022]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2022]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [**RESERVED**]

20.2.50.111 APPLICABILITY:

A. This Part applies to certain crude oil and natural gas production and processing equipment associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer or an inhouse engineer with expertise in the operation of oil and gas equipment, vapor control systems, and pressurized liquid samples. The emission standards and requirements of this Part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this Part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request. This certified calculation shall be completed before startup for new sources, and within two years of the effective date of this Part for existing sources.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil transmission pipelines, oil refineries, natural gas transmission pipelines (except transmission compressor stations), and saltwater disposal facilities are not subject to this Part.
[20.2.50.111 NMAC - N, XX/XX/2022]

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, or good engineering and maintenance practices. When used in this Part, the term manufacturer specifications means either the original equipment manufacturer (or successor) emissions-related design specifications, maintenance practices and schedules, or an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience. The owner or operator shall keep manufacturer specifications on file when available, as well as any alternative specifications that are being followed, and make them available upon request by the department. The terms of 20.2.50.112.A(1) apply any time reference to manufacturer specifications occurs in this Part.

(2) Sources, including associated air pollution control equipment and monitoring equipment, subject to emission standards or requirements under this Part shall at all times, including periods of startup, shutdown, and malfunction, be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions of VOC and NOx. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent consistent with safety and good air pollution control practices. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions beyond levels required by the applicable standard under this Part. The terms of 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.

(3) Within two years of the effective date of this Part, owners and operators of a source requiring equipment monitoring, testing, or inspection shall develop and implement a data system(s) capable of storing information for each source in a manner consistent with this Section. The owner or operator shall maintain information regarding each source requiring equipment monitoring, testing, or inspection in a data system(s), including the following information in addition to the required information specified in an applicable section of this Part:

(a) unique identification number;
(b) location (latitude and longitude) of the source;
(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);
(d) for each source, the controlled VOC (and NO_x, if applicable) emissions in lbs./hr. and tpy;
(e) make, model, and serial number; and
(f) a link to the manufacturer maintenance schedule or repair recommendations, or company-specific operational and maintenance practices.

(4) The data system(s) shall be maintained by the owner or operator of the facility.

(5) The owner or operator shall manage the source's record of data in the data system(s). The owner or operator shall generate a Compliance Database Report (CDR) from the information in the data system. The CDR is an electronic report maintained by the owner or operator and that can be submitted to the department upon request.

(6) The CDR is a report distinct from the owner or operator's data system(s). The department does not require access to the owner or operator's data system(s), only the CDR.

(7) The owner or operator's authorized representative must be able to access and input data in the data system(s) record for that source. That access is not required to be at any time from any location.

(8) The owner or operator shall contemporaneously track each monitoring event, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be uploaded into the data system as soon as practicable, but no later than three business days of each compliance event, and when the final reports are received;

(b) certain sections of this Part require a date and time stamp, including a GPS display of the location, for certain monitoring events. No later than one year from the effective date of this Part, the department shall finalize a list of approved technologies to comply with date and time stamp requirements, and shall post the approved list on its website. Owners and operators shall comply with this requirement using an approved technology no later than two years from the effective date of this Part. Prior to such time, owners and operators may comply with this requirement by making a written or electronic record of the date and time of any affected monitoring event; and

(c) data required by this Part shall be maintained in the data system(s) for at least five years.

(9) The department for good cause may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. Such requests may be made no more than once per year. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department. The owner or operator may request a hearing on whether good cause was demonstrated or whether the recommendations approved by the department must be implemented.

(10) Where Part 50 refers to applicable federal standards or requirements, the references are to the applicable federal standards or requirements that were in effect at the time of the effective date of this Part, unless the applicable federal standards or requirements have been superseded by more stringent federal standards or requirements.

(11) Prior to modifying an existing source, including but not limited to increasing a source's throughput or emissions, the owner or operator shall determine the applicability of this Part in accordance with 20.2.50.111.B NMAC.

B. Monitoring requirements: In addition to any monitoring requirements specified in the applicable sections of this Part, owners and operators shall comply with the following:

(1) Unless otherwise specified, the term monitoring as used in this Part includes, but is not limited to, monitoring, testing, or inspection requirements.

(2) If equipment is shut down at the time of periodic testing, monitoring, or inspection required under this Part, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

C. Recordkeeping requirements: In addition to any recordkeeping requirements specified in the applicable sections of this Part, owners and operators shall comply with the following:

(1) Within three business days of a monitoring event and when final reports are received, an electronic record shall be made of the monitoring event and shall include the information required by the applicable sections of this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years.

(3) By July 1 of each calendar year starting in 2024, the owner or operator shall generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of this Part at the time the CDR is prepared and keep this report on file for five years.

D. Reporting requirements: In addition to any reporting requirements specified in the applicable sections in this Part, the owner or operator shall respond within three business days to a request for information by the department under this Part. The response shall provide the requested information for each source subject to the request 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. If the department requests a CDR from multiple facilities, additional time will be given as appropriate.

[20.2.50.112 NMAC - N, XX/XX/2022]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC. Non-road engines as defined in 40 C.F.R. §§ 1068.30 are not subject to 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark ignition engine shall complete an inventory of all existing engines subject to this Part by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan (ACP) approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meet the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meet the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR EXISTING NATURAL GAS-FIRED SPARK IGNITION ENGINES

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
2 Stroke Lean Burn	>1,000	3.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	2.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	≥1,775 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich Burn	>1,000 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NEW NATURAL GAS-FIRED SPARK IGNITION ENGINES

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	> 500 and < 1875	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥ 1875	0.30 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to Part 50 by July 1, 2023, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(i) by January 1, 2024, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2026, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meet the emission standards.

(iii) by January 1, 2028, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meet the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable existing natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4,100	150	50	9

≥4,100 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each applicable new natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4,000	100	25	9
≥4,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

(10) In lieu of complying with the emission standards for individual engines and turbines established in Subsection B of 20.2.50.113 NMAC, an owner or operator may elect to comply with the emission standards through an Alternative Compliance Plan (ACP) approved by the department. An ACP must include the list of engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. Prior to submitting a proposed ACP to the Department, the owner or operator shall comply with the following requirements in the order listed:

(a) The owner or operator shall contract with an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the ACP proposal. The selected firm shall review the proposal to determine if it meets the requirements of this Part, and shall prepare and certify an evaluation of the proposed ACP indicting whether the ACP proposal adheres to the requirements of this Part.

(b) Following the independent third-party review, the owner or operator shall provide the ACP, along with the third-party evaluation and findings, to the department for posting on the department's website. The department shall post the ACP and the third-party review within 15 days of receipt.

(c) Following posting by the department, the owner or operator shall publish a notice in a newspaper of general circulation announcing the ACP proposal, the dates it will be available for review and comment by the public, and information on how and where to submit comments. The dates specified in the public notice must provide for a thirty-day comment period.

(d) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the ACP proposal and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(e) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the ACP proposal within 90 days. The department shall approve an ACP that meets the requirements of this Part, unless the department determines that the total allowable emissions under the ACP exceed the total allowable emissions under the emission standards of 20.2.50.113 NMAC. If approved by the department, the emission reductions and associated emission limits for the affected engines or turbines shall become enforceable terms under this Part.

(11) The owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. The owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B of 20.2.50.113 NMAC prior to submission of a request for alternative emissions standards under this Paragraph (11), provided that the owner or operator satisfies Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC, below. To qualify for an alternative emission standard, an owner or operator must comply with the following requirements:

(a) Prepare a reasonable demonstration detailing why it is not technically practicable or economically feasible for the individual engine or turbine to achieve the emissions standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, as applicable;

(b) Prepare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner;

(c) Prepare a technical analysis for the affected engine or turbine specifying the emission reductions that can be achieved through other means, such as combustion modifications or capacity limitations. The technical analysis shall include an analysis of any previous modifications of the source and a determination whether such modifications meet the definition of a reconstructed source, such that the source should be considered a new source under federal regulations. The analysis shall include a certification that the modifications to the source are not in violation of any state or federal air quality regulation; and

(d) Fulfill the requirements of Subparagraphs (a) through (c) of Paragraph (10) of Subsection B of 20.2.50.113 NMAC.

(e) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the alternative emission standards and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(f) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the alternative emission standards within 90 days. If approved by the department, the emission reductions and alternative emission standards for the affected engine or turbine shall become enforceable terms under this Part.

(g) If approved by the department, the emissions reductions and alternative standards for the affected engine or turbine shall become enforceable terms under this Part.

(12) A short-term replacement engine may be substituted for any engine subject to Section 20.2.50.113 NMAC consistent with any applicable air quality permit containing allowances for short term replacement engines, including but not limited to New Source Review and General Construction Permits issued under 20.2.72 NMAC. A short-term replacement engine is not considered a "new" engine for purposes of this Part unless the engine it replaces is a "new" engine within the meaning of this Part. The reinstallation of the existing engine following removal of the short-term replacement engine is not considered a "new" engine under this Part unless the engine was "new" prior to the temporary replacement.

C. Monitoring requirements:

(1) Maintenance and repair for a spark ignition engine, compression ignition engine, and stationary combustion turbine shall meet the manufacturer recommended maintenance schedule as defined in 20.2.50.112 NMAC.

(2) Maintenance conducted consistent with an applicable NSPS or NESHAP requirement shall be deemed to be in compliance with Paragraph (1) of Subsection (C) of 20.2.50.113 NMAC.

(3) Catalytic converters (oxidative, selective, and non-selective) and AFR controllers shall be inspected and maintained according to manufacturer specifications as defined in 20.2.50.112 NMAC, and shall include replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(4) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated within 180 days of the effective date applicable to the source as defined by Paragraphs (2) and (7) of Subsection B of this Section or, if installed more than 180 days after the effective date, within 60 days after achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup of such source. Compliance with the applicable emission standards shall be demonstrated by performing an initial emission test for NOx and VOC, as defined in 40 CFR 51.100(s) using U.S. EPA reference methods or ASTM D6348. Periodic monitoring shall be conducted annually to demonstrate compliance with the allowable emission standards and may be demonstrated utilizing a portable analyzer or EPA reference methods. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

If the manufacturer's rated BSFC is not available, an operator may use an alternative load calculation methodology based on available data.

(a) emissions testing shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(i) The results of emissions testing demonstrating compliance with the emission standard for CO may be used as a surrogate to demonstrate compliance with the emission standard for NMNEHC.

(5) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (4) of Subsection C of 20.2.50.113 NMAC.

(6) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall monitor the hours of operation by a non-resettable hour meter.

(7) An owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(8) Prior to any monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 and 113 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and unique identification number for the engine or turbine;

(b) location of the source (latitude and longitude);

(c) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule as defined in 20.2.50.112 NMAC; and

(d) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time stamp(s), including GPS of the location, of an inspection, maintenance, or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the person(s) conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine for a period of five years. The records shall include:

(a) make, model, and serial number for the tested engine or turbine;

(b) the date and time stamp(s), including GPS of the location, of any monitoring event, including sampling or measurements;

(c) date analyses were performed;

(d) name of the person(s) and the qualified entity that performed the analyses;

(e) analytical or test methods used;

(f) results of analyses or tests;

(g) calculated emissions of NOx and VOC in lb/hr and tpy; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine or turbine's actual hours of operation, to demonstrate that an equivalent allowable ton per year emission reduction as set forth in table 1 or table 3 of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC, or the ninety-five percent emission reduction requirement is met.

E. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.113 NM–C - N, XX/XX/2022]

20.2.50.114 **COMPRESSOR SEALS:**

A. **Applicability:**

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

B. **Emission standards:**

(1) The owner or operator of an existing centrifugal compressor with wet seals shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing, and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor with wet seals shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-five percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing and route them via a closed vent system to a control device, a recovery system, fuel cell, or a process stream.

(5) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates as designed and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location (latitude and longitude) of the centrifugal compressor;

(b) the date of construction or reconstruction of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the person(s) conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and unique identification number or equivalent identifier of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location (latitude and longitude) of the reciprocating compressor;

(b) the date of construction or reconstruction of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since the effective date, initial startup after the effective date, or the last rod packing replacement, as applicable;

(ii) data showing the effectiveness of the rod packing emissions collection system, as applicable; and

(iii) the time and date of the inspection, the person(s) conducting the inspection, a description of any problems observed during the inspection, and a description of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.114 NM–C - N, XX/XX/2022]

20.2.50.115 CONTROL DEVICES AND CLOSED VENT SYSTEMS:

A. Applicability: These requirements apply to control devices and closed vent systems as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle the reasonably expected range of inlet VOC or NOx concentrations or volumes.

(3) The owner or operator shall inspect control devices visually or consistent with applicable federally approved inspection methods at least monthly to identify defects, leaks, and releases, and to ensure proper operation. Prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(4) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, in order to minimize venting of unburnt gas to the atmosphere.

(5) The owner or operator of a permanent closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, natural gas driven pneumatic pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate the expected range of emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that emissions from the affected equipment are routed to the control device or process; and

(c) have the assessment certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of closed vent system(s) in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system assessment was prepared under my direction or supervision. I further certify that the closed vent system assessment was conducted, and this report was prepared, pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(d) an owner or operator of an existing closed vent system shall comply with the requirements of Paragraph (5) of Subsection B of 20.2.50.115 NMAC within three years of the effective date of this Part and within 90 days of startup for a new closed vent system.

(6) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include the unique identification number, type of unit, manufacturer name, make, model, capacity, and destruction or reduction efficiency data.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare, and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (c) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following no later than one year after the effective date of this part, unless otherwise specified:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream shall be equipped with a continuous pilot.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(e) the owner or operator shall repair the flare within three business days of any thermocouple or other flame detection device alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto-igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto-igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions;

(d) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of thermocouple, other approved technology, or flame detection device alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the most recent gas analysis for the gas being flared, including VOC content and heating value; and

(e) the date and time stamp(s), including GPS of the location, of any monitoring event.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new ECD/TO with a continuous pilot flame or an auto-igniter upon startup. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than two years after the effective date of this Part.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO. New ECD/TOs shall comply with this requirement upon startup, and existing ECD/TOs shall comply with this requirement within 2 years of the effective date of this Part.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto-igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto-igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(c) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the monitoring requirements of this Part.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of thermocouple, other approved technology, or flame detection device alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activities performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the date and time stamp(s), including GPS of the location, of any monitoring event; and

(d) the results of the most recent gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recovery units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime, unless otherwise approved in an air permit issued prior to the effective date of this Part. Alternatively, the owner or operator may shut down and isolate the source being controlled by the VRU. For sites that already have a VRU installed as of the effective date of this Part, the owner or operator shall install backup control devices or redundant VRUs within three years of the effective date of this Part.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the requirements of this Part.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event, including the name of the person(s) conducting the inspection, any maintenance or repair activities required, and the date and time stamp(s), including GPS of the location, of any monitoring event. The owner or operator shall record the type of redundant control device used during VRU downtime, or keep records of the source shut down and isolated and the time period during which it was shut down, or records of compliance with an air permit issued prior to the effective date of this Part.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: In addition to the general recordkeeping requirements of 20.2.50.112 NMAC, the owner or operator of a control device or closed vent system shall maintain a record of the following:

(1) the certification of the closed vent system assessment, where applicable, and as required by this Part; and

(2) the information required in Paragraph (6) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.115 NM–C - N, XX/XX/2022]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Well sites, tank batteries, gathering and boosting stations, natural gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Components in water or air service are not subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility-wide PTE and in determining the monitoring frequency requirements of this Section.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC. Tank batteries supporting multiple facilities are subject to the requirements for the most stringently regulated facility of which they are a part.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements:

(1) The owner or operator of a facility with an annual average daily production or average daily throughput of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct an external audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct an external visual inspection for defects, which may include cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors; and

(d) any positive detection during the AVO inspection shall be repaired in accordance with Subsection E if not repaired at the time of discovery.

(2) The owner or operator of a facility with an annual average daily production or average daily throughput of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an external audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as specified in Subparagraphs (a) through (d) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC; except that an owner or operator of a well site within 1,000 feet (as measured from the center of the well site to the applicable structure or area of public assembly) of an occupied area shall conduct the AVO inspection at least weekly.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules, and upon request by the department for good cause shown:

(a) for existing well sites and standalone tank batteries, the owner or operator shall comply with these requirements no later than two years from the effective date of this Part.

(b) for well sites and standalone tank batteries:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(c) for gathering and boosting stations and natural gas processing plants:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(d) for transmission compressor stations, quarterly or in compliance with the federal equipment leak and fugitive emissions monitoring requirements of New Source Performance Standards, 40 C.F.R. Part 60, as may be revised, so long as the federal equipment leak and fugitive emissions monitoring requirements are at least as stringent as the New Source Performance Standards OOOOa, 40 CFR Part 60, in existence as of the effective date of this Part.

(e) quarterly at well sites within 1,000 feet of an occupied area.

(f) for existing wellhead only facilities, annual inspections shall be completed on the following schedule: 30% by January 1, 2024; 65% by January 1, 2025; and 100% by January 1, 2026.

(g) for inactive well sites:

(i) for well sites that are inactive on or before the effective date of this Part, annually beginning within six months of the effective date of this Part;

(ii) for well sites that become inactive after the effective date of this Part, annually beginning 30 days after the site becomes an inactive well site.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of use by the procedures specified in U.S. EPA method 21 and the instrument manufacturer; and

(b) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbons, and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18; and

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface;

(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; and

(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.

(7) Owners and operators of well sites must conduct an evaluation to determine applicability of Subparagraph (e) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC within 30 days of constructing a new well site, and within 90 days of the effective date of this Part for existing well sites.

(8) An owner or operator conducting an evaluation pursuant to Paragraph (7) of Subsection C of Section 20.2.50.116 NMAC shall measure the distance from the latitude and longitude of each well at a well site to the following points for each type of occupied area:

(a) the property line for indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities and outdoor venues or recreation areas;

(b) the property line for outdoor venues or recreation areas, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly;

(c) the location of a building or structure used as a place of residency by a person, a family, or families; and

(d) the location of a commercial facility with five-thousand (5,000) or more square feet of building floor area that is operating and normally occupied during working hours.

(9) Injection well sites and temporarily abandoned well sites are not subject to the leak survey requirements of Paragraphs (3) through (6) of Subsection C of 20.2.50.116 NMAC.

(10) Prior to any monitoring event, the owner or operator shall date and time stamp the monitoring event.

D. Alternative equipment leak monitoring plans: An owner or operator may comply with the equipment leak requirements of Subsection C of 20.2.50.116 NMAC through an equally effective and enforceable alternative monitoring plan, which may include the use of alternative monitoring methods and technologies, as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to the department on an application form provided by the department. Within 90 days of receipt, the department shall issue a letter approving or denying the requested alternative monitoring plan. An owner or operator shall comply with the default monitoring requirements of Section 20.2.50.116 NMAC and may not operate under an alternative monitoring plan until it has been approved by the department.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements of Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved alternative monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department in writing of the intent to conduct monitoring under a pre-approved alternative monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting the first monitoring under that plan.

(b) the department may terminate the use of a pre-approved alternative monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of a pre-approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements of Subsection C of 20.2.50.116 NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component not otherwise repaired at the time of discovery until the component has been repaired;

(2) leaks shall be repaired as soon as practicable but no later than 30 days from discovery;

(3) the equipment must be re-monitored no later than 15 days after the repair of the leak to demonstrate that it has been repaired;

(4) if the leak cannot be repaired within 30 days of discovery without a process unit shutdown, the leak may be designated “Repair delayed,” the date of the next scheduled process unit shutdown must be identified, and the leak must be repaired before the end of the scheduled process unit shutdown or within 2 years, whichever is earlier; and

(5) if the leak cannot be repaired within 30 days of discovery due to shortage of parts, the leak may be designated “Repair delayed,” and must be repaired within 15 days of resolution of such shortage.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM 21, OGI, or alternative equipment leak monitoring inspections conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location (latitude and longitude);

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) monitoring method (e.g. AVO, RM 21, OGI, approved alternative method);

(d) name of the person(s) performing the inspection;
(e) a description of any leak requiring repair or a note that no leak was found; and
(f) whether a visible tag was placed on the leak.
(2) The owner or operator shall keep the following record for any leak that is detected:
(a) the date the leak is detected;
(b) the date of attempt to repair;
(c) for a leak with a designation of "repair delayed" the following shall be recorded:
(i) reason for delay if a leak is not repaired within the required number of days after discovery. If a delay is due to a parts shortage, a record documenting the attempt to order the parts and the unavailability due to a shortage is required;
(ii) the date of next scheduled process unit shutdown by which the repair will be completed; and
(iii) name of the person(s) who determined that the repair could not be implemented without a process unit shutdown.
(d) date of successful leak repair;
(e) date the leak was monitored after repair and the results of the monitoring; and
(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.
(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).
(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.
G. Reporting requirements:
(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.
(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.116 NMAC - N, XX/XX/2022]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:
A. Applicability: Liquid unloading operations resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Liquid unloading operations that do not result in the venting of any natural gas are not subject to this Part. Owners and operators of a natural gas well subject to this Part must comply with the standards set forth in Paragraph (1) of Subsection B of 20.2.50.117 NMAC within two years of the effective date of this Part.
B. Emission standards:
(1) The owner or operator of a natural gas well shall implement at least one of the following best management practices during the life of the well to avoid the need for venting of natural gas associated with liquid unloading:
(a) use of a plunger lift;
(b) use of artificial lift;
(c) use of a control device;
(d) use of an automated control system; or
(e) other practices if approved by the department.
(2) The owner or operator of a natural gas well shall implement the following best management practices during venting associated with liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:
(a) reduce wellhead pressure before blowdown or venting to atmosphere;
(b) monitor manual venting associated with liquid unloading in close proximity to the well or via remote telemetry; and
(c) close vents to the atmosphere and return the well to normal production operation as soon as practicable.
C. Monitoring requirements:
(1) The owner or operator shall monitor the following parameters during venting associated with liquid unloading:

(a) wellhead pressure;
(b) flow rate of the vented natural gas (to the extent feasible); and
(c) duration of venting to the storage vessel, tank battery, or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted during a venting event associated with a liquid unloading event.

(3) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:
(a) unique identification number and location (latitude and longitude) of the well;
(b) date of the unloading event;
(c) wellhead pressure;
(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the estimated flow rate in the emission calculation);
(e) duration of venting to the storage vessel, tank battery, or atmosphere;
(f) a description of the best management practices used to minimize venting of VOC emissions during the life of the well and before and during the liquid unloading; and
(g) a calculation of the VOC emissions vented during a liquid unloading event based on the duration, calculated volume, and composition of the produced gas.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.117 NMAC - N, XX/XX/2022]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) no later than two years after the effective date of this Part. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) the still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the VOC emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that reinjects the vapor into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent, which shall supersede any inconsistent requirements in 20.2.50.115 NMAC. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications; and

(c) the still vent and flash tank emissions shall not be vented directly to the atmosphere during normal operation.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy of VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) unique identification number and dehydrator location (latitude and longitude);

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and unique identification number of the control device or process the emissions are being routed;

(f) time and date stamp, including GPS of the location, of any monitoring;

(g) results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(h) a copy of the glycol dehydrator manufacturer specifications.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2022]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	400
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	400

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than three years after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly, if present;

(iv) optimizing total emissions of CO consistent with the NO_x requirement and manufacturer specifications, and good combustion practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_X or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load in a prior test plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(5) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) unique identification number and location (latitude and longitude) of the heater;

(2) summary of the complete test report and the results of periodic testing;

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date and time stamp, including GPS of the location, of the inspection, testing, maintenance, or repair conducted;

(b) name of the person(s) conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2022]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at existing well sites, standalone tank batteries, gathering and boosting stations with one or more controlled storage vessels, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC within two years of the effective date of this Part. Hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels are subject to the requirements of 20.2.50.120 NMAC on the schedule specified in Paragraph 1 of Subsection B of 20.2.50.123 NMAC. Hydrocarbon liquid transfers located at new well sites, standalone tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC upon startup. The following facilities and operations are not subject to the requirements of this Section:

(1) Any facility connected to an oil sales pipeline that is routinely used for hydrocarbon liquid transfers;

(2) Well sites, standalone tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations not connected to an oil sales pipeline that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year; and

(3) Transfers of hydrocarbon liquid from a transfer vessel to a storage vessel subject to the emission standards in 20.2.50.123 NMAC.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-five percent, when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker railcar for transport. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) An owner, operator, or personnel conducting the hydrocarbon liquid transfer using vapor balance shall:

(a) transfer the vapor displaced from the transfer truck or railcar being loaded back to the storage vessel being emptied via a pipe or hose connected before the start of the transfer operation. If multiple storage vessels are manifolded together in a tank battery, the vapor may be routed back to any storage vessel in the tank battery;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) inspect connector pipes, hoses, couplers, valves, and pressure relief devices for leaks;

(d) check the hydrocarbon liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Connector pipes and couplers shall be inspected and maintained to ensure there are no liquid leaks.

(4) Connections of hoses and pipes used during hydrocarbon liquid transfers shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(5) Liquid leaks that occur shall be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner, operator, or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations and semi-annually at unstaffed locations to ensure that hydrocarbon liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. At least once per calendar year, the inspection shall occur during a transfer operation. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation, or measures must be implemented to mitigate leaks until the necessary repairs are completed.

(2) The owner or operator of a hydrocarbon liquid transfer operation controlled by a control device must follow manufacturer specifications for the device.

(3) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(5) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the following:

(a) the location of the facility;

(b) if using a control device, the type, make, and model of the control device;

(c) the date and time stamp, including GPS of the location, of any inspection;

(d) the name of the person(s) conducting the inspection;

(e) a description of any problem observed during the inspection; and

(f) the results of the inspection and a description of any repair or corrective action taken.

(2) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.120 NMAC - N, XX/XX/2022]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Individual pipeline pig launcher and receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of affected pipeline pig launcher and receiver operations shall capture and reduce VOC emissions from pigging operations by at least ninety-five percent within two years of the effective date of this Part. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) The owner or operator conducting an affected pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to minimize emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to minimize emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that minimizes emissions to the atmosphere to the extent practicable; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to an individual pipeline pig launching and receiving operation if the actual annual VOC emissions of the launcher or receiver operation are less than one tpy of VOC.

(4) An owner or operator complying with Paragraphs (1) or (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of an affected pig launching and receiving site shall inspect the equipment for leaks using AVO, RM 21, or OGI on either:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

(b) prior to the commencement and after the conclusion of the pig launching or receiving operation, if less frequent.

(2) The monitoring shall be performed using the methodologies outlined in Subsection (C) of 20.2.50.116 NMAC as applicable and at the frequency required in Paragraph (1) of Subsection (C) of 20.2.50.121 NMAC. The monitoring shall be performed when the pig trap is under pressure.

(3) An owner or operator complying with Paragraphs (1) or (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements: In addition to complying with the recordkeeping requirements in 20.2.50.112 NMAC, the owner or operator of an affected pig launching and receiving site shall maintain a record of the following:

(1) the pigging operation, including the location, date, and time of the pigging operation;

(2) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE;

(3) date and time of any monitoring and the results of the monitoring; and

(4) the type of control device and its make and model.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2022]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An owner or operator shall ensure that its existing natural gas-driven pneumatic controllers comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

Table 1 – WELL SITES, STANDALONE TANK BATTERIES, GATHERING AND BOOSTING STATIONS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	85%	90%
> 60-75%	80%	85%	90%
> 40-60%	65%	70%	80%
> 20-40%	45%	70%	80%
0-20%	25%	65%	80%

Table 2 – TRANSMISSION COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	95%	98%
> 60-75%	80%	95%	98%

> 40-60%	65%	95%	98%
> 20-40%	50%	95%	98%
0-20%	35%	95%	98%

(4) Standards for natural gas-driven pneumatic controllers:

(a) new pneumatic controllers shall have an emission rate of zero. A natural gas driven pneumatic controller replacing an existing natural gas driven pneumatic controller at an existing facility is an existing pneumatic controller for purposes of Section 20.2.50.122 NMAC.

(b) owners and operators of existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by July 1, 2023, the owner or operator shall determine the total controller count for all controllers subject to each table separately at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count for each table must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count. This final number is the total historic controller count. Controllers identified as required for a safety or process purpose after July 1, 2023, shall not affect the total historic controller count.

(ii) determine which controllers in the total controller count for each table are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers for each table by dividing the total historic non-emitting controller count by the total historic controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above for each table, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers using the calculation methodology in Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC by January 1, 2025, for either or both table 1 or table 2, the owner or operator is not thereafter subject to the requirements of that table(s) of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(c) owners and operators of existing natural gas driven pneumatic controllers shall demonstrate compliance with tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, on January 1, 2024, January 1, 2027, and January 1, 2030, as follows:

(i) determine which controllers are emitting (excluding pneumatic controllers necessary for safety or process reasons pursuant to Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC) and sum the total number of emitting controllers for table 1 and table 2 facilities separately.

(ii) determine the percentage of non-emitting controllers by using the following equation for table 1 and table 2 facilities separately:

$$\text{Total Percentage of Non-Emitting Controllers} = 100 - ((\text{total emitting controllers} / \text{total historic controller count}) \times 100)$$

(iii) compliance is demonstrated if the Total Percentage of Non-Emitting Controllers calculated pursuant to Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC is less than or equal to the value for that year in the Total Historic Percentage of Non-Emitting Controllers row (as calculated pursuant to Subparagraph (b)(i)-(iv) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC) in table 1 or table 2, as applicable, of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(d) No later than January 1, 2024, a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller as excepted for process or safety reasons under Subparagraph (a)(i) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC must prepare and document the justification for the safety or process purpose prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional or inhouse engineer.

(e) Temporary pneumatic controllers that emit natural gas and are used for well abandonment activities or used prior to or through the end of flowback, and pneumatic controllers used as emergency shutdown devices located at a well site, are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(f) Temporary or portable pneumatic controllers that emit natural gas and are on-site for less than 90 days are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(5) Standards for natural gas-driven pneumatic diaphragm pumps:

(a) new pneumatic diaphragm pumps located at natural gas processing plants shall have an emission rate of zero.

(b) new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero within two years of the effective date of this Part.

(d) owners and operators of pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic diaphragm pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic diaphragm pump emissions to the control device within two years of the effective date of this Part.

C. Monitoring requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as a motive force are not subject to the monitoring requirements in Subsection C of 20.2.50.122 NMAC.

(2) No later than January 1, 2023, the owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller shall, on a monthly basis, conduct an AVO or OGI inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) Within two years of the effective date of this Part, the owner or operator’s data systems shall contain the following for each in-service natural gas-driven pneumatic controller:

(a) natural gas-driven pneumatic controller unique identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) if continuous, design annual bleed rate in standard cubic feet per year.

(5) Upon the effective date specified for the facility in 20.2.50.116 NMAC, the owner or operator of a natural gas-driven pneumatic diaphragm pump shall, on a monthly basis, conduct an AVO or OGI inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(6) The owner or operator of a natural gas-driven pneumatic controller shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC applicable to the facility type at which the pneumatic controller is installed on the effective date specified in 20.2.50.116 NMAC. During instrument inspections, operators shall use RM 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

(7) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(8) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Non-emitting pneumatic controllers and diaphragm pumps are not subject to the recordkeeping requirements in Subsection D of 20.2.50.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of natural gas-driven pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller. On or before January 1, 2024, January 1, 2027 and January 1, 2030, the owner or operator shall make and retain the compliance demonstration set forth in Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(5) The owner or operator shall maintain an electronic record for each natural gas-driven pneumatic controller. The record shall include the following:

(a) pneumatic controller unique identification number;

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) name of the person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) AVO or OGI level discrepancy in continuous or intermittent bleed rate;

(f) record of the controller type, bleed rate, or bleed volume required in Subparagraphs (b), (c), (d), and (e) of Paragraph (4) of Subsection C of 20.2.50.122 NMAC.

(g) maintenance date and maintenance activity; and

(h) a record of the justification and certification required in Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC. This demonstration shall be completed by July 1, 2023 for controllers with a bleed rate greater than six scf/hr and as necessary for controllers with a bleed rate less than or equal to six scf/hr.

(7) The owner or operator shall maintain a record for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic diaphragm pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified professional or inhouse engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2022]

20.2.50.123 STORAGE VESSELS

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels with a PTE equal to or greater than three tpy of VOC in multi-tank batteries, and existing storage vessels with a PTE equal to or greater than four tpy of VOC in single tank batteries are subject to the requirements of 20.2.50.123 NMAC. Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels. Storage vessels associated with produced water management units are required to comply with this Section to the extent specified in Subsection B of Section 20.2.50.126 NMAC.

B. Emission standards:

(1) An existing storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent according to the following schedule. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(a) By January 1, 2025, an owner or operator shall ensure at least 30% of the company's existing storage vessels are controlled;

(b) By January 1, 2027, an owner or operator shall ensure at least an additional 35% of the company's existing storage vessels are controlled; and

(c) By January 1, 2029, an owner or operator shall ensure the company's remaining existing storage vessels are controlled.

(2) A new storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the actual annual VOC emissions decrease to less than two tpy.

(4) If a control device is not installed by the date specified in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

(5) The owner or operator of a new or existing storage vessel with a thief hatch shall ensure that the thief hatch is capable of opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. Any pressure relief device installed must automatically close once the vessel overpressure is relieved.

(6) An owner or operator complying with Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

C. Storage vessel measurement requirements: Owners and operators of new storage vessels required to be controlled pursuant to this Part at well sites, tank batteries, gathering and boosting stations, or natural gas processing plants shall use a storage vessel measurement system to determine the quantity of liquids in the storage vessel(s). New tank batteries receiving an annual average of 200 bbls oil/day or more with available grid power shall be outfitted with a lease automated custody transfer (LACT) unit(s).

(1) The owner or operator shall keep thief hatches (or other access points to the vessel) and pressure relief devices on storage vessels closed and latched during activities to determine the quantity of liquids in the storage vessel(s), except as necessary for custody transfer. Tank batteries equipped with LACT units shall use the LACT unit measurements in lieu of field testing of quantity and quality except in case of malfunction. Nothing in this paragraph shall be construed to prohibit the opening of thief hatches, pressure relief devices, or any other openings or access points to perform maintenance or similar activities designed to ensure the safety or proper operation of the storage vessel(s) or related equipment or processes. Where opening a thief hatch is necessary, owners and operators of new and existing storage vessels shall minimize the time the thief hatch is open.

(2) The owner or operator may inspect, test, and calibrate the storage vessel measurement system either semiannually, or as directed by the Bureau of Land Management (see 43 C.F.R. Section 374.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening a thief hatch if required to inspect, test, or calibrate the vessel measurement system is not a violation of Paragraph (1) of this Subsection.

(3) The owner or operator shall install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(4) The owner or operator shall develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(5) The owner or operator must make and retain the following records for at least two years and make such records available to the department upon request:

(a) date of construction of the storage vessel or facility;

(b) description of the storage vessel measurement system used to comply with this

Subsection;

(c) date(s) of storage vessel measurement system inspections, testing, and calibrations that require opening the thief hatch pursuant to Paragraph (1) of this Subsection;

(d) manufacturer specifications regarding storage vessel measurement system inspections and calibrations, if followed pursuant to Paragraph (2) of this Subsection; and

(e) records of the annual training program, including the date and names of persons trained.

D. **Monitoring requirements:** No later than January 1, 2023, the owner or operator of a storage vessel shall:

(1) on a monthly basis, monitor, calculate, or estimate, the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig) if the storage vessel is directly downstream of a separator. When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the storage vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) prior to any monitoring event, date and time stamp the event and enter the monitoring data in accordance with the requirements of this Part;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements of 20.2.50.112 NMAC.

E. **Recordkeeping requirements:** No later than January 1, 2023, the owner or operator of a storage vessel shall comply with the following requirements:

(1) Monthly, maintain a record for each storage vessel of the following:

(a) unique identification number and location (latitude and longitude);

(b) monitored, calculated, or estimated monthly liquid throughput;

(c) the upstream separator pressure, if a separator is present;

(d) the data and methodology used to calculate the actual emissions of VOC (tpy);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) Verify each record of liquid throughput by dated liquid level measurements, a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) Make a record of the inspections required in Subsections C and D of 20.2.50.123 NMAC, including:

(a) the date and time stamp, including GPS of the location, of the inspection;

(b) the person(s) conducting the inspection;

(c) a description of any problem observed during the inspection; and

(d) a description and date of any corrective action taken.

(4) Comply with the recordkeeping requirements in 20.2.50.115 NMAC if complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

F. **Reporting requirements:**

(1) An owner or operator complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.115 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2022]

20.2.50.124 **WELL WORKOVERS**

A. **Applicability:** Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. **Emission standards:** The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering or operational practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the estimated volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements:**

(1) The owner or operator shall keep the following record for a workover:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the best management practices used to minimize release of VOC emissions before and during the workover;

(g) calculation of the estimated VOC emissions vented during the workover based on the duration, volume, and gas composition; and

(h) the method of notification to the public and proof that notification was made to the affected public.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements:

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail, or by other effective means of notice so long as the notification can be documented, all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

(3) If the workover is needed for routine or emergency downhole maintenance to restore production lost due to upsets or equipment malfunction, the owner or operator shall notify all residents located within one-quarter mile of the well of the planned workover at least 24 hours before the workover event.

[20.2.50.124 NMAC - N, XX/XX/2022]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to Sections 20.2.50.125 NMAC and 20.2.50.127 NMAC of this Part. Small business facilities are not subject to any other requirements of this Part unless specifically identified in 20.2.50.125 NMAC.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x

emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (9) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC. The owner or operator shall comply with Subsection B of 20.2.50.111 NMAC in determining applicability of the requirements in 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated annual VOC and NO_x emissions from each facility and the company-wide annual VOC and NO_x emissions for all subject facilities; and

(3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 of each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.

[20.2.50.125 NMAC - N, XX/XX/2022]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part and their associated storage vessels are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use good operational or engineering practices to minimize emissions of VOC from produced water management units (PWMU) and their associated storage vessels.

(2) The owner or operator shall not allow any transfer of untreated produced water to a PWMU without first processing and treating the produced water in a separator or storage vessel to minimize entrained hydrocarbons.

(3) Within two years of the effective date of this Part for storage vessels associated with existing PWMUs, or upon startup for storage vessels associated with new PWMUs, the owner or operator shall either:

(a) control such storage vessels in accordance with the requirements of Section 20.2.50.123 NMAC that are applicable to tank batteries; or

(b) submit a VOC minimization plan to the department demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel. The plan shall state the good operational or engineering practices used to minimize VOC emissions. The plan shall be enforceable by the department upon submission. The department may require revisions to the plan, and must approve any proposed revisions to the plan.

C. Monitoring requirements: The owner or operator shall:

(1) develop a protocol to calculate the VOC emissions from each PWMU. The protocol shall include at a minimum: produced water throughput monitoring, semi-annual sampling and analysis of the liquid composition, hydrocarbon measurement method(s), representative sample size, and sample chain of custody requirements.

(2) calculate the monthly total VOC emissions in tons from each unit with the first month of emission calculations beginning within 180 days of the effective date of this Part;

(3) monthly, monitor the best management and good operational or engineering practices implemented to reduce emissions at each unit to ensure and demonstrate their effectiveness;

(4) upon written request by the department, sample the PWMU to determine the VOC content of the liquid; and

(5) comply with the monitoring requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each PWMU:

(a) unique identification number and UTM coordinates of the PWMU;

(b) the good operational or engineering practices used to minimize emissions of VOC from the PWMU;

(c) the VOC emissions calculation protocol required in Subsection C of 20.2.50.126 NMAC, including the results of the sampling conducted in accordance with the protocol; and

(d) the annual total VOC emissions from each PWMU.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2022]

20.2.50.127 FLOWBACK VESSELS AND PREPRODUCTION OPERATIONS

A. Applicability: Wells undergoing recompletions and new wells being completed at an existing wellhead site are subject to the requirements of 20.2.50.127 NMAC one year after the effective date of this Part. New wells constructed at a new wellhead site that commence completion or recompletion on or after the effective date of this Part are subject to the requirements of 20.2.50.127 NMAC.

B. Emissions standards:

(1) The owner or operator of a well that begins flowback on or after the effective date of this Part 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 an operating control device that achieves a hydrocarbon control efficiency of at least ninety-five percent. If a TO or ECD is used, it must have a design destruction efficiency of at least ninety-eight percent for hydrocarbons.

(2) The owner or operator shall ensure that a control device used to comply with the emission standards in 20.2.50.127 NMAC operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(3) Flowback vessels shall be inspected, tested, and refurbished where necessary to ensure the flowback vessel is in compliance with Paragraph (2) of Subsection B of 20.2.50.127 NMAC prior to receiving flowback.

(4) The owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(5) Thief hatches or other access points to the flowback vessel(s) must remain closed and latched during activities to determine the quantity of liquids in the flowback.

(6) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system, or to add biocides or chemicals, is not a violation of Paragraph 2 of Subsection B of 20.2.50.127 NMAC.

C. Monitoring requirements: The owner or operator of a well with flowback that begins on or after the effective date of this Part shall conduct daily visual inspections of the flowback vessel and any associated equipment. Such inspections shall include:

(1) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated;

(2) visual inspection or monitoring of the control device to ensure that it is operating; and

(3) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

D. Recordkeeping requirements:

(1) The owner or operator of each flowback vessel subject to the emissions standards in Subsection B of 20.2.50.127 NMAC shall maintain the following records:

(a) the API number of the well and the associated facility location, including latitude and longitude coordinates;

(b) the date and time of the onset of flowback;

(c) the date and time that the flowback vessels were permanently disconnected, if applicable;

(d) the date and duration of any period where the control device was not operating; and

(e) records of the inspections required in Subsection C of 20.2.50.127 NMAC, including the following:

(i) time and date of each inspection;

(ii) a description of any problems observed;

(iii) a description of any corrective action(s) taken; and

(iv) the name and position of the person performing the corrective action(s).

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.127 NMAC - N, XX/XX/2022]

20.2.50.128 PROHIBITED ACTIVITY AND CREDIBLE EVIDENCE

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible evidence or information obtained by the department or provided to the department by a third party indicates that a source is not in compliance with the provisions of this Part that evidence or information may be used by the department for purposes of establishing whether a person has violated or is in violation of this Part.

[20.2.50.128 NMAC - N, XX/XX/2022]

HISTORY OF 20.2.50 NMAC: [**RESERVED**]

Certificate of Service

I hereby certify that on June 27, 2022 a copy of the attached Statement of Reasons was emailed to the persons listed below. A copy will be mailed first class upon request.

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