State of New Mexico
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
ENVIRONMENT DEPARTMENT

Michelle Lujan Grisham
Governor

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January 30, 2023

U.S. Department of the Interior
Tracey Stone-Manning, Director
Bureau of Land Management
1849 C St. NW, Room 5646
Washington, DC 20240,
Attention: 1004–AE79

Submitted electronically to: https://www.regulations.gov

RE: Comments on the Bureau of Land Management's Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule, Docket RIN 1004-AE79, Docket No. BLM-2022-0003

Dear Director Stone-Manning,

On behalf of the Energy, Minerals and Natural Resources Department ("EMNRD") and the New Mexico Environment Department ("NMED"), attached please find our respective comments on the Bureau of Land Management's ("BLM's") Notice of Proposed Rulemaking regarding the Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule ("Rule"), issued on November 30, 2022, the intent of which is to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases.

The State of New Mexico is taking significant steps to fight climate change and reduce ozone concentrations through the reduction of ozone precursors and methane from the oil and gas (O&G) sector. In early 2019, Governor Michelle Lujan Grisham issued Executive Order 2019-003 on Climate Change and Waste Prevention and signed into law New Mexico's Energy Transition Act, establishing New Mexico as a national leader in clean energy. In 2021, EMNRD's Oil Conservation Division ("OCD") finalized its nation-leading waste rules that regulate methane from upstream and midstream sources, ban routine venting and flaring, and require all operators to achieve 98% gas capture by 2026. Additionally, the New Mexico Environment Department (NMED) participates in the U.S. Environmental Protection Agency's ("EPA") Ozone Advance program and has recently finalized new nation-leading rules for ozone precursor pollutants from the oil and gas sector (20.2.50 NMAC or Part 50). These rules support New Mexico's overall efforts to reduce waste in the oil and gas sector, improve public health, and encourage environmental investment to reduce volatile organic compounds ("VOC") and greenhouse gases ("GHG") emissions that contribute to resource waste, unhealthy ozone levels and climate change.

Consistent with these state-level efforts, the State of New Mexico strongly supports the BLM's goals in proposing the Rule and encourages the BLM to clarify that the Rule does not preempt more stringent state standards, such as the rules recently adopted by EMNRD and NMED. If finalized with such a clarification, the

Rule will, as a co-benefit to BLM's primary purposes in proposing the Rule, significantly improve public health and air quality and advance the efforts of New Mexico and other states to meet greenhouse gas emissions reduction targets. The proposed revisions would also create a consistent and level playing field across production basins that span states, like the San Juan Basin, which crosses Colorado and New Mexico. Finally, the Rule will reduce waste of a valuable resource and increase royalties to the federal and state governments.

Our individual agencies have provided more detailed comments in the attachments to this letter – *see* Attachment A (EMNRD's Comments) and Attachment B (NMED's comments). Thank you for providing the opportunity to comment.

Sincerely,

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Attachment A

New Mexico Energy, Minerals and Natural Resource Department Comments on the Bureau of Land Management's Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule, Docket RIN 1004-AE79, Docket No. BLM-2022-0003

OCD appreciates the opportunity to comment on BLM's proposed rule ("Waste Rule"). The Waste Rule relies on a royalty-based approach to discourage venting and flaring of natural gas from wells on federal and tribal lands. We understand the statutory basis for this approach, and the recognition that environmental benefits are important, but ancillary to, BLM's primary objectives of minimizing the waste of natural gas and maximizing the public's compensation for the extraction of public resources by private parties.

OCD has a similar responsibility for the judicious management of oil and gas resources in the state of New Mexico. By statute, its primary objectives are the protection of correlative rights and the prevention of waste. To further these objectives during the exploration and production of oil and gas, New Mexico in 2021 adopted the regulations codified in 19.15.27 NMAC – Venting and Flaring of Natural Gas ("State Rule"), attached as Attachment A-Exhibit 2. The State Rule requires operators to meet standards and requirements that address wasteful and environmentally unsound practices during exploration and production. A copy of the State Rule is attached as Attachment A-2. OCD's primary concern in submitting these comments is to ensure that the BLM does not inadvertently preempt the State Rule and that it respects OCD's concurrent jurisdiction over activities on federal lands.

BLM has long recognized that OCD's rules apply to oil and gas wells on federal land, and that the operators of these wells must comply with those rules in addition to BLM's own rules. Accordingly, BLM and OCD have an extensive history of cooperation in managing the spacing and operation of oil and gas wells on federal land, which account for more than half of the active wells in New Mexico.

	Gas	Oil	Other*	Total
Private	4028	4146	1288	9462
State	3398	8504	1733	13635
Federal	16746	12815	1346	30907
Tribal	1937	638	19	2594

*Other well types, e.g., carbon dioxide, secondary recovery, and injection.

Because the Waste Rule and State Rule address the issue of waste from different perspectives, there should be no conflict between the rules, and indeed, for the most part OCD believes that the rules can be harmonized to avoid any perceived conflict. Stated differently, the application of the standards and requirements in the State Rule do not prevent an operator from complying with the royalty payment and other provisions in the Waste Rule. For instance, an operator who complies with the State Rule's prohibition on venting and flaring must pay the royalties on captured gas as required by the Waste Rule, while an operator who violates those same prohibitions may face enforcement action under State Rule and have to pay additional royalties on the vented or flared gas. However, as drafted the Waste Rule does not include an express acknowledgement that it does not preempt more stringent state standards.

Absent such an express acknowledgement, OCD is concerned that an operator will waste time and resources trying to evade or violate the State Rule's prohibition on venting and flaring or other standards and requirements, by trying to allege the existence of a conflict by relying on silence in the Waste Rule. While we do not think such a conflict exists, such tactics would needlessly delay OCD enforcement of the State Rule and divert agency resources; both of which contravene BLM's stated intent in the Waste Rule to support the waste prevention efforts of New Mexico, Colorado, and other states. OCD in Attachment A-Exhibit 1 has described some potential conflicts that an operator may attempt to exploit to avoid the force and effect of the State Rule. We believe these arguments could be avoided by insertion of affirmative text in the rule itself as opposed to just relying on the supporting material in the Federal Register.

BLM in the Waste Rule correctly recognized this potential for alleged conflict with the State Rule, particularly when the Waste Rule incorporates similar concepts, such as waste minimization plans and flaring restrictions. For this reason, BLM plainly stated that it did not intend to displace more stringent state standards and requirements that prevent waste during the exploration and production of oil and gas on federal lands. For instance, BLM in the Section-by-Section Discussion stated:

> Operators on Federal [lands] are already required to adhere to other applicable State, Tribal, and local laws and regulations....
>
> "To put it another way, operators in States [ ] that have more stringent standards than those contained in this proposed rule would be required to conform to the more stringent State [ ] standards in any event, regardless of whether the State [ ] receives a variance under the provisions of the proposed rule.

87 Fed.Reg. 73609. BLM reiterated this point in the Regulatory Impact Analysis ("RIA").

> State laws apply on Federal lands except when they are preempted by Federal law. Accordingly, the drilling, completion, and production operations of oil and gas wells on Federal lands are subject both to Federal and State regulation. If the requirements of a State regulation are more stringent than those of a Federal regulation, for example, the operator will comply with both the State and the Federal regulation by meeting the more stringent State requirement.
>
> ...Regardless of any difference in operational regulations, operators on Federal lands must comply with all Federal, State, and local permitting and reporting requirements.

RIA at 12.

OCD construes these statements to mean that the BLM intends that the Waste Rule will not preempt the State Rule (or the more stringent rules of another state) even in the event of an actual conflict. *California Coastal Commission v. Granite Rock Co.*, 480 U.S. 572, 583 (1987) (the federal regulations are "not only devoid of any expression of intent to preempt state law but appeared to assume that those submitting plans of operation would comply with state environmental protection law.") While OCD appreciates the BLM's intent in making these statements, OCD would encourage BLM to incorporate express language into the Federal Rule that makes it clear that the BLM Waste Rule is not preempting more stringent state standards and requirements. The BLM has used this approach before, and it has been endorsed by the courts. *Black Rock City, LLC v. Pershing County Board of Commissioners*, No. 3:12-CV-00435-RCJ (D. Nev. April 26, 2013), vacated and remanded on other grounds, 637 F. App'x 488 (9th Cir. 2016) (BLM permit that required compliance with state and local law nullified a preemption claim regarding a local ordinance); *see also Citizens for Health v. Leavitt*, 428 F.3d 167, 174 (3rd Cir. 2005) (preemption provisions in a federal rule established the "floor" for privacy protection, allowing "more stringent" state law to control). To this end, OCD proposes that the BLM adopt the following language into the Waste Rule:

> Nothing in this rule shall be construed to preempt a state law, regulation, or rule, including any standard or requirement, that requires an operator to restrict, limit, or otherwise control the venting, flaring or leaking of natural gas from any well or associated facility that is more stringent than [the Waste Rule].

OCD understands that the BLM proposes to address this issue in part by allowing the states to apply for variances from the provisions of the Waste Rule, but OCD believes that variances are neither necessary nor an appropriate substitute for deference to more stringent state waste prevention rules. As the BLM itself recognizes, operators already must comply with more stringent state standards and requirements. There is no need for a variance if a more stringent state standard or requirement already applies, particularly if the Waste Rule eliminates any confusion by expressly requiring compliance with it. OCD also is concerned that the variance process, which does not have well-defined parameters, will divert significant agency resources that are better directed to enforcing existing state waste prevention rules. Finally, to the extent that the BLM envisions the variance provision as a mechanism to foster cooperation between the BLM and state agencies, OCD believes that MOUs are a well-established and more flexible approach for the agencies to work together in reconciling duplicative or conflicting administrative requirements that might impose unnecessary or undue regulatory burden on prudent operators.

ATTACHMENT A - EXHIBIT 1

This Exhibit identifies potential conflicts between the Waste Rule and the State Rule, 19.15.27 NMAC – *Venting and Flaring of Natural Gas*. The list of potential conflicts is not intended to be exhaustive; other potential conflicts may exist that are not identified below.

Gas Wells. 19.15.2.7(G)(6) NMAC defines "gas well" as a "a well producing gas from a gas pool, or a well with a gas-oil ratio exceeding 100,000 scf gas per barrel of oil producing from an oil pool." 19.15.2.7(O)(4) NMAC defines "oil well" as "a well a well capable of producing oil and that is not a gas well as defined in [19.15.2.7(G)(6) NMAC]." Section 3179.3 defines "gas well" as having a gas-oil ratio greater than 6,000 scf gas per barrel of oil. OCD's definitions determine, among other things, the applicable spacing and setback rules for exploration and production on federal lands. BLM's definition, if applied broadly, could upset these well-established rules, creating considerable confusion in the development and management of oil and gas resources. Most notably, it could impact OCD's longstanding authority to regulate the spacing of oil or gas wells across state, private and federal lands in New Mexico. OCD believes that this issue could be resolved if the Waste Rule expressly stated that its definition of "gas well" is limited to the purposes of the Waste Rule and is not intended for any other purpose.

For the concerns flagged below, the resolution for all would be an affirmative statement in the Waste Rule that more stringent state standards and requirements are not preempted.

Applications for Permit to Drill. 19.15.27.9(D)(7) NMAC prohibits OCD from approving an APD unless the well has 100% takeaway capacity or alternative beneficial uses for the natural gas. Section 3162.3-1(k)(1) authorizes BLM to approve an APD even if it results in unreasonable and undue waste of natural gas, while Section 3179.4(b)(14) allows the BLM to approve an APD for a well that is not connected to a pipeline and to flare all the gas indefinitely and royalty-free.

Drilling. 19.15.27.8(B)(1) NMAC requires an operator to capture or combust natural gas "if technically feasible using best industry practices and control technologies", such as portable flare stack, and to divert the gas as soon as possible. Section 3179.4(b)(1) allows royalty-free flaring of all gas during drilling and does not require the operator to use a technically feasible practice or technology to capture the gas at the earliest possible time.

Well Completions and Recompletions. 19.15.27.8(C) NMAC defines two separate phases for completions and recompletions, both of which require the capture of gas at the earliest possible time. During initial flowback, the operator must capture liquids in a tank and commence operation of the separator as soon as technically feasible. During separation flowback, the operator must capture and route the gas to the separator. Section 3179.4(b)(2) allows royalty-free flaring of 10,000 Mcf of gas during completion of a new well and royalty-free flaring of 5,000 Mcf of gas during recompletion of an existing well that is connected to a pipeline. For recompletion of an existing well that is not connected to a pipeline, the Federal Rule allows unlimited royalty-free flaring.

Production Tests. 19.15.27.8(D)(4)(k) NMAC allows flaring during a production test for no more than 24 hours. Section 3179.4(b)(3) allows royalty-free flaring during an initial production test of 20,000 Mcf or 20 days, whichever comes first, or 60 days if approved by BLM, and 24 hours for subsequent tests.

Exploratory Wells. 19.15.27.8(D)(3) NMAC allows flaring by an exploratory well, narrowly defined as a well whose spacing unit is more than 2 miles from an existing gathering pipeline, during the first 12 months of production if the operator (1) complies with its statewide gas capture requirements, and (2) no later than 15 days after determining that the well is capable of producing in paying quantities, informs OCD when it will connect the well to a gathering system. Section 3179.4(b)(5) allows royalty-free flaring by an "exploratory coalbed methane well", a term which is not defined, with no volume or time limit, and does not address other types of exploratory wells.

Emergencies. 19.15.27.D(1) NMAC allows flaring during an emergency no more than 4 times per 30 days, or if due to the failure of a natural gas gathering system, 8 hours after notification by the gathering system operator. Section 3179.4(b)(6) allows royalty-free flaring during an emergency for 48 hours, with no limit on the number of emergencies.

Downhole Well Maintenance and Liquids Unloading. 19.15.27.D(2) NMAC allows venting during downhole well maintenance only when the operator uses a workover rig or other specialty equipment designed to minimize venting and allows venting during liquids unloading only until the well achieves stabilized rate and pressure. Section 3179.4(b)(9) allows royalty-free venting for 24 hours during downhole well maintenance, and unlimited royalty-free venting during liquids unloading.

Pipeline Capacity Constraints. 19.15.27(D) NMAC prohibits flaring caused by alleged pipeline capacity constraints, except for an emergency, unscheduled maintenance, or malfunction of the natural gas gathering system, and then only for 8 hours after notification by the gathering system operator. Section 3179.4(b)(12) allows royalty-free flaring of 1,050 Mcf of gas per month for each lease, unit, or communitized area which is caused by "pipeline capacity constraints, midstream processing failures, and other similar events that prevent oil-well gas from being transported through the connected pipeline". Additionally, the Federal Rule does not define "pipeline capacity constraints", so it is not clear which wells are entitled to claim royalty-free flaring, e.g., only those wells connected to a pipeline with 100% takeaway capacity or any well regardless of its connection to a pipeline or the pipeline's takeaway capacity.

Flares.

Location. 19.15.27.8(B)(2) NMAC requires a flare used during drilling operations to be located at least 100 feet from the nearest surface hole location, and 19.15.27(E)(4) NMAC requires a flare constructed after May 25, 2021 to be located at least 100 feet from the well and storage tanks. Section 3179.6(a) requires a flare to be located "a sufficient distance from the tank battery containment area and any other significant structures or objects."

Measuring Devices. 19.15.27.8(F) NMAC requires the measuring device on a flare to conform to an industry standard, such as API MPMS Chapter 14.10, and be installed so that bypass is not possible. Section 3179.9(b)(1) requires an orifice meter on a flare, but does not reference an industry standard, and does not require the flare to be constructed to prevent bypass.

ATTACHMENT A - EXHIBIT 2

EMNRD OCD WASTE RULE

TITLE 19 **NATURAL RESOURCES AND WILDLIFE**

CHAPTER 15 **OIL AND GAS**

PART 27 **VENTING AND FLARING OF NATURAL GAS**

19.15.27.1 **ISSUING AGENCY:** Oil Conservation Commission.

[19.15.27.1 NMAC – N, 05/25/2021]

19.15.27.2 **SCOPE:** 19.15.27 NMAC applies to persons engaged in oil and gas exploration and production within New Mexico.

[19.15.27.2 NMAC – N, 05/25/2021]

19.15.27.3 **STATUTORY AUTHORITY:** 19.15.27 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11 and Section 70-2-12 NMSA 1978.

[19.15.27.3 NMAC – N, 05/25/2021]

19.15.27.4 **DURATION:** Permanent.

[19.15.27.4 NMAC – N, 05/25/2021]

19.15.27.5 **EFFECTIVE DATE:** May 25, 2021, unless a later date is cited at the end of a section.

[19.15.27.5 NMAC – N, 05/25/2021]

19.15.27.6 **OBJECTIVE:** To regulate the venting and flaring of natural gas from wells and production equipment and facilities to prevent waste and protect correlative rights, public health, and the environment.

[19.15.27.6 NMAC – N, 05/25/2021]

19.15.27.7 **DEFINITIONS:** Terms shall have the meaning specified in 19.15.2 NMAC except as specified below.

A. **"ALARM"** means advanced leak and repair monitoring technology for detecting natural gas leaks or releases that is not required by applicable state or federal law, rule, or regulation, and which the division has approved as eligible to earn a credit against the reported volume of lost natural gas pursuant to Paragraph (4) of Subsection B of 19.15.27.9 NMAC.

B. "**Average daily well production**" means the number derived by dividing the total volume of natural gas produced from a single well in the preceding 12 months by the number of days that natural gas was produced from the well during the same period.

C. "**Average daily facility production**" means, for a facility receiving production from two or more wells, the number derived by dividing the total volume of natural gas produced from all wells at the facility during the preceding 12 months by the number of days, not to exceed 365, that natural gas was produced from one or more wells during the same period.

D. **"AVO"** means audio, visual and olfactory.

E. **"Completion operations"** means the period that begins with the initial perforation of the well in the completed interval and concludes at the end of separation flowback.

F. **"Drilling operations"** means the period that begins when a well is spud and concludes when casing and cementing has been completed and casing slips have been set to install the tubing head.

G. **"Exploratory well"** means a well located in a spacing unit the closest boundary of which is two miles or more from:

(1) the outer boundary of a defined pool that has produced oil or gas from the formation to which the well is or will be completed; and

(2) an existing gathering pipeline as defined in 19.15.28 NMAC.

H. **"Emergency"** means a temporary, infrequent, and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment, but does not include an event arising from or related to:

(1) the operator's failure to install appropriate equipment of sufficient capacity to accommodate the anticipated or actual rate and pressure of production;

(2) except as provided in Subparagraph (4), the operator's failure to limit production when the production rate exceeds the capacity of the related equipment or natural gas gathering system as defined in 19.15.28 NMAC, or exceeds the sales contract volume of natural gas;

(3) scheduled maintenance;

(4) venting or flaring of natural gas for more than eight hours after notification that is caused by an emergency, unscheduled maintenance, or malfunction of a natural gas gathering system;

(5) the operator's negligence;

(6) recurring equipment failure 4 or more times within a single reporting area pursuant to Subsection A of 19.15.27.9 experienced by the operator within the preceding 30 days; or

(7) Four or more emergencies within a single reporting area, pursuant to Subsection A of 19.15.27.9 NMAC, experienced by the operator within the preceding 30 days, unless the division determines the operator could not have reasonably anticipated the current event and it was beyond the operator's control.

I. **"Flare" or "Flaring"** means the controlled combustion of natural gas in a device designed for that purpose.

J. **"Flare stack"** means a device equipped with a burner used to flare natural gas.

K. **"Gas-to-oil ratio (GOR)"** for purposes of 19.15.27 NMAC means the ratio of natural gas to oil in the production stream expressed in standard cubic feet of natural gas per barrel of oil.

L. **"Initial flowback"** means the period during completion operations that begins with the onset of flowback and concludes when it is technically feasible for a separator to function.

M. **"Malfunction"** means a sudden, unavoidable failure or breakdown of equipment beyond the reasonable control of the operator that substantially disrupts operations, but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation, or other preventable equipment failure or breakdown.

N. **"N_2"** means nitrogen gas.

O. **"Natural gas"** means a gaseous mixture of hydrocarbon compounds, primarily composed of methane, and includes both casinghead gas and gas as those terms are defined in 19.15.2 NMAC.

P. **"Production operations"** means the period that begins on the earlier of 31 days following the commencement of initial flowback or following completion of separation flowback and concludes when the well is plugged and abandoned.

Q. **"Producing in paying quantities"** mean the production of a quantity of oil and gas that yields revenue in excess of operating expenses.

R. **"Separation flowback"** means the period during completion operations that begins when it is technically feasible for a separator to function and concludes no later than 30 days after the commencement of initial flowback.

S. **"Vent" or "Venting"** means the release of uncombusted natural gas to the atmosphere.

[19.15.27.7 NMAC – N, 05/25/2021]

19.15.27.8 VENTING AND FLARING OF NATURAL GAS:

A. Venting or flaring of natural gas during drilling, completion, or production operations that constitutes waste as defined in 19.15.2 NMAC is prohibited. The operator has a general duty to maximize the recovery of natural gas by minimizing the waste of natural gas through venting and flaring. During drilling, completion and production operations, the operator may vent or flare natural gas only as authorized in Subsections B, C and D of 19.15.27.8 NMAC. In all circumstances, the operator shall flare rather than vent natural gas except when flaring is technically infeasible or would pose a risk to safe operations or personnel safety, and venting is a safer alternative than flaring.

B. **Venting and flaring during drilling operations.**

(1) The operator shall capture or combust natural gas if technically feasible using best industry practices and control technologies.

(2) A properly-sized flare stack shall be located at a minimum of 100 feet from the nearest surface hole location unless otherwise approved by the division.

(3) In an emergency or malfunction, the operator may vent natural gas to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment. The operator shall report natural gas vented or flared during an emergency or malfunction to the division pursuant to Paragraph (1) of Subsection G of 19.15.27.8 NMAC.

C. **Venting and flaring during completion or recompletion operations.**

(1) During initial flowback, the operator shall route flowback fluids into a completion or storage tank and, if technically feasible under the applicable well conditions, flare rather than vent and commence operation of a separator as soon as it is technically feasible for a separator to function.

(2) During separation flowback, the operator shall capture and route natural gas from the separation equipment:

(a) to a gas flowline or collection system, reinject into the well, or use on-site as a fuel source or other purpose that a purchased fuel or raw material would serve; or

(b) to a flare if routing the natural gas to a gas flowline or collection system, reinjecting it into the well, or using it on-site as a fuel source or other purpose that a purchased fuel or raw material would serve would pose a risk to safe operation or personnel safety.

(3) If natural gas does not meet gathering pipeline quality specifications, the operator may flare the natural gas for 60 days or until the natural gas meets the pipeline quality specifications, whichever is sooner, provided that:

(a) a properly-sized flare stack is equipped with an automatic igniter or continuous pilot;

(b) the operator analyzes natural gas samples twice per week;

(c) the operator routes the natural gas into a gathering pipeline as soon as the pipeline specifications are met; and

(d) the operator provides the pipeline specifications and natural gas analyses to the division upon request.

D. **Venting and flaring during production operations.** The operator shall not vent or flare natural gas except:

(1) during an emergency or malfunction;

(2) to unload or clean-up liquid holdup in a well to atmospheric pressure, provided

(a) the operator does not vent after the well achieves a stabilized rate and pressure;

(b) for liquids unloading by manual purging, the operator remains present on-site until the end of unloading or posts at the well site the contact information of the personnel conducting the liquids unloading operation and ensures that personnel remains within 30 minutes' drive time of the well being unloaded until the end of unloading, takes all reasonable actions to achieve a stabilized rate and pressure at the earliest practical time and takes reasonable actions to minimize venting to the maximum extent practicable;

(c) for a well equipped with a plunger lift system or an automated control system, the operator optimizes the system to minimize the venting of natural gas; or

(d) during downhole well maintenance, only when the operator uses a workover rig, swabbing rig, coiled tubing unit or similar specialty equipment and minimizes the venting of natural gas to the extent that it does not pose a risk to safe operations and personnel safety and is consistent with best management practices;

(3) during the first 12 months of production from an exploratory well, or as extended by the division for good cause shown, provided:

(a) the operator proposes and the division approves the well as an exploratory well;

(b) the operator is in compliance with its statewide gas capture requirements; and

(c) within 15 days of determining an exploratory well is capable of producing in paying quantities, the operator submits an updated form C-129 to the division, including a natural gas management plan and timeline for connecting the well to a natural gas gathering system or as otherwise approved by the division; or

(4) during the following activities unless prohibited by applicable state or federal law, rule, or regulation for the emission of hydrocarbons and volatile organic compounds:

(a) gauging or sampling a storage tank or other low-pressure production vessel;

(b) loading out liquids from a storage tank or other low-pressure production vessel to a transport vehicle;

(c) repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance;

(d) normal operation of a gas-activated pneumatic controller or pump;

(e) normal operation of a storage tank or other low-pressure production vessel, but not including venting from a thief hatch that is not properly closed or maintained on an established schedule;

(f) normal operation of dehydration units and amine treatment units;

(g) normal operations of compressors, compressor engines, and turbines;

(h) normal operations of valves, flanges and connectors that is not the result of inadequate equipment design or maintenance;

(i) a bradenhead test;

(j) a packer leakage test;

(k) a production test lasting less than 24 hours unless the division requires or approves a longer test period;

(l) when natural gas does not meet the gathering pipeline specifications, provided the operator analyzes natural gas samples twice per week to determine whether the specifications have been achieved, routes the natural gas into a gathering pipeline as soon as the pipeline specifications are met and provides the pipeline specifications and natural gas analyses to the division upon request; or

(m) Commissioning of pipelines, equipment, or facilities only for as long as necessary to purge introduced impurities from the pipeline or equipment.

E. Performance standards

(1) The operator shall design completion and production separation equipment and storage tanks for maximum anticipated throughput and pressure to minimize waste.

(2) The operator of a permanent storage tank associated with production operations that is routed to a flare or control device installed after May 25, 2021, shall equip the storage tank with an automatic gauging system that reduces the venting of natural gas.

(3) The operator shall combust natural gas in a flare stack that is properly sized and designed to ensure proper combustion efficiency.

(a) A flare stack installed or replaced after May 25, 2021, shall be equipped with an automatic ignitor or continuous pilot.

(b) A flare stack installed before May 25, 2021, shall be retrofitted with an automatic ignitor, continuous pilot, or technology that alerts the operator that the flare may have malfunctioned no later than 18 months after May 25, 2021.

(c) A flare stack located at a well or facility, with an average daily production of equal to or less than 60,000 cubic feet of natural gas shall be equipped with an automatic ignitor or continuous pilot if the flare stack is replaced after May 25, 2021.

(4) A flare stack constructed after May 25, 2021, shall be securely anchored and located at least 100 feet from the well and storage tanks unless otherwise approved by the division.

(5) The operator shall conduct an AVO inspection on the frequency specified below to confirm that all production equipment is operating properly and there are no leaks or releases except as allowed in Subsection D of 19.15.27.8 NMAC.

(a) During an AVO inspection the operator shall inspect all components, including flare stacks, thief hatches, closed vent systems, pumps, compressors, pressure relief devices, valves, lines, flanges, connectors, and associated piping to identify defects, leaks, and releases by:

(i) a comprehensive external visual inspection;

(ii) listening for pressure and liquid leaks; and

(iii) smelling for unusual and strong odors.

(b) The operator shall conduct an AVO inspection weekly:

(i) during the first year of production; and

(ii) on a well or facility with an average daily production greater than 60,000 cubic feet of natural gas.

(c) The operator shall conduct an AVO inspection weekly if the operator is on site, and in no case less than once per calendar month with at least 20 calendar days between inspections:

(i) on a well or facility with an average daily production equal to or less than 60,000 cubic feet of natural gas; and

(ii) on shut-in, temporarily abandoned, or inactive wells.

(d) The operator shall make and keep a record of an AVO inspection for not less than five years and make such record available for inspection by the division upon request.

(6) Subject to the division's prior written approval, the operator may use a remote or automated monitoring technology to detect leaks and releases in lieu of an AVO inspection.

(7) for facilities constructed after May 25, 2021, facilities shall be designed to minimize waste;

(8) Operators have an obligation to minimize waste and shall resolve emergencies as quickly and safely as is feasible.

F. Measurement or estimation of vented and flared natural gas.

(1) The operator shall measure or estimate the volume of natural gas that it vents, flares, or beneficially uses during drilling, completion, and production operations regardless of the reason or authorization for such venting or flaring.

(2) The operator shall install equipment to measure the volume of natural gas flared from existing process piping or a flowline piped from equipment such as high pressure separators, heater treaters, or vapor recovery units associated with a well or facility associated with a well authorized by an APD issued after May 25, 2021, that has an average daily production greater than 60,000 cubic feet of natural gas.

(3) Measuring equipment shall conform to an industry standard such as American Petroleum Institute (API) Manual of Petroleum Measurement Standards (MPMS) Chapter 14.10 Measurement of Flow to Flares.

(4) Measuring equipment shall not be designed or equipped with a manifold that allows the diversion of natural gas around the metering element except for the sole purpose of inspecting and servicing the measurement equipment.

(5) If metering is not practicable due to circumstances such as low flow rate or low pressure venting and flaring, the operator may estimate the volume of vented or flared natural gas using a methodology that can be independently verified.

(6) For a well that does not require measuring equipment, the operator shall estimate the volume of vented and flared natural gas based on the result of an annual GOR test for that well reported on form C-116 to allow the division to independently verify the volume and rate of the flared natural gas.

(7) The operator shall install measuring equipment whenever the division determines that metering is practicable or the existing measuring equipment or GOR test is not sufficient to measure the volume of vented and flared natural gas.

G. Reporting of vented or flared natural gas.

(1) Venting or flaring caused by an emergency, a malfunction or of long duration.

(a) The operator shall notify the division of venting or flaring that exceeds 50 MCF in volume and either results from an emergency or malfunction, or lasts eight hours or more cumulatively within any 24-hour period from a single event by filing a form C-129 in lieu of a C-141, except as provided by Subparagraph (d) of Paragraph (1) of Subsection G of 19.15.27.8 NMAC, with the division as follows:

(i) for venting or flaring that equals or exceeds 50 MCF but less than 500 MCF from a single event, notify the division in writing by filing a form C-129 no later than 15 days following discovery or commencement of venting or flaring;

(ii) for venting or flaring that equals or exceeds 500 MCF or otherwise qualifies as a major release as defined in 19.15.29.7 NMAC from a single event, notify the division verbally or by e-mail as soon as possible and no later than 24 hours following discovery or commencement of venting or flaring and provide the information required in form C-129. No later than 15 days following the discovery or commencement of venting or flaring, the operator shall file a form C-129 that verifies, updates, or corrects the verbal or e-mail notification; and

(iii) no later than 15 days following the termination of venting or flaring, notify the division by filing a form C-129.

(b) The operator shall provide and certify the accuracy of the following information in the form C-129:

(i) operator's name;

(ii) name and type of facility;

(iii) equipment involved;

(iv) compositional analysis of vented or flared natural gas that is representative of the well or facility;

(v) date(s) and time(s) that venting or flaring was discovered or commenced and terminated;

(vi) measured or estimated volume of vented or flared natural gas;

(vii) cause and nature of venting or flaring;

(viii) steps taken to limit the duration and magnitude of venting or flaring; and

(ix) corrective actions taken to eliminate the cause and recurrence of venting or flaring.

(c) At the division's request, the operator shall provide and certify additional information by the specified date.

(d) The operator shall file a form C-141 instead of a form C-129 for a release that includes liquid during venting or flaring that is or may be a major or minor release under 19.15.29.7 NMAC.

(2) Monthly reporting of vented and flared natural gas. For each well or facility at which venting or flaring occurred, the operator shall separately report the volume of vented natural gas and volume of flared natural gas for each month in each category listed below. Beginning October 1, 2021, the operator shall gather data for quarterly reports in a format specified by the division and submit by February 15, 2022 for the fourth quarter and May 15, 2022 for the first quarter. Beginning April 2022, the operator shall submit a form C-115B monthly on or before the 15th day of the second month following the month in which it vented or flared natural gas. The operator shall specify whether it estimated or measured each reported volume. In filing the initial report, the operator shall provide the methodology (measured or estimated using calculations and industry standard factors) used to report the volumes and shall report changes in the methodology on future forms. The operator shall make and keep records of the measurements and estimates, including records showing how it calculated the estimates, for no less than five years and make such records available for inspection by the division upon request. The categories are:

(a) emergency;

(b) non-scheduled maintenance or malfunction, including the abnormal operation of equipment;

(c) routine repair and maintenance, including blowdown and depressurization;

(d) routine downhole maintenance, including operation of workover rigs, swabbing rigs, coiled tubing units and similar specialty equipment;

(e) manual liquid unloading;

(f) storage tanks;

(g) insufficient availability or capacity in a natural gas gathering system during the separation phase of completion operations or production operations;

(h) natural gas that is not suitable for transportation or processing because:

(i) N_2, H_2S, or CO_2 concentrations do not meet gathering pipeline quality specifications; or

(ii) O_2 concentrations do not meet gathering pipeline quality specifications except during commissioning of pipelines, equipment, or facilities pursuant to Subparagraph (l) of Paragraph (4) of Subsection D of 19.15.27.8 NMAC, except as otherwise approved by the division;

(i) venting as a result of normal operation of pneumatic controllers and pumps, unless the operator vents or flares less than 500,000 cubic feet per year of natural gas;

(j) improperly closed or maintained thief hatches;

(k) venting or flaring in excess of eight hours that is caused by an emergency, unscheduled maintenance or malfunction of a natural gas gathering system as defined in 19.15.28 NMAC;

(l) venting and flaring from an exploratory well; and

(m) other surface waste as defined in Subparagraph (b) of Paragraph (1) of Subsection W of 19.15.2.7 NMAC that is not described above.

(3) Upon submittal of the C-115B report, the division will compile and publish on the division's website an operator's vented and flared natural gas information for each month on a volumetric and gas capture percentage basis.

(a) To calculate the lost natural gas on a volumetric basis, the operator shall deduct the volume of natural gas sold, used for beneficial use, vented or flared during an emergency, and vented or flared because it was not suitable for transportation or processing due to N_2, H_2S, or CO_2 concentrations, vented as a result of normal operation of pneumatic controllers and pumps if reported pursuant to Subparagraph (i) of Paragraph (2) of Subsection G of 19.15.27.8 NMAC, or vented or flared from an exploratory well with division approval from the natural gas produced.

(b) To calculate the natural gas captured on a percentage basis, the operator shall deduct the volume of lost gas calculated in Subparagraph (a) of Paragraph (3) of Subsection G of 19.15.27.8 NMAC from the total volume of natural gas produced and divide by the total volume of natural gas produced.

(4) Beginning June 2022, the operator shall provide a copy of the C-115B to the New Mexico State Land Office for a well or facility in which the state owns a royalty interest, and the operator shall notify all royalty interest owners of their ability to obtain the information from the division's website at the time the initial C-115B is filed.

(5) Upon the New Mexico environment department's request, the operator shall promptly provide a copy of any form filed pursuant to 19.15.27 NMAC.

[19.15.27.8 NMAC – N, 05/25/2021]

19.15.27.9 STATEWIDE NATURAL GAS CAPTURE REQUIREMENTS:

A. Statewide natural gas capture requirements. Commencing April 1, 2022, the operator shall reduce the annual volume of vented and flared natural gas in order to capture no less than ninety-eight percent of the natural gas produced from its wells in each of two reporting areas, one north and one south of the Township 10 North line, by December 31, 2026. The division shall calculate and publish on the division's website each operator's baseline natural gas capture rate based on the operator's fourth quarter 2021 and first quarter 2022 quarterly reports as per Paragraph (2) of Subsection G of 19.15.27.8 NMAC. In each calendar year between January 1, 2022 and December 31, 2026, the operator shall increase its annual percentage of natural gas captured in each reporting area in which it operates based on the following formula: (baseline loss rate minus two percent) divided by five, except that for 2022 only, an operator's percentage of natural gas captured shall not be less than seventy-five percent of the annual gas capture percentage increase (2022 baseline loss rate minus two percent divided by five times 0.75), and the balance shall be captured in 2023.

(1) The following table provides examples of the formula based on a range of baseline natural gas capture rates.

Baseline Natural Gas Capture Rate	Minimum Required Annual Natural Gas Capture Percentage Increase
90-98%	0-1.6%

80-89%	>1.6-3.6%
70-79%	>3.6-5.6%
0-69%	>5.6-19.6%

(2) If the operator's baseline capture rate is less than sixty percent, the operator shall submit by the specified date to the division for approval a plan to meet the minimum required annual capture percentage increase.

(3) An operator's acquisition or sale of one or more wells from another operator shall not affect its annual natural gas capture requirements. No later 60 days following the acquisition or sale, the operator may file a written request to the division requesting to modify its gas capture percentage requirements for good cause based on its acquisition or sale. The division may approve, approve with conditions, or deny the request in its sole discretion.

(4) No later than March 30 following the reporting year, an operator that has not met its annual natural gas capture requirement for the previous year shall submit to the division a compliance plan demonstrating its ability to comply with its annual gas capture requirement for the current year. If the division determines, after a reasonable opportunity to meet with the operator, that the compliance plan does not demonstrate the operator's ability to comply with its annual gas capture requirement for the current year the operator's approved APDs for wells that have not been spud shall be suspended pending a division hearing to be held no later than 30 days after the determination. Nothing in this subparagraph shall prevent the division from taking any other action authorized by law for the operator's failure to comply with its annual gas capture requirement, including shutting in wells and assessing civil penalties.

B. Accounting. No later than February 28 of each year beginning in 2023, the operator shall submit a report certifying compliance with its statewide gas capture requirements. The operator shall determine compliance with its statewide gas capture requirements by deducting any ALARM credits approved pursuant to this subsection from the aggregated volume of lost gas calculated for each month during the preceding year pursuant to Subparagraph (a) of Paragraph (3) of Subsection G of 19.15.27.8 NMAC, deducting that aggregated volume of lost gas from the aggregated volume of natural gas produced for each month during the preceding year, and dividing that volume by the aggregated volume of natural gas produced for each month during the preceding year.

(1) An operator that used a division-approved ALARM technology to monitor for leaks and releases may obtain a credit against the volume of lost natural gas if it discovered the leak or release using the ALARM technology and the operator:

(a) isolated the leak or release within 48 hours following field verification;

(b) repaired the leak or release within 15 days following field verification or another date approved by the division;

(c) timely notified the division by filing a form C-129 or form C-141; and

(d) used ALARM monitoring technology as a routine and on-going aspect of its waste-reduction practices.

(i) For discrete waste-reduction practices such as aerial methane monitoring, the operator must use the technology at least twice per year; and

(ii) for waste-reduction practices such as automated emissions monitoring systems that operate routinely or continuously, the division will determine the required frequency of use.

(e) The division shall publish a list of division-approved ALARM technologies on the division's website.

(2) An operator may file an application with the division for a credit against its volume of lost natural gas that identifies:

(a) the ALARM technology used to discover the leak or release;

(b) the dates on which the leak or release was discovered, field-verified, isolated and repaired;

(c) the method used to measure or estimate the volume of natural gas leaked or released which method shall be consistent with Subsection F of 19.15.27.8 NMAC;

(d) a description and the date of each action taken to isolate and repair the leak or release;

(e) visual documentation or other verification of discovery, isolation and repair of the leak or release;

(f) a certification that the operator did not know or have reason to know of the leak or release before discovery using ALARM technology; and

(g) a description of how the operator used ALARM technology as a routine and ongoing aspect of its waste reduction practices.

(3) For each leak or release reported by an operator that meets the requirements of Paragraphs (3) and (4) of Subsection B of 29.15.28.10 NMAC, the division, in its sole discretion, may approve a credit that the operator can apply against its reported volume of lost natural gas as follows:

(a) a credit of forty percent of the volume of natural gas discovered and isolated within 48 hours of discovery and timely repaired;

(b) an additional credit of twenty percent if the operator used ALARM technology no less than once per calendar quarter as a routine and ongoing aspect of its waste reduction practices.

(4) A division approved ALARM credit shall:

(a) be used only by the operator who submitted the application pursuant to Paragraph (4) of Subsection B of 29.15.27.10 NMAC;

(b) not be transferred to or used by another operator, including a parent, subsidiary, related entity, or person acquiring the well;

(c) be used only once; and

(d) expire 24 months after division approval.

(5) The division will publish a list of approved ALARM technology.

C. Third party verification. The division may request that an operator retain a third party to verify any data or information collected or reported pursuant to this Part, make recommendations to correct or improve the collection and reporting of data and information, submit a report of the verification and recommendations to the division by the specified date, and implement the recommendations in the manner approved by the division. If the division and the operator cannot reach agreement on the division's request, the operator may file an application for hearing before the division. The operator, at its own expense, shall retain a third party approved by the division to conduct the activities agreed to by the division and the operator or ordered by the division following a hearing.

D. Natural gas management plan.

(1) After May 25, 2021, the operator shall file a natural gas management plan with each APD for a new or recompleted well. The operator may file a single natural gas management plan for multiple wells drilled or recompleted from a single well pad or that will be connected to a central delivery point. The natural gas management plan shall describe the actions that the operator will take at each proposed well to meet its statewide natural gas capture requirements and to comply with the requirements of Subsections A through F of 19.15.27.8 NMAC, including for each well:

(a) the operator's name and OGRID number;

(b) the name, API number, location and footage;

(c) the anticipated dates of drilling, completion and first production;

(d) a description of operational best practices that will be used to minimize venting during active and planned maintenance; and

(e) the anticipated volumes of liquids and gas production and a description of how separation equipment will be sized to optimize gas capture.

(2) Beginning April 1, 2022, an operator that, at the time it submits an APD for a new or recompleted well is, cumulatively for the year, not in compliance with its baseline natural gas capture rate for the applicable reporting area if the APD is submitted on or after April 1, 2022 or its natural gas capture requirement for the previous year if the APD is submitted in 2023 or after shall also include the following information in the natural gas management plan:

(a) the anticipated volume of produced natural gas in units of MCFD for the first year of production;

(b) the existing natural gas gathering system the operator has contracted or anticipates contracting with to gather the natural gas, including:

(i) the name of the natural gas gathering system operator;

(ii) the name and location of the natural gas gathering system;

(iii) a map of the well location and the anticipated pipeline route connecting the production operations to the existing or planned interconnect of the natural gas gathering system.; and

(iv) the maximum daily capacity of the segment or portion of the natural gas gathering system to which the well will be connected; and

(c) the operator's plans for connecting the well to the natural gas gathering system, including:

(i) the anticipated date on which the natural gas gathering system will be available to gather the natural gas produced from the well;

(ii) whether the natural gas gathering system has or will have capacity to gather the anticipated natural gas production volume from the well prior to the date of first production; and

(iii) whether the operator anticipates the operator's existing well(s) connected to the same segment or portion of the natural gas gathering system, referenced in Item (iv) of Subparagraph (b) of Paragraph (2) of Subsection D or 19.15.27.9 NMAC will continue to be able to meet anticipated increases in line pressure caused be the well and the operator's plan to manage production in response to the increased line pressure.

(3) The operator may assert confidentiality for information specified in Paragraph (2) of Subsection D of 19.15.27.9 NMAC pursuant to Section 71-2-8 NMSA 1978.

(4) The operator shall certify that it has determined based on the available information at the time of submitting the natural gas management plan either:

(a) it will be able to connect the well to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the volume of natural gas the operator anticipates the well will produce commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system; or

(b) it will not be able to connect to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the volume of natural gas the operator anticipates the well will produce commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system.

(5) If the operator determines it will not be able to connect a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced on the date of first production from the well, the operator shall either shut-in the well until the operator submits the certification required by Paragraph (4) of Subsection D of 19.15.27.9 NMAC or submit a venting and flaring plan to the division that evaluates and selects one or more of the potential alternative beneficial uses for the natural gas until a natural gas gathering system is available, including:

(a) power generation on lease;

(b) power generation for grid;

(c) compression on lease;

(d) liquids removal on lease;

(e) reinjection for underground storage;

(f) reinjection for temporary storage;

(g) reinjection for enhanced oil recovery;

(h) fuel cell production; and

(i) other alternative beneficial uses approved by the division.

(6) If, at any time after the operator submits the natural gas management plan and before the well is spud:

(a) the operator becomes aware that the natural gas gathering system it planned to connect the well to has become unavailable or will not have capacity to transport one hundred percent of the production from the well, no later than 20 days after becoming aware of such information, the operator shall submit for the division's approval a new or revised venting and flaring plan containing the information specified in Paragraph (5) of Subsection D of 19.15.27.9 NMAC; and

(b) the operator becomes aware that it has, cumulatively for the year, become out of compliance with its baseline natural gas capture rate or natural gas capture requirement, no later than 20 days after becoming aware of such information, the operator shall submit for the division's approval a new or revised natural gas management plan for each well it plans to spud during the next 90 days containing the information specified in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and shall file an update for each plan until the operator is back in compliance with its baseline natural gas capture rate or natural gas capture requirement.

(7) The division may deny the APD or conditionally approve the APD if the operator does not make a certification, fails to submit an adequate venting and flaring plan, which includes alternative beneficial uses for the anticipated volume of natural gas produced, or if the division determines that the operator will not have adequate natural gas takeaway capacity at the time a well will be spud.

[19.15.27.9 NMAC – N, 05/25/2021]

Attachment B

New Mexico Environment Department Comments on the Bureau of Land Management's Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule, Docket RIN 1004-AE79, Docket No. BLM-2022-0003

NMED is encouraged by and is in general supportive of BLM's proposal to strengthen waste prevention and resource conservation requirements, which have the co-benefit of the protection of public health and welfare. However, without clarification that the proposed standards do not preempt more stringent state standards, they could allow for increased waste in some states, including New Mexico. With such a clarification, the proposed rule(s), once implemented and enforced, will result in significant and meaningful reductions in the waste of natural gas and the emission of air pollutants that negatively impact public health and the environment. These latter co-benefits include a significant reduction in ozone precursor pollutants which will result in lower ozone concentrations, a significant reduction in methane emissions, a potent GHG that contributes to climate change, and a significant reduction in both toxic and hazardous air pollutants, including carcinogens such as benzene. The proposed rule(s) sets achievable, cost-effective, and appropriate waste reduction requirements for the O&G industry; however, NMED defers to EMNRD on how these requirements align with OCD's waste rules. The proposed standards will establish a baseline set of requirements that apply nation-wide and will help to align the varying approaches by states to address emissions from the O&G sector, especially where emissions from one state may impact affected areas in another state.

New Mexico is the second largest oil producing state and shares borders with multiple O&G producing states, including Texas, the largest oil producing state in the U.S. According to the BLM, methane emissions from the upstream O&G sector represent a significant portion of the U.S. GHG emissions profile. New Mexico's own emissions inventory estimates that emissions from the O&G sector make up 53% of the state's GHG emissions and 64% of the total state-wide methane emissions. Over the last two years, NMED and EMNRD developed an enforceable strategy to eliminate unnecessary waste from the O&G sector while simultaneously reducing ozone precursors and methane emissions. Similarly, the BLM's proposal will ensure consistent regulation of the O&G industry on a national level, which is crucial to reduce waste of a natural resource, protect public health and the environment, combat climate change, and provide an equitable and enforceable national regulatory framework.

General Comments for Consideration

<u>I. The proposed rule supports New Mexico's efforts to reduce VOC and GHG emissions that contribute to unhealthy ozone levels and contribute to climate change.</u>

Several ozone monitors in New Mexico show that air quality is approaching or exceeding the 2015 ozone National Ambient Air Quality Standard (NAAQS). The Sunland Park area in southern New Mexico is currently designated as in nonattainment of the 2015 ozone NAAQS, with an additional seven counties in the state monitoring ozone concentrations at or above 95% of the standard. Monitored ozone concentrations increased throughout New Mexico over the last several years, including both of New Mexico's oil and natural gas producing regions in the San Juan and Permian Basins. According to the EPA's latest National Emissions Inventory (EPA, 2014 NEI version II), over 80% of the emissions in these areas are from oil and natural gas sources. The Carlsbad ozone air monitor (AQS ID # 35-015-1005) in the Permian Basin, which is an area of rapid growth in oil production, serves as a prime example of the air pollution problems facing New Mexico. The design value for ozone at this monitor has elevated from 68 ppb in 2016 to 78 ppb in 2020. 2021 data show some of the highest monitored ozone concentrations recorded in the past decade, indicating this upward trend will continue throughout the state.

To improve air quality in these areas, NMED developed the Ozone Attainment Initiative (OAI) and joined the EPA's Ozone Advance program. As part of the OAI, NMED is currently researching options for control measures for all source sectors. The BLM's proposed rule will have the secondary benefit of reducing emissions from the oil and gas sector. Without these important reductions, additional counties in New Mexico and other states may exceed the 2015 ozone NAAQS, resulting in additional nonattainment area designations and nonattainment permitting requirements.

Recent photochemical modeling indicates that interstate transport contributes to high ozone concentrations in New Mexico. As a result, New Mexico faces nonattainment designations and increased nonattainment permitting requirements, while several states contributing to these exceedances have taken no action to address their contributions. This further emphasizes the secondary benefit from reducing emissions from the O&G sector in basins that span state lines.

II. Robust, effective, and recurring fugitive emissions monitoring is critical to ensuring compliance with the proposed rules and ensuring durable long-lasting emissions reductions. NMED encourages the BLM to consider innovative fugitive monitoring methods to determine compliance with the proposed rule requirements.

NMED strongly urges the BLM to authorize the use of next generation tools to monitor the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. There are several innovative compliance approaches that can be used to effectively and efficiently monitor sources for compliance. Given the magnitude of affected sources that will be brought under the rule, BLM should consider allowing technologies that provide quantifiable, verifiable, and consistent monitoring and compliance data at a scale that can accommodate large remote regional areas consisting of hundreds or even thousands of facilities. Remote sensing technologies may allow owners and operators to more effectively comply with the monitoring requirements at well pads, without impacting the accuracy of the compliance determination. As further noted, other innovative remote sensing technologies to monitor fugitive and large emission events could include aerial, truck-based, satellite, and continuous monitoring. NMED supports these innovative approaches and has provided a mechanism for their use in New Mexico's ozone precursor pollutants from the oil and gas sector (20.2.50 NMAC or Part 50) rules. Alternative monitoring strategies must be effective, enforceable, and equivalent and will be a critical option for ensuring that emission leaks are identified and repaired as required.

III. **NMED urges the BLM to include other innovative compliance and enforcement strategies and tools that provide an effective and efficient means of determining compliance and enforcing rule provisions.**

The proposed rules are likely to affect thousands of sources in New Mexico. Given the size and scope of the affected sources, it's critical that the rule contain new approaches to determining compliance with the rule provisions. Providing effective, efficient, and innovative methods to determine overall rule compliance will assist state agencies that have limited capacity and resources, will result in better rates of compliance across the industry, and will improve the overall ability of regulatory agencies to enforce on violations of the rule.

NMED's Part 50 rules allow for agency-approved alternative monitoring plans to address equipment leak requirements through equally effective methods, incenting industry, spurring technology development, and reducing waste. The rule allows NMED to terminate such a plan if it finds the owner or operator failed to comply with any of the plan's provisions and did not promptly notify NMED. Similarly, BLM should follow NMED's rules embrace of fuel cells as an air pollution control device, a climate and air quality solution which also reduces waste.

Like NMED's Part 50 rules, BLM should establish that violations of the proposal are prohibited activities and provide that credible evidence obtained by the agency or provided by a third party may be used as a basis for establishing whether a violation occurred.

Effective, efficient and innovative compliance and enforcement strategies will improve overall rates of compliance, reduce waste and harmful air pollution, and improve overall air quality and impacts on public health and the environment. Strategies could include the preparation and submittal of annual compliance certifications identifying specific areas of compliance and noncompliance with rule provisions and third-party audits of an operator's compliance with the rule, including the effectiveness of the operator's Leak Detection and Repair (LDAR) program.

Comment on the proposed rule requirements

NMED recommends that the BLM establish an applicability threshold for new and existing storage vessel control requirements similar to the threshold adopted by the EPA.

Storage vessels and tank batteries are a significant source of VOC and methane emissions from the O&G sector. The BLM should consider establishing a threshold to include lower emitting storage vessels and tank batteries and provide sufficient time for owners and operators to comply with the control requirements as part of a phased compliance timeline. During New Mexico's Part 50 rulemaking hearing affected owners and operators and industry stakeholders raised concerns about having sufficient numbers of control devices available to implement controls simultaneously. To address this, Part 50 proposes a phased compliance deadline in order to ensure there are sufficient control devices available over the course of the compliance timeline. Lower applicability thresholds for both new and existing vessels with a reasonable compliance deadline will result in important additional emissions reductions from the affected sources.

ATTACHMENT B - EXHIBIT 1

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, 08/05/2022]

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 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, 08/05/2022]

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, 08/05/2022]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, 08/05/2022]

20.2.50.5 EFFECTIVE DATE: August 05, 2022, except where a later date is specified in another section.
[20.2.50.5 NMAC - N, 08/05/2022]

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, 08/05/2022]

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. Definitions beginning with the letter "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.

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

C. Definitions beginning with the letter "C":

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

(2) "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.

(3) "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.

(4) "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.

(5) "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.

(6) "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.

(7) "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.

(8) "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.

D. Definitions beginning with the letter "D":

(1) "Department" means the New Mexico environment department.

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

(3) "Downtime" means the period of time when equipment is not in operation.

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

(5) "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.

E. Definitions beginning with the letter "E":

(1) "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.

(2) **"Existing"** means constructed or reconstructed before the effective date of this Part.

F. Definitions beginning with the letter "F":

(1) **"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.

(2) **"Flowback vessel"** means a vessel that contains flowback.

G. Definitions beginning with the letter "G". [RESERVED]

(1) **"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.

(2) **"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.

H. Definitions beginning with the letter "H":

(1) **"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.

(2) **"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.

(3) **"Hydraulic refracturing"** means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

(4) **"Hydrocarbon liquid"** means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.

I. Definitions beginning with the letter "I":

(1) **"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.

(2) **"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.

(3) **"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.

J. Definitions beginning with the letter "J". [RESERVED]

K. Definitions beginning with the letter "K". [RESERVED]

L. Definitions beginning with the letter "L":

(1) **"Liquid unloading"** means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

(2) **"Liquid transfer"** means the unloading of a hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport.

(3) **"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.

(4) **"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.

M. Definitions beginning with the letter "M". [RESERVED]

N. Definitions beginning with the letter "N". **"non-porous"** means multi-use items such as metal, glass and plastic;

(1) **"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.

(2) **"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.

(3) **"New"** means constructed or reconstructed on or after the effective date of this Part.

(4) **"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.

O. Definitions beginning with the letter "O":

(1) **"Occupied area"** means the following:

(a) 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;

(b) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities;

(c) 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

(d) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or similar place of outdoor public assembly.

(2) **"Operator"** means the person or persons responsible for the overall operation of a stationary source.

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

(4) **"Owner"** means the person or persons who own a stationary source or part of a stationary source.

P. Definitions beginning with the letter "P":

(1) **"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.

(2) **"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.

(3) **"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.

(4) **"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.

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

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

(7) **"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.

Q. **Definitions beginning with the letter "Q"**. **"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.

R. Definitions beginning with the letter "R":

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

(2) **"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.

(3) **"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.

(4) **"Responsible official"** means one of the following:

(a) 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.

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

(5) **"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.

S. Definitions beginning with the letter "S":

(1) **"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.

(2) **"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."

(3) **"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.

(4) **"Startup"** means the setting into operation of air pollution control equipment or process equipment.

(5) **"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.

(6) **"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.

T. Definitions beginning with the letter "T":

(1) **"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.

(2) **"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.

(3) **"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.

U. Definitions beginning with the letter "U". [RESERVED]

V. **Definitions beginning with the letter "V": "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.

W. Definitions beginning with the letter "W":

(1) **"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.

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

(3) **"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, 08/05/2022]

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, 08/05/2022]

20.2.50.9 **CONSTRUCTION:** This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, 08/05/2022]

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, 08/05/2022]

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, 08/05/2022]

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, 08/05/2022]
[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, 08/05/2022]

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 Paragraph (1) of Subsection A of 20.2.50.112 NMAC 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 Paragraph (2) of Subsection A of 20.2.50.112 NMAC 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, 08/05/2022]

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: 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:

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

(b) 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.

(c) 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.

(d) 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:

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

Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)

$$\text{Load (Hp)} = \frac{}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

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, 08/05/2022]

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 NMAC - N, 08/05/2022]

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 Items (i) and (ii) of Subparagraph (c) 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 Item (ii) of Subparagraph (c) 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 Subparagraph (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 NMAC - N, 08/05/2022]

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: thirty percent by January 1, 2024; sixty-five percent by January 1, 2025; and one-hundred percent 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, 08/05/2022]

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, 08/05/2022]

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, 08/05/2022]

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, 08/05/2022]

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, 08/05/2022]

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, 08/05/2022]

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 tables 1 and/or 2 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) 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, 08/05/2022]

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/or 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) ofSubsection 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, 08/05/2022]

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 ofthe 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.

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, 08/05/2022]

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, 08/05/2022]

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 and/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, 08/05/2022]

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

applifollowing:

and

including the

(d) the date and duration of any period where the control device was not operating;

(e) records of the inspections required in Subsection C of 20.2.50.127 NMAC,

(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, 08/05/2022]

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, 08/05/2022]

HISTORY OF 20.2.50 NMAC: [**RESERVED**]