COLORADO
Air Quality Control Commission
Department of Public Health & Environment

NOTICE OF RULEMAKING HEARING

Regarding proposed revisions to:

Regulation Number 7 and Regulation Number 22
5 CCR 1001-9 and 5 CCR 1001-26

SUBJECT:
The Air Quality Control Commission will hold a rulemaking hearing to consider revisions to Regulation Number 7 and Regulation Number 22 to address legislative and policy directives, that: reduce emissions from the upstream and midstream segments of the oil and gas industry as identified in the oil and gas sector and industrial sector of the Greenhouse Gas (GHG) Roadmap, including potential requirements for Leak Detection and Repair, natural gas processing plants, pigging and blowdown system maintenance operations, midstream fuel combustion equipment, well maintenance operations, and upstream GHG intensity; impose additional practices to ensure the efficacy of air pollution control equipment; impose additional reporting requirements to ensure the verifiability and enforceability of the regulatory requirements; and achieve reductions of GHG and co-pollutants in disproportionately impacted communities.

These revisions to Regulation Numbers 7 and 22 are currently proposed on a state-wide and state-only basis, but the Commission may consider State Implementation Plan (SIP) revisions to Regulation Number 7, specific to flare performance, as necessary to address Ozone Nonattainment Area requirements related to previously submitted SIP revisions. Further, these revisions will include any typographical, grammatical and formatting errors throughout each of the regulations. Alternative proposals to achieve additional GHG reductions or compliance verification from sources and source categories affected by the Division's proposal may also be considered.

All required documents for this rulemaking can be found on the Commission website at: https://cdphe.colorado.gov/aqcc

PUBLIC COMMENT SESSION
DATE: December 14, 2021
TIME: 4:30 p.m. to 7:30 p.m.
PLACE: The hearing will be held online only; there will be no in-person participation. Details related to participation and registration can be found at: https://cdphe.colorado.gov/aqcc
NOTE: The public comment session may end early if all commenters that are registered and in attendance before 6:30 have had an opportunity to speak prior to 7:30.

PARTY TESTIMONY & DELIBERATIONS
DATE: December 15-17, 2021
TIME: To begin at or after 9:00 a.m.
PLACE: The hearing will be held online only; there will be no in-person participation. Details related to participation and registration can be found at: https://cdphe.colorado.gov/aqcc
NOTE: No additional public comment will be taken during this time.

IMPORTANT: As Colorado begins to re-open from COVID-19, the Commission may reestablish conducting meetings at the Colorado Department of Public Health and Environment in its entirety or structured as a hybrid meeting. Any such changes will be noticed on the Commission's website at: https://cdphe.colorado.gov/aqcc

The hearing may be continued at such places and time as the Commission may announce. Any such changes will be noticed on the Commission's website. Interested parties may contact the Commission Office at cdphe.aqcc-comments@state.co.us to confirm meeting details.

PUBLIC COMMENT:

The Commission encourages input from the public, either orally during the public comment session or in writing prior to the hearing. However, oral public comment will generally not be permitted by persons who offer comment on behalf of an entity that is a party. Those persons may, however, submit written public comment. Instructions for registering to provide oral public comment will be posted in the agenda on the Commission's website at https://cdphe.colorado.gov/aqcc on December 3, 2021.

Written comments should be submitted no later than **November 30, 2021** by emailing cdphe.aqcc-comments@state.co.us or mailing to:

Colorado Air Quality Control Commission
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South, EDO-AQCC-A5
Denver, Colorado 80246

IMPORTANT DATES AND DEADLINES:

PROCESS DESCRIPTION	DUE DATE & TIME	NOTES
Request for Party Status	October 12, 2021 by 5:00 p.m.	Additional information below
Status Conference	October 14, 2021 at 8:00 a.m.	Virtual Meeting or as noticed on the Commission website at: https://cdphe.colorado.gov/aqcc
Alternate Proposal	October 28, 2021 by 11:59 p.m.	Additional information below
Prehearing Statement	October 28, 2021 by 11:59 p.m.	Additional information below
Prehearing Conference	November 10, 2021 at 1:00 p.m.	Virtual Meeting or as noticed on the Commission website at: https://cdphe.colorado.gov/aqcc
Rebuttal Statement	November 22, 2021 by 12:00 p.m.	Additional information below
Written Public Comments	November 30, 2021 by 11:59 p.m.	Additional information above

Submittals for this hearing should be emailed to cdphe.aqcc-comments@state.co.us unless an exception is granted pursuant to Subsection III.I.3. of the Commissions Procedural Rules.

REQUEST FOR PARTY STATUS:
A request for party status must:

1) identify the applicant (this could be a company and/or contact name);
2) provide the name, address, telephone and email address of the applicant's representative or counsel; and
3) briefly summarize what, if any, policy, factual, and legal issues the applicant has with the proposal(s) as of the time of filing the application.

In addition, requests for party status should indicate whether the applicant intends to file an alternate proposal and, if so, describe the scope and nature of the alternate proposal.

The request for party status must be electronically mailed to:

- Air Quality Control Commission staff: theresa.martin@state.co.us
- Air Quality Control Commission attorney: tom.roan@coag.gov
- Air Pollution Control Division staff: stefanie.rucker@state.co.us
- Air Pollution Control Division attorney: jackie.calicchio@coag.gov

Requests received beyond the stated deadline shall only be considered upon a written motion for good cause shown. The Commission reserves the right to deny party status to anyone that does not comply with the Commission's Procedural Rules.

STATUS CONFERENCE:
Attendance at the status conference is mandatory for anyone who has requested party status, though each party need only have one representative present. The status conference is intended to ascertain and discuss the issues involved, and to ensure that parties are making all necessary efforts to discuss and resolve such issues prior to the submission of prehearing statements. Parties will be confirmed and a party list will be generated and distributed. The status conference will be held virtually via video conference. A registration link will be provided by the Commission's office prior to the status conference. Note that if the Hearing Officer deems the status conference unnecessary, the status conference may be cancelled. Concerns about the scope of alternate proposals as described in a request for party status should be raised at the status conference.

ALTERNATE PROPOSAL:
Alternate proposals will be considered by the Commission "only if the subject matter of the alternative proposal is consistent with and fits within the scope of the notice." 5 CCR § 1001-1, Section (V)(E)(4)(b). The submittal of an alternate proposal must be accompanied by a separate electronic copy of the alternate proposed rule and statement of basis and purpose language and all other associated documents as required by the Commission's Procedural Rules, including an economic impact analysis. Alternate proposals and associated exhibits must be emailed to all persons listed on the party status list or otherwise provided through an approved method of electronic transmission. Alternate proposals that do not comply with this Notice and the Commission's Procedural Rules will not be considered by the Commission.

PREHEARING STATEMENTS:
Each party and the Division must submit a prehearing statement. Exhibits to a prehearing statement must be submitted in a separate electronic transmission. Prehearing statements and associated exhibits must be emailed to all persons listed on the party status list or otherwise provided through an approved method of electronic transmission. Prehearing statements must contain all the necessary elements described in subsection V.E.6.c of the Commission's Procedural Rules (5 CCR § 1001-1).

PREHEARING CONFERENCE:
Attendance at the prehearing conference is mandatory for all parties to this hearing, though each party need only have one representative present. The prehearing conference will be held virtually, and registration information will be provided by the Commission's office prior to the prehearing conference.

REBUTTAL STATEMENTS:
Rebuttal statements may be submitted by the Division and any party to the hearing to respond to issues and arguments identified in prehearing statements. Rebuttal statements may not raise any issues, or be accompanied by alternate proposals, that could have been raised in the party's prehearing statement. Rebuttal statements and associated exhibits must be emailed to all persons listed on the party status list or otherwise provided through an approved method of electronic transmission. The filing of rebuttal statements is optional.

DELIBERATION AND FINAL ACTION:
The Commission intends to deliberate and take final action on the proposed changes to these Regulations at the conclusion of the testimony.

STATUTORY AUTHORITY FOR THE COMMISSION'S ACTIONS:
The Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq. (the State Air Act or the Act), specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere and provides the Commission broad authority to regulate air pollutants.

Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Pursuant to HB 21-1266, the Commission must, by January 1, 2022, adopt regulations to ensure that the state meets its greenhouse gas reduction targets for the oil and gas sector (36% by 2025 and 60% by 2030). The Commission must also ensure that industrial sector emissions (including those from oil and gas fuel combustion equipment) are reduced by 20% from the 2015 baseline by 2030. These revisions will, taking into account other relevant laws and rules (including the revisions to Regulation Numbers 7 and 22 adopted as part of this rulemaking action), as well as voluntary actions taken by local communities and the private sector, achieve the state's GHG reduction goals through 2030 for the oil and gas industry.

The rulemaking hearing will be conducted in accordance with Sections 24-4-103 and 25-7-110, 25-7-110.5 and 25-7-110.8 C.R.S., as applicable and amended, the Commission's Procedural Rules, all other applicable rules and regulations, and as otherwise stated in this notice. This list of statutory authority is not intended as an exhaustive list of the Commission's statutory authority to act in this matter.

Dated this 20th day of September 2021 at Denver, Colorado

Colorado Air Quality Control Commission

Jeremy Neustifter, Administrator

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

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

5 CCR 1001-9

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

Outline of Regulation

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II. (State Only) Statewide Controls for Oil and Gas Operations

III. ~~(State Only)~~ Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

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

PART F Statements of Basis, Specific Statutory Authority and Purpose

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

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PART D Oil and Natural Gas Operations

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II. (State Only) Statewide Controls for Oil and Gas Operations

II.A. (State Only) Definitions

II.A.1. -"Air Pollution Control Equipment," as used in this Section II., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section II.B.2.e.

II.A.2. "Approved Instrument Monitoring Method," means an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring method or program. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations, including approved instrument monitoring method and/or AVO inspections.

II.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions.

II.A.4. "Blowdown" as used in Section II.H., means the depressurization of equipment to reduce system pressure for shutdowns or for maintenance, safety, or cessations of operations. Blowdown includes venting as defined in Section II.C.2.a.(i)(B) where the venting was intentional.

II.A.~~4~~5. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

II.A.~~5~~6. "Class II Disposal Well Facility" means a facility that injects underground fluids which are brought to the surface in connection with natural gas storage operations or oil or natural gas production and that may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Class II disposal well facilities do not include wells which inject fluids for enhanced recovery of oil or natural gas or for storage of hydrocarbons which are liquid at standard temperature and pressure.

II.A.~~6~~7. "Commencement of ~~o~~Operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

II.A.~~7~~8. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

II.A.~~8~~9. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

II.A.10. "Disproportionately Impacted Community" (DI community) means a community that is in a census block group, as determined in accordance with the most recent United States census, where the proportion of households that are low income (meaning the median household income is less than or equal to two hundred percent of the federal poverty guideline) is greater than forty percent; the proportion of households that identify as minority is greater than forty percent, or the proportion of households that are housing cost-burdened (meaning a household that spends more than thirty percent of its income on housing) is greater than forty percent; or is any other community as identified or approved by a state agency, if: the community has a history of environmental racism

perpetuated through redlining, anti-indigenous, anti-immigrant, anti-Hispanic, or anti-black laws; or the community is one where multiple factors, including socioeconomic stressors, disproportionate environmental burdens, vulnerability to environmental degradation, and lack of public participation, may act cumulatively to affect health and the environment and contribute to persistent disparities.

II.A.~~9~~11. "Dump Valve" means a liquid-control valve in a separator that controls liquid level within the separator vessel.

II.A.~~10~~12. "Dump Event" means the opening of a dump valve allowing liquid to flow from a separator equipped with a dump valve to a storage tank.

II.A.~~11~~13. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

II.A.~~12~~14. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

II.A.~~13~~15. "Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.

II.A.16. "Hot Tapping" means a procedure that makes a new pipeline connection while the pipeline remains in service, flowing natural gas under pressure. The procedure involves attaching a branch connection and valve on the outside of an operating pipeline and then cutting out the pipe-line wall within the branch and removing the wall section through the valve.

II.A.17. "Jumper Line" means an enclosed piping system attached to the vent line of a pig launcher or receiver that routes the contents of a pig launcher or receiver into a lower pressure gathering system.

II.A.18. "Midstream Pipeline" means the pipeline and metering and regulating equipment delivering oil or natural gas from an oil or gas well or well production facility to a natural gas compressor station, natural gas processing plant, transmission pipeline, or direct use. Midstream pipeline also means the pipeline and metering and regulating equipment delivering oil or natural gas from a natural gas compressor station to a natural gas processing plant, transmission pipeline, or direct use.

II.A.19. "Midstream Segment" means the oil and natural gas compression segment and the natural gas processing segment upstream of the natural gas transmission and storage segment.

II.A.~~14~~20. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

II.A.21. "Natural Gas Processing Segment" means the operations engaged in the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.

II.A.22. "Natural Gas Transmission and Storage Segment" means onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015), that are physically located in Colorado.

II.A.~~15~~23. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

II.A.24. "Northern Weld County" means the portion of the county that does not lie south of a line described as follows: Beginning at a point on Weld County's eastern boundary and Logan County's western boundary intersected by 40 degrees, 42 minutes, 47.1 seconds north latitude, proceed west on 40 degrees, 42 minutes, 47.1 seconds north latitude until this line intersects Weld County's western boundary and Larimer County's eastern boundary.

II.A.~~16~~25. "Occupied Areas" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

II.A.26. "Oil and Natural Gas Compression Segment" means the gathering pipelines and other equipment used to collect oil and/or natural gas from gas or oil wells and used to compress, dehydrate, sweeten, or transport the oil and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or to a natural gas distribution pipeline. For purposes of Section II., equipment located within the boundaries of a well production facility, including but not limited to compressors, is excluded from the oil and natural gas compression segment.

II.A.~~17~~27. "Open-Ended Valve or Line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

II.A.28. "Pig Ramp" means a device installed inside the barrel of a pig receiver designed and intended to prevent liquid accumulation in the barrel and minimize release of volatile liquids into the environment during retrieval of the pig.

II.A.29. "Pigging" means the process of introducing and subsequently removing a specialized device (a "pig") into a natural gas pipeline to push liquids through the pipeline into a slug catcher and/or designated system.

II.A.30. "Pigging Facility" means the upstream or downstream facility where a pig is launched or received, including standalone pigging stations, natural gas compressor stations, natural gas processing plants, well sites, or well production facilities.

II.A.31. "Pigging Pipeline" means a midstream segment pipeline connected to a pig launcher or receiver.

II.A.~~18~~32. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

II.A.~~19~~33. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

II.A.~~20~~34. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

II.A.~~21~~35. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

II.A.~~22~~36. "Storage Tank Measurement System" means equipment and methods used to determine the quantity and quality of the liquids inside a storage tank without requiring direct access through the storage tank thief hatch.

II.A.~~23~~37. "Storage Vessel" means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

II.A.~~25~~38. "Vapor Collection and Return System" means a closed system designed to control the release of VOCs displaced from a vessel during transfer of hydrocarbon liquids by using the transferred hydrocarbon liquids for direct displacement to force vapors from the vessel being loaded into either the storage tank being unloaded or to air pollution control equipment.

II.A.~~24~~39. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation, pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor.

II.A.~~26~~40. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

II.B. (State Only) General Provisions

II.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations~~,~~; Class II disposal well facilities~~,~~; well production facilities~~,~~; and midstream segment operations, including natural gas compressor stations~~,~~ and natural gas processing plants.

II.B.1.a. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

II.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

II.B.2. General requirements for air pollution control equipment used to comply with Section II.

II.B.2.a. All air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance

practices. The owner or operator must keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of VOCs and other hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

II.B.2.b. If a combustion device is used to control emissions of VOCs and other hydrocarbons, it must be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

II.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

II.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons must be equipped with and operate an auto-igniter as follows

II.B.2.d.(i) All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device.

II.B.2.d.(ii) All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

II.B.2.e. Alternative emissions control equipment will qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section II., if the Division approves the equipment, device, or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section II.

II.B.2.f. Owners or operators must conduct weekly visual inspections of air pollution control equipment.

II.B.2.f.(i) Visual inspections must begin

II.B.2.f.(i)(A) February 14, 2022, for owners or operators of storage tanks subject to Section II.C.1.

II.B.2.f.(i)(B) May 1, 2022, for air pollution control equipment that commenced operation before February 14, 2022, unless subject to Section II.B.2.f.(i)(A).

II.B.2.f.(i)(C) Within thirty (30) days of commencement of operation for air pollution control equipment constructed on or after February 14, 2022.

II.B.2.f.(ii) Weekly visual inspections must include, at a minimum

II.B.2.f.(ii)(A) Inspection or monitoring of each combustion device to ensure that it is operating, including that the pilot light is lit and the auto-igniter is properly functioning.

II.B.2.f.(ii)(B) Inspection or monitoring of each combustion device to ensure that the valves for the piping of gas to the pilot light are open and functioning properly.

II.B.2.f.(ii)(C) Inspection or monitoring of each combustion device to ensure the burner tray is not visibly clogged.

II.B.2.f.(ii)(D) Inspection of each combustion device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

II.B.2.f.(ii)(E) Inspection or monitoring of each vapor recovery unit to ensure that the unit is operating and that vapors are being routed to the unit.

II.B.2.f.(ii)(F) Inspection or monitoring of air pollution control equipment to ensure that valves for the piping of gas to the air pollution control equipment are open.

II.B.2.f.(ii)(G) Recording the flow meter readings, once installed pursuant to Section II.B.2.g.(i). An owner or operator may use automation to continuously record flow to the air pollution control equipment for which flow meters are required under Section II.B.2.g.

II.B.2.g. Owners or operators must install and operate a flow meter at the inlet to the air pollution control equipment.

II.B.2.g.(i) Flow meters must be installed and operating by

II.B.2.g.(i)(A) May 1, 2022, for air pollution control equipment that commenced operation before February 14, 2022.

II.B.2.g.(i)(B) Commencement of operation for air pollution control equipment that commences operation on or after February 14, 2022.

II.B.2.g.(ii) The owner or operator must calibrate and maintain the flow meter in accordance with the manufacturer's specifications and schedule.

II.B.2.g.(iii) Flow meters are not required to be installed

II.B.2.g.(iii)(A) On portable air pollution control equipment used at a location for less than 180 consecutive days.

II.B.2.g.(iii)(B) On vapor recovery units used in connection with separation equipment or dehydrators, or on air pollution control equipment used during vapor recovery unit downtime associated with dehydrators.

II.B.2.g.(iii)(C) Where installation of the flow meter is technically or economically infeasible, as demonstrated by the owner or operator to the Division's reasonable satisfaction, or where the Division approves the use of an alternate parameter (and associated recordkeeping and reporting).

II.B.2.h. Beginning February 14, 2022, the owner or operator must conduct performance tests for each enclosed combustion device for which Regulation Number 7 requires the device to achieve at least 95% control efficiency for hydrocarbons. A performance test that does not demonstrate that an enclosed combustion device

is achieving at least 95% control efficiency for hydrocarbons is considered a failing test.

II.B.2.h.(i) Performance test requirements.

II.B.2.h.(i)(A) Performance tests are not required for enclosed combustion devices serving solely as control devices during vapor recovery unit downtime.

II.B.2.h.(i)(B) Owners or operators must test all enclosed combustion devices used to control the same piece of equipment or operation (e.g., a bank of enclosed combustion devices controlling a storage tank) over the course of the same testing event, which may occur over multiple working days.

II.B.2.h.(i)(C) Performance tests must be conducted in accordance with a Division-approved test protocol.

II.B.2.h.(i)(D) For the calendar year of the performance test, owners or operators must calculate enclosed combustion device emissions (or the emissions for the source controlled) pursuant to Sections II.G. and V. with the results of the most recent performance test.

II.B.2.h.(i)(E) Owners or operators of enclosed combustion devices that fail a performance test must follow the manufacturer's repair instructions, if available, or best combustion engineering practices to return the device to compliant operation within thirty (30) days or shut-in all equipment or operations controlled by the enclosed combustion device.

II.B.2.h.(i)(F) Owners or operators must retest the enclosed combustion device within ninety (90) days of a failed test or upon return to operation if the equipment or operations controlled by the enclosed combustion device were shut-in as a response to a failed test.

II.B.2.h.(i)(G) As an alternative to Section II.B.2.h.(i)(F), the owner or operator may replace the failing enclosed combustion device with a different enclosed combustion device and test the replacement enclosed combustion device upon commencement of operation. The owner or operator does not have to test the replacement enclosed combustion device if the device is newly manufactured (has never been in operation anywhere else) and has been tested by the manufacturer in accordance with the requirements of 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(d) (June 3, 2016).

II.B.2.h.(ii) Initial performance test schedule.

II.B.2.h.(ii)(A) Enclosed combustion devices that commenced operation before December 31, 2021, must be tested within the schedule in Table 1, unless the Division approves an alternative testing schedule.

Table 1 – Enclosed Combustion Device Inspections						
Location of enclosed combustion	Compliance deadlines					
	Dec. 31,	Dec. 31,	Dec. 31,	Dec. 31,	Dec. 31,	Dec. 31,

device	2022	2023	2024	2025	2026	2027
	Percentage (%) of enclosed combustion devices that must be tested					
Within a DI community	At least 25%	At least 50%	At least 75%	At least 100%	NA	NA
Within the 8-hour ozone control area and northern Weld County	At least 20%	At least 40%	At least 60%	At least 80%	100%	NA
Outside the 8-hour ozone control area and northern Weld County	At least 10%	At least 20%	At least 35%	At least 50%	At least 75%	100%

II.B.2.h.(ii)(B) Enclosed combustion devices that commence operation on or after December 31, 2021, must be tested within two (2) years after commencement of operation, unless the enclosed combustion device is newly manufactured (has never been in operation) and has been tested by the manufacturer in accordance with the requirements of 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(d) (June 3, 2016), in which case the enclosed combustion device must be tested within five (5) years after commencement of operation.

II.B.2.h.(ii)(C) No enclosed combustion device located in the 8-hour ozone control area and northern Weld County or in a disproportionately impacted community can operate for more than five (5) years without a performance test.

II.B.2.h.(ii)(D) No enclosed combustion device located outside the 8-hour ozone control area and northern Weld County but not within a disproportionately impacted community can operate for more than ten (10) years without a performance test.

II.B.2.h.(ii)(E) Owners or operators do not have to start up a source solely to perform a performance test on the enclosed combustion device if gas flow to the device is from a source or equipment that has been shut-in for more than thirty (30) consecutive days; however, a performance test is required within thirty (30) days of the enclosed combustion device once again receiving gas flow.

II.B.2.h.(iii) Notification. No later than July 31, 2022, owners or operators of enclosed combustion devices subject to Section II.B.2.h.(ii) must submit a notification to the Division with the following information.

II.B.2.h.(iii)(A) A list of all enclosed combustion devices that commenced operation before December 31, 2021, with associated facility name and location, AIRS ID (if assigned), manufacturer model, serial number (if available), and identification of equipment controlled by the enclosed combustion device.

II.B.2.h.(iii)(B) The year in which each enclosed combustion device will be tested to meet the compliance schedule in Table 1.

II.B.2.h.(iv) Subsequent performance tests.

II.B.2.h.(iv)(A) Enclosed combustion devices located in the 8-hour ozone control area and northern Weld County must be tested within five (5) years following the previous performance test, unless the enclosed combustion device is newly manufactured (has never been in operation) and has been tested by the manufacturer in accordance with the requirements of 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(d) (June 3, 2016), in which case the enclosed combustion device must be tested within eight (8) years following the previous performance test.

II.B.2.h.(iv)(B) Enclosed combustion devices located within a disproportionately impacted community must be tested within five (5) years following the previous performance test, unless the enclosed combustion device is newly manufactured (has never been in operation) and has been tested by the manufacturer in accordance with the requirements of 40 CFR Part 60, Subpart OOOOa, Section 60.5413a(d) (June 3, 2016), in which case the enclosed combustion device must be tested within eight (8) years following the previous performance test.

II.B.2.h.(iv)(C) Enclosed combustion devices located outside the 8-hour ozone control area and northern Weld County and not within a disproportionately impacted community must be tested within ten (10) years following the previous performance test.

II.B.2.i. Recordkeeping. Except as specified in Section II.B.2.i.(ix), the owner or operator must maintain records for a period of five (5) years and make them available to the Division upon request, including

II.B.2.i.(i) Notifications submitted in accordance with Section II.B.2.h.(iii).

II.B.2.i.(ii) Records of the make, model, serial number, and AIRS ID (if assigned) of each enclosed combustion device and associated facility name and location.

II.B.2.i.(iii) Records of visual inspections conducted pursuant to Section II.B.2.f., including the time and date of each inspection and a description of any problems observed, description and date of any corrective action(s) taken, and name of employee or third party performing corrective action(s).

II.B.2.i.(iv) Records of the date and result of any EPA Method 22 test or investigation.

II.B.2.i.(v) Records of the date and duration of any period where the air pollution control equipment is not operating.

II.B.2.i.(vi) Monthly records of the total hours the vapor recovery unit is not operating, the total condensate throughput volume, and total condensate throughput volume during the time the vapor recovery unit is not operating.

II.B.2.i.(vii) Records of inlet gas flow rate, as required by Section II.B.2.f.(iii)(G).

II.B.2.i.(viii) Records supporting the delay of any performance test pursuant to Section II.B.2.h.(i)(E).

II.B.2.i.(ix) Records of performance tests must be maintained for the life of the equipment that the enclosed combustion device is used to control

(even if ownership or control of the device is transferred), including manufacturer model and serial number(s) of devices tested; the date of the test; a copy of the test protocol followed; a certification by a responsible official that the performance test was conducted in accordance with a Division-approved test protocol; the enclosed combustion device parameters outlined in the test protocol; and documentation of the methods and results of the test.

II.B.2.j. Reporting. The owner or operator must submit the following information to the Division.

II.B.2.j.(i) Within fourteen (14) days of a failing performance test, the owner or operator must submit a notification of the failing test, including: facility AIRS ID and equipment or operation controlled; the date of test; the results of the test; monthly methane and VOC emission calculations using the test results for the calendar year of the test; monthly production (if enclosed combustion device is controlling a storage tank) or gas flared (if enclosed combustion device is controlling separation equipment) for the calendar year of the test; the proposed corrective action to return the enclosed combustion device to proper operation, including the timing thereof; and the proposed date of the retest.

II.B.2.j.(ii) On the same date at the annual emissions inventory report in Part D, Section V., the owner or operator must submit the date of each performance test, the results of the test, and copies of all performance test reports for testing performed during that year.

II.B.2.j.(iii) By July 31 of each year (beginning 2023), owners or operators must submit an update to the notification provided under Section II.B.2.h.(iii) documenting changes to the list specified in Section II.B.2.h.(iii)(A) (e.g., an enclosed combustion device moved to a different facility (including transfer to another operator) or controlling more or less equipment or operations than specified) and changes to the performance testing schedule provided pursuant to Section II.B.2.h.(iii)(B).

II.B.3. Requirements for compressor seals and open-ended valves or lines

II.B.3.a. Beginning January 1, 2015, each open-ended valve or line at well production facilities and natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line. Alternatively, an open-ended valve or line may be treated as if it is a “component” as defined in Section II.A.7., and may be monitored under the provisions of Section II.E.

II.B.3.b. Beginning January 1, 2015, uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) or 40 CFR Part 60, Subpart OOOOa (June 3, 2016) on that date or thereafter.

II.B.3.c. Beginning January 1, 2015, the rod packing on any reciprocating compressor located at a natural gas compressor station must be replaced every 26,000 hours of operation or every thirty-six (36) months, unless the reciprocating compressor is subject to the reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of 40 CFR Part 60, Subpart OOOO (February 23, 2014) or 40 CFR Part 60, Subpart OOOOa (June 3, 2016) on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

II.B.3.d. Beginning February 14, 2022, the rod packing on any reciprocating compressor located at a natural gas processing plant must be replaced every 26,000 hours of operation or every thirty-six (36) months, unless the reciprocating compressor is subject to the reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of Section I.J.2., 40 CFR Part 60, Subpart OOOO (February 23, 2014), or 40 CFR Part 60, Subpart OOOOa (June 3, 2016) on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on February 14, 2022.

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II.C. Emission reduction from storage tanks at oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.C.1. Control and monitoring requirements for storage tanks

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II.C.1.d. (State Only) Beginning May 1, 2014, or the applicable compliance date in Sections II.C.1.b.(i) or II.C.1.c.(i), whichever comes later, owners or operators of storage tanks subject to Section II.C.1. must conduct audio, visual, olfactory (AVO) and additional visual inspections of the storage tank and any associated equipment (e.g., separator, air pollution control equipment, or other pressure reducing equipment) at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days. Monitoring is not required for storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e. The additional visual inspections must include, at a minimum:

II.C.1.d.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly sealed.

II.C.1.d.(ii) ~~Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment.~~Repealed.

II.C.1.d.(iii) Repealed.~~If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.~~

II.C.1.d.(iv) Repealed.~~Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open.~~

II.C.1.d.(v) Repealed.~~If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.~~

II.C.1.d.(vi) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, visual observation of the dump valve(s) of the last separator(s) before the storage tank(s) to ensure the dump valve is free of debris and not stuck open. The owner or operator is not required to observe the actuation of the dump valve during this inspection; however, if a

dump event occurs during the inspection, the owner or operator must confirm proper operation of the valve.

II.C.1.d.(vii) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, a check for the presence of liquids in liquid knockout vessels that do not drain automatically, underground lines, and aboveground piping.

II.C.1.d.(vii)(A) For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. If liquids are present above the low level indication point, drain liquids.

II.C.1.d.(vii)(B) For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids.

II.C.1.d.(vii)(C) For underground lines and aboveground piping that is not sloped to a liquid knockout or tank and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids and drain liquids as needed.

II.C.1.d.(vii)(D) For underground lines and aboveground piping that is not sloped to a liquid knockout vessel or tank and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids quarterly.

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II.C.2. (State Only) Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections I.D. or II.C.1.

II.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation~~,~~. This requirement does not apply where ~~unless~~ venting is reasonably required for maintenance, unless the control of maintenance emissions is required pursuant to Section II.H.2.; gauging ~~(~~, unless the use of a storage tank measurement system is required pursuant to and the operator ~~compiles~~ complies with Section II.C.4.;~~),~~ or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section II.C.2.b.(ii).

II.C.2.a.(i) Venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which:

II.C.2.a.(i)(A) Are primarily the result of over-pressurization, whether related to design, operation, or maintenance; or

II.C.2.a.(i)(B) Are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole).

II.C.2.a.(ii) When emissions from a controlled storage tank are observed, the Division may require the owner or operator to submit sufficient information demonstrating whether or not the emissions were primarily the result of over-pressurization. Absent a demonstration that such emissions were not primarily the result of over-pressurization, such emissions will be considered venting for purposes of Section II.C.2.a.

II.C.2.a.(iii) When venting is observed, the owner or operator must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. If the venting was observed using an approved instrument monitoring method, the confirmation must be made using an approved instrument monitoring method.

II.C.2.b. Owners or operators of storage tanks subject to the control requirements of Sections I.D., II.C.1.a, II.C.1.b., or II.C.1.c. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section II.C.2.a. Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed.

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II.C.2.b.(ii) Owners or operators must achieve the requirements of Sections II.C.2.a. and II.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule

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II.C.2.b.(ii)(I) Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the inspection frequency in Table ~~1~~2.

Table 2~~1~~ – Storage Tank Inspections

Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Method Inspection Frequency
≥ 2 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

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II.C.3. (State Only) Recordkeeping: The owner or operator of each storage tank subject to Sections I.D. or II.C. must maintain records of STEM, if applicable, including the plan, any updates, and the certification, and make them available to the Division upon request. In addition, for a period of two (2) years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including

II.C.3.a. The AIRS ID for the storage tank.

II.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance (unless the control of maintenance emissions is required pursuant to Section II.H.2.), gauging (unless use of a storage tank measurement system is required pursuant to and the operator complies with Section II.C.4.), or safety of personnel and equipment.

II.C.3.c. The date and duration of any period where the air pollution control equipment is not operating.

II.C.3.d. Records of the inspections required in Sections II.C.1.d. and II.C.2.b.(ii), including the time and date of each inspection and a description of any problems observed, description and date of any corrective action(s) taken, and name of employee or third party performing corrective action(s).

II.C.3.e. Repealed~~Where a combustion device is being used, the date and result of any EPA Method 22 test or investigation pursuant to Section II.C.1.d.(v)~~.

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II.E. (State Only) Leak detection and repair program for well production facilities and natural gas compressor stations

II.E.1. The following provisions of Section II.E. apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

II.E.2. Owners or operators of well production facilities or natural gas compressor stations that monitor components as part of Section II.E. may estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

II.E.3. Beginning January 1, 2015, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method, in accordance with the following schedule

II.E.3.a. Approved instrument monitoring method inspections must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

II.E.3.a.(i) Annual approved instrument monitoring method inspections at natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015. Annual inspections must be conducted through calendar year 2019.

II.E.3.a.(ii) Beginning calendar year 2020, owners or operators of natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must conduct semi-annual approved instrument monitoring method inspections.

II.E.3.b. Approved instrument monitoring method inspections must begin within thirty (30) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than fifty (50) tons per year.

II.E.3.c. Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table ~~2~~3.

II.E.3.d. Beginning January 1, 2023, owners or operators of natural gas compressor stations located within a disproportionately impacted community must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.

II.E.3.~~d~~e. For purposes of Section II.E.3., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table ~~2~~ 3 – Natural Gas Compressor Station Component Inspections	
Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and ≤ 12	Semi-annually
> 0 and < 12, located within a disproportionately impacted community	Quarterly
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.E.4. Requirements for well production facilities

II.E.4.a. Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequencies in Table ~~3~~4.

II.E.4.b. Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within ninety (90) days of the Phase-In Schedule in Table ~~3~~4; within thirty (30) days for well production facilities subject to monthly approved instrument monitoring method inspections; or by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table ~~3~~4.

II.E.4.c. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) but less than or equal to twelve (12) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

II.E.4.d. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) tons per year as calculated in accordance with Section II.E.4.~~e~~g., based on a rolling twelve-month total, and located within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table ~~3~~4.

II.E.4.e. Beginning January 1, 2023, owners or operators of well production facilities located within a disproportionately impacted community must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 4.

II.E.4.f. Owners or operators of well production facilities that commence operation on or after May 1, 2022, must inspect components for leaks using an approved instrument monitoring method at least monthly, unless the owner or operator meets the requirements of Sections II.E.4.f.(i) or (ii), in which case the owner or operator must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 4.

II.E.4.f.(i) The owner or operator installs and operates an automatic pressure management and pilot light system, consistent with a Division-approved protocol, on each storage tank at a well production facility with storage tanks subject to the requirements of Section II.C. The Division-approved protocol must ensure that the automatic pressure management and pilot light system

II.E.4.f.(i)(A) Is capable of continuously tracking the pressure in the storage tank(s) and monitoring the pilot light on combustion devices used as air pollution control equipment;

II.E.4.f.(i)(B) Accurately identifies when storage tank pressure levels both drop and rise substantially to indicate venting (e.g., both when a thief hatch is open and when pressure rises above the level where venting might occur);

II.E.4.f.(i)(C) Accurately identifies when a pilot light is out and subsequently re-lit;

II.E.4.f.(i)(D) Will shut-in flow to the storage tank(s) under the circumstances in Sections II.E.4.f.(i)(B) and II.E.4.f.(i)(C);

II.E.4.f.(i)(E) Triggers a site investigation by the owner or operator upon the occurrence of potential venting and pilot light outages; and

II.E.4.f.(i)(F) Includes sufficient recordkeeping and reporting requirements to demonstrate compliance.

II.E.4.f.(ii) The owner or operator installs and operators an approved air quality monitoring plan pursuant to Section VI. to detect, evaluate, and reduce, as necessary, VOC or methane emissions. Except as further specified in Sections II.E.4.f.(ii)(A) and II.E.4.f.(ii)(B), owners or operators must continue to comply with Sections VI.C.2. and VI.C.3. for as long as the monitoring system is in use.

II.E.4.f.(ii)(A) Owners or operators must keep records of the air quality monitoring plan for as long as the monitoring system is in use and provide records to the Division upon request.

II.E.4.f.(ii)(B) Owners or operators must submit and keep records of the monthly reports of monitoring conducted that meet the requirements of Section VI.C.2.b. for as long as the monitoring system is in use and provide records to the Division upon request.

II.E.4.~~e~~g. The estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at

which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Table 4~~3~~ – Well Production Facility Component Inspections				
Thresholds (per II.E.4.~~d~~g.)				
Well production facilities without storage tanks (rolling twelve-month tpy)	Well production facilities with storage tanks (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and < 2	> 0 and < 2	One time	Monthly	January 1, 2016
≥ 2 and ≤ 12	≥ 2 and ≤ 12	Semi-annually	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area	> 2 and < 12, located within 1,000 feet of an occupied area	Quarterly	Monthly	* begins in 2020
> 2 and < 12, located within a disproportionately impacted community	> 2 and < 12, located within a disproportionately impacted community	Quarterly	Monthly	* begins January 1, 2023
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 12, located within a disproportionately impacted community	> 12, located within a disproportionately impacted community	Monthly		* begins January 1, 2023
> 20	> 50	Monthly		January 1, 2015

II.E.5. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

II.E.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

II.E.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.E.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

II.E.6. Leaks requiring repair: Leaks must be identified utilizing the methods listed in Section II.E.6. Only leaks from components exceeding the thresholds in Section II.E.6. require repair under Section II.E.7.

II.E.6.a. For EPA Method 21 monitoring, at facilities constructed before May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 2,000 parts per million (ppm) not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation, except for well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.b. For EPA Method 21 monitoring, at facilities constructed on or after May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.c. For infra-red camera and AVO monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.d. For other Division approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in the Division's approval.

II.E.6.e. Except as provided in Sections II.E.6.f. or II.E.6.g., for leaks identified using an approved non-quantitative instrument monitoring method or AVO, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.a. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section II.E.6., the leak must be repaired in accordance with Section II.E.7.a. and remonitored in accordance with Section II.E.7.c.

II.E.6.f. Beginning on March 1, 2021, for leaks identified using an approved non-quantitative instrument monitoring method or AVO at a well production facility located within 1,000 feet of an occupied area, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.b. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Sections II.E.6.a. through II.E.6.d., the leak must be repaired as follows and remonitored in accordance with Section II.E.7.c.

II.E.6.f.(i) If EPA Method 21 indicates a leak greater than 500 ppm and less than 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.a.

II.E.6.f.(ii) If EPA Method 21 is not performed or indicates a leak greater than or equal to 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.b.

II.E.6.g. Beginning January 1, 2023, for leaks identified using an approved non-quantitative instrument monitoring method or AVO at a well production facility located within a disproportionately impacted community, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.b. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Sections II.E.6.a. through II.E.6.d., the leak must be repaired as follows and remonitored in accordance with Section II.E.7.c.

II.E.6.g.(i) If EPA Method 21 indicates a leak greater than 500 ppm and less than 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.a.

II.E.6.g.(ii) If EPA Method 21 is not performed or indicates a leak greater than or equal to 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.b.

II.E.7. Repair and remonitoring

II.E.7.a. Except as provided in Section II.E.7.b., the first attempt to repair a leak must be made no later than five (5) working days after discovery and repair of a leak discovered on or after January 1, 2018, completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

II.E.7.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

II.E.7.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

II.E.7.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

II.E.7.a.(iv) Beginning January 1, 2023, the owner or operator must take action(s) where technically feasible to mitigate emissions from leaks placed on delay of repair.

II.E.7.b. For leaks requiring repair pursuant to Sections II.E.6.f. and II.E.6.g., the first attempt to repair must be made as soon as practicable but no later than five (5) working days after discovery and completed within five (5) working days after discovery. If repair is not completed within five (5) working days after discovery, the owner or operator must use other means to stop the leak including, but not limited to, isolating the component or shutting in the well, unless such other means will cause greater emissions.

II.E.7.b.(i) If the owner or operator cannot repair or stop the leak within five (5) working days after discovery, the owner or operator must notify the local government with jurisdiction over the location and the Division as soon as possible, but no later than seven (7) working days after the leak is discovered. The notice must include

II.E.7.b.(i)(A) Identification of the facility, the leaking component, and contact information of the owner or operator representative;

II.E.7.b.(i)(B) The concentration of hydrocarbons using EPA Method 21, if available;

II.E.7.b.(i)(C) Instructions to access the infrared camera video footage of the leak, if available;

II.E.7.b.(i)(D) The approximate distance of the facility to the closest occupied area that is not an outdoor area;

II.E.7.b.(i)(E) The basis for the delay of repair and justification for not isolating the component or shutting in the well; and

II.E.7.b.(i)(F) The estimated date of repair.

II.E.7.c. Within fifteen (15) working days of completion of a repair, the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

II.E.7.d. Leaks discovered pursuant to the leak detection methods of Section II.E.6. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section II.E.7. or keep required records in accordance with Section II.E.8.

II.E.8. Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

II.E.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

II.E.8.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.E.8.c. ~~A~~ For each inspection, a list of the leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak;

II.E.8.d. The date and result of any EPA Method 21 monitoring relied upon to demonstrate a leak is not subject to Section II.E.7.b.;

II.E.8.e. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

II.E.8.f. The date the leak was repaired and for leaks discovered and repaired on or after January 1, 2018, the type of repair method applied;

II.E.8.g. Documentation of actions taken pursuant to Section II.E.7.b. to stop a leak that was not repaired within five (5) working days after discovery or documentation that such actions would cause greater emissions;

II.E.8.h. Copies of all notices submitted pursuant to Section II.E.7.b.(i) and the infrared camera video footage of leaks that required notice pursuant to Section II.E.7.b.(i);

II.E.8.i. The delayed repair list, including the basis for placing leaks on the list;

II.E.8.i.(i) For leaks discovered on or after January 1, 2018, the delayed repair list must include the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

II.E.8.i.(ii) For leaks discovered after March 1, 2021, that require repair pursuant to Section II.E.7.b., the delayed repair list must include the date and duration of leaks for which repairs were not completed within five (5) working days after discovery, and the schedule for repairing the leak.

II.E.8.i.(iii) For leaks discovered after January 1, 2023, pursuant to Section II.E.6.g., that require repair pursuant to Section II.E.7.b., the delayed repair list must include the date and duration of leaks for which repairs were not completed within five (5) working days after discovery, and the schedule for repairing the leak, including, but not limited to, the date upon which necessary parts were ordered and the estimated delivery date.

II.E.8.i.(iv) For leaks discovered after January 1, 2023, the delayed repair list must include a description of action(s) taken to mitigate the emissions from the leak or the reasons why mitigation was not technically feasible, as required under Section II.E.7.a.(iv).

II.E.8.j. The date the leak was remonitored and the results of the remonitoring;

II.E.8.k. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.E.5., an explanation stating why the component is so designated, and the schedule for monitoring such component(s); and

II.E.8.l. Documentation of the owner or operator's proximity analysis, if applicable, including the date of the initial and any subsequent analysis and a description of the methodology used for the analysis.

II.E.9. Reporting. The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must submit a single annual report using the Division-approved format on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year.~~:~~

II.E.9.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

II.E.9.b. The total number of inspections performed per inspection frequency tier of well production facilities, including the number of facilities inspected in accordance with Section II.E.4.d., and inspection frequency tier of natural gas compressor stations;

II.E.9.c. The total number of identified leaks requiring repair, broken out by component type, monitoring method, and inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.d. The total number of leaks repaired for each inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations, and the basis for each delay of repair. This total does not include leaks that have been stopped through other means, as specified in Section II.E.7.b.;

II.E.9.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

II.E.9.g. Each report must be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

II.F. Control of emissions from well production facilities

Well Operation and Maintenance:

II.F.1. On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from commencement of operation by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%.

II.F.2. On or after February 14, 2022, gas coming off a separator, produced during normal operation from any oil and gas well, must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%, unless emitting to the atmosphere is authorized pursuant to a variance issued by the Colorado Oil and Gas Conservation Commission.

II.F.3. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

II.G. (State Only) Emissions during downhole well maintenance, well liquids unloading events, and well plugging

II.G.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with downhole well maintenance, well liquids unloading, and well plugging (beginning January 31, 2020), unless emitting is necessary for safety. The emitting as necessary for safety exemption does not apply to Section II.G.1.c.

II.G.1.a. ~~During~~ Prior to January 1, 2023, during liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without emitting. If these methods are not successful in unloading the liquids from the well, the well may emit in order to create the necessary differential pressure to bring the liquids to the surface.

II.G.1.b. The owner or operator must be present on-site during any planned downhole well maintenance, well liquids unloading, or well plugging event and must ensure that any emissions from the well associated with the event are limited to the maximum extent practicable.

II.G.1.c. Beginning January 1, 2023, owners or operators must use the following best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with all downhole well maintenance and well liquids unloading, including well swabbing, consistent with well site conditions and good engineering practices

II.G.1.c.(i) Use best engineering practices in the design and construction of oil and gas wells and well production facilities to minimize the need for well liquids unloading and other downhole well maintenance as the well ages.

II.G.1.c.(ii) Attempt to create differential pressure to unload the liquids from the well without emitting.

II.G.1.c.(iii) Monitor wellhead pressure and flow rate of the vented natural gas.

II.G.1.c.(iv) Reduce wellhead pressure before releasing gas to the atmosphere.

II.G.1.c.(v) Close wellhead vents to the atmosphere and return the well to normal production operation as soon as practicable.

II.G.1.c.(vi) Use one of the following methods to reduce emissions during well liquids unloading, including well swabbing

II.G.1.c.(vi)(A) Installation and use of artificial lift, such as a plunger lift, with an automated lift controller where automation is technically feasible.

II.G.1.c.(vi)(B) Installation and use of a control device that achieves at least 95% control of hydrocarbon emissions. Portable combustion devices may be used to comply with Section II.G.1.c.(vi)(B).

II.G.2. Recordkeeping

II.G.2.a. Through January 31, 2020, the owner or operator must keep records of the cause, date, time, and duration of venting events under Section II.G. Records must be kept for two (2) years and made available to the Division upon request.

II.G.2.b. Beginning January 31, 2020, or the date specified in Section II.G.2.b.(iii), the owner or operator must keep the following records for two (2) years and make records available to the Division upon request.

II.G.2.b.(i) The cause of emissions (i.e., downhole well maintenance, well liquids unloading, well plugging), date, time, and duration of emissions under Section II.G.

II.G.2.b.(ii) The best management practices used to minimize hydrocarbon emissions or the safety needs that prevented the use of best management practices.

II.G.2.b.(iii) Beginning July 1, 2020, the emissions associated with well liquids unloading, downhole well maintenance, and well plugging.

II.G.2.c. Beginning January 1, 2023, the owner or operator must keep the following records for two (2) years and make records available to the Division upon request.

II.G.2.c.(i) The volume of gas vented during each downhole well maintenance, well liquids unloading, and well plugging event.

II.G.2.c.(ii) The method(s) used to reduce emissions pursuant to Section II.G.1.c.(vi).

II.G.2.c.(iii) For wells with artificial lift, the number of cycles of that lift and the number of well liquids unloading events resulting in emissions.

II.G.3. Reporting

II.G.3.a. The owner or operator must submit a single annual report using a Division-approved format on or before June 30th of each year (beginning June 30th, 2021) that includes the following information regarding each downhole well maintenance, well liquids unloading, and well plugging event conducted the previous calendar year that resulted in emissions.

II.G.3.a.(i) The API number of the well and the AIRS number of any associated storage tanks.

II.G.3.a.(ii) Whether the emissions occurred due to downhole well maintenance, well liquids unloading, or well plugging.

II.G.3.a.(iii) The date, time, and duration of the downhole well maintenance, well liquids unloading, or well plugging event.

II.G.3.a.(iv) The best management practices used to minimize emissions, including the method used pursuant to Section II.G.1.c.(vi) beginning January 1, 2023.

II.G.3.a.(v) Safety needs that prevented the use of best management practices to minimize emissions, if applicable.

II.G.3.a.(vi) An estimate of the volume of natural gas, VOC, NOx, N2O), CO2, CO, ethane, and methane emitted from the well associated with well liquid unloading activities, downhole well maintenance, and well plugging event and the emission factor or calculation methodology used to determine the volume of natural gas and emissions.

II.G.3.a.(vii) Beginning June 30th of 2024 (for calendar year 2023), whether the well identified in Section II.G.3.a.(i) is equipped with artificial lift.

II.H. Emission reduction from midstream segment operations.

II.H.1. Pigging operations

II.H.1.a. Beginning January 1, 2023, midstream segment owners or operators must capture and recover hydrocarbon emissions from pigging operations where owners or operators conduct pigging operations more than one time per month.

II.H.1.a.(i) If capture and recovery of the hydrocarbon emissions emitted during pigging operations is not feasible, the owner or operator may request Division approval to use air pollution control equipment to control hydrocarbon emissions from pigging operations. Such air pollution control equipment is subject to Section II.B.

II.H.1.b. Beginning January 1, 2023, where capture and recovery is not required under Section II.A.1.a., midstream segment owners or operators must use best management practices to reduce emissions associated with pigging operations, including, but not limited to

II.H.1.a.(i) Keeping pipeline access openings to the pig receiver closed at all times except when a pig is being placed into or removed from the receiver or during active pipeline maintenance activities.

II.H.1.a.(ii) Installing a pig ramp inside the pig receiver to prevent liquid accumulation in the pig barrel and minimize the release of volatile liquids during retrieval of the pig.

II.H.1.a.(iii) Where feasible, connecting each high pressure pig launcher and receiver by jumper lines to a low pressure gathering line and operate jumper lines to depressurize such pig launchers and receivers prior to opening the pig launcher or receiver hatch.

II.H.1.a.(iv) Using short pig barrels, which reduce the gas volume for potential release.

II.H.1.a.(v) The Division can approve alternatives to the best management practices in Sections II.H.1.a.(i) through II.H.1.a.(iv) where the owner or operator demonstrates that the alternatives will achieve equivalent or better emission reductions.

II.H.2. Blowdowns

II.H.2.a. Beginning January 1, 2023, midstream segment owners or operators must capture or control hydrocarbon emissions from blowdowns of equipment and piping at natural gas compressor stations and natural gas processing plants. Air pollution control equipment used to comply with this requirement is subject to Section II.B.2.

II.H.2.b. Beginning January 1, 2023, midstream segment owners or operators of midstream pipelines (not within the boundaries of the natural gas compressor station or natural gas processing plant) must use best management practices to reduce emissions from blowdowns, including, but not limited to, where practicable

II.H.2.b.(i) Planning for venting-reduction steps, such as pipeline pump-downs techniques (e.g., in-line compressors, portable compressors, ejector), when large vessels and pipelines need to be isolated and depressurized.

II.H.2.b.(ii) Rerouting gas to the low-pressure system using existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems.

II.H.2.b.(iii) Minimizing the volume that must be released. For example, add stops to isolate a smaller section of a pipeline to reduce the length of pipe that must be vented.

II.H.2.b.(iv) Using inert gases and pigs to perform pipeline purges.

II.H.2.b.(v) Using hot taps to make new connections to pipelines to avoid the need to depressurize the pipeline.

II.H.2.b.(vi) Using non-intrusive inspection, such as inline inspection tools, to avoid the need to purge a pipeline prior to inspection.

II.H.2.b.(vii) Coordinating operational repairs and routine maintenance to minimize the number of emissions released.

II.H.3. Recordkeeping. The owner or operator must maintain records for a period of two (2) years and make them available to the Division upon request, including

II.H.3.a. Records of pigging operations.

II.H.3.a.(i) The number of pigging events, including the locations of the pigging event, pigging facility (including AIRS ID, if applicable), and pigging pipeline; date and time; volume of gas recovered and released; type and volume of liquid cleared; and duration of emissions.

II.H.3.a.(ii) The monthly VOC and methane emissions associated with the pigging operations, in accordance with Division-approved calculation methodology, including the VOC and methane percent composition of the fluid transported by the pigging pipeline in percent VOC and methane by weight at normal pipeline operating conditions.

II.H.3.a.(iii) If subject to Section II.H.1.a., documentation of the methods used to comply with Section II.H.1.a.

I.H.3.a.(iv) If subject to Section II.H.1.b., documentation of best management practices employed pursuant to Section II.H.1.b.

II.H.3.b. Records of blowdowns.

II.H.3.b.(i) For blowdowns subject to Section II.H.2.a., the cause of blowdown emissions, including the location (by equipment, facility, and AIRS ID), date, time, and duration of emissions.

II.H.3.b.(ii) For blowdowns subject to Section II.H.2.b., the cause of blowdown emissions and the location (by equipment and coordinates if no AIRS ID), date, time, and duration of emissions.

II.H.3.b.(iii) The monthly VOC and methane emissions associated with blowdowns.

II.H.3.b.(iv) Records of best management practices employed pursuant to Section II.H.1.b.

II.I. (State Only) Control of emissions from natural gas-processing plants

II.I.1. Beginning January 1, 2023, owners or operators of natural gas-processing plants that are not subject to the requirements of Section I.G. must comply with the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOOa (June 3, 2016) unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOO (August 16, 2012).

II.I.1.a. The owner or operator must attempt drill and tap repair of leaking valves, if other repair methods are not successful, prior to placing the valve on delay of repair.

III. Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

III.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

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III.C. Emission Reduction Requirements

Owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

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III.C.3. (State Only) Statewide:

III.C.3.a. Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014, ~~and before May 1, 2021~~ except as otherwise provided in Section III.C.4., must~~:~~

III.C.3.a.(i) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible.

III.C.3.a.(ii) If on-site electrical grid power is not being used or a no-bleed pneumatic controller is not technically and economically feasible, utilize pneumatic controllers that emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.a.(iii) For purposes of Section III.C.3.a.(ii), instead of a low-bleed pneumatic controller, owners or operators may utilize a natural gas-driven intermittent pneumatic controller.

III.C.3.a.(iv) Utilizing self-contained pneumatic controllers satisfies Section III.C.3.a.(i).

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III.C.3.d. Continuous bleed, natural gas-driven pneumatic controllers located at natural gas-processing plants that are not subject to the requirements of Section III.C.2.

III.C.3.d.(i) All pneumatic controllers placed in service on or after January 1, 2023, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.3.a.(iii).

III.C.3.d.(ii) All pneumatic controllers with a bleed rate greater than zero in service prior to January 1, 2023, must be replaced or retrofit such that the pneumatic controller has a natural gas bleed rate of zero by January 1, 2024, unless allowed pursuant to Section III.C.3.a.(iii).

III.C.3.d.(iii) All pneumatic controllers with a natural gas bleed rate greater than zero that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.3.d.(iii)(A) For pneumatic controllers with a natural gas bleed rate greater than zero in service prior to January 1, 2023, the owner or operator must submit justification for pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2023.

III.C.3.d.(iii)(B) For pneumatic controllers with a natural gas bleed rate greater than zero placed in service on or after January 1, 2023, the owner or operator must submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

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III.C.4. (State Only) Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations

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III.C.4.e. Pneumatic Controllers That Emit Natural Gas to the Atmosphere Not Subject to Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations.

III.C.4.e.(i) Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements in Section III.C.4.a. and are not required to be retrofit in order to count the facility or controller as non-emitting for compliance with the company-wide plans under Sections III.C.4.c. and III.C.4.d.

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III.C.4.e.(i)(D) Pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices ~~and~~ or for artificial lift control located on a wellhead: (1) greater than one quarter mile from the associated production facilities for well production

facilities that commenced operation on or after May 1, 2021; or (2) not located on the same surface disturbance as the associated production facilities for well production facilities that commenced operation before May 1, 2021.

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III.D. Monitoring

This section applies to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

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III.D.4. (State Only) Located at a natural gas processing plants not subject to Section III.D.2.

III.D.4.a. Effective March 1, 2023, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.4.b. Effective March 1, 2023, the owner or operator must inspect each pneumatic controller with a natural gas bleed rate greater than zero on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

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III.F. (State Only) Pneumatic Controller Inspection and Enhanced Response

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III.F.2. Pneumatic controller inspection

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III.F.2.g. Beginning January 1, 2023, owners or operators of natural gas-driven pneumatic controllers located at natural gas-processing plants must inspect pneumatic controllers at, at least, the most frequent applicable LDAR monitoring frequency in 40 CFR Part 60, Subparts OOOO (August 16, 2012) or OOOOa (June 3, 2016) using an approved instrument monitoring method.

III.F.2.~~g~~h. Where detectable emissions from the pneumatic controller are observed, owners or operators must determine whether the pneumatic controller is operating properly within five (5) working days after detecting emissions. In making this determination, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.2.~~h~~i. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced response or follow manufacturer specifications to return the pneumatic controller to proper operation.

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III.F.5. Owners or operators of pneumatic controllers at well production facilities or natural gas compressor stations must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019 for facilities in the 8-Hour Ozone Control Area and May

31st, 2021, for facilities outside the 8-Hour Ozone Control Area) that includes, at a minimum, the following information regarding pneumatic controller inspection and enhanced response activities at their subject facilities conducted the previous calendar year.~~:~~

Owners or operators of pneumatic controllers at natural gas processing plants must submit the annual report on or before May 31st of each year beginning 2024.

III.F.5.a. The total number and type of pneumatic controllers returned to proper operation, the types of actions taken to return the pneumatic controllers to proper operation, and the facility type (by inspection frequency tier of well production facility or natural gas compressor station);

III.F.5.b. The number and type of pneumatic controllers on the delayed repair list as of December 31st broken out by the facility type (by inspection frequency tier of well production facility or natural gas compressor station), and the basis for each delay; and

III.F.5.c. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year.

~~III.F.6. The provisions in Section III.F. will be reassessed by the Division and stakeholders in 2020.~~

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V. (State Only) Oil and Natural Gas Operations Emissions Inventory

V.A. Applicability

V.A.1. On or before June 30th, 2021 (and on June 30th each year thereafter), the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.A.2. On or before June 30th, 2022 (and on June 30th each year thereafter), the owner or operator or class II disposal well facilities that are not subject to reporting under Section IV. must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.B. General reporting requirements

V.B.1. The following information must be reported in accordance with Section V.A.

V.B.1.a. Company name, physical street address, and name and contact information of the company representative, for reporting purposes.

V.B.1.b. The date of submittal and the year covered by the report.

V.B.1.c. A list of the activities or equipment, as specified in Section V.C., for which emissions are reported.

V.B.1.d. Beginning with the June 2022 report for calendar year 2021, owners or operators of well production facilities must submit a list of each well production facility, all associated wells by API number and associated location ID as reported to the Colorado Oil and Gas Conservation Commission.

V.B.1.~~d~~e. The company's monthly actual emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), nitrous oxide (N2O),

carbon dioxide (CO2), carbon monoxide (CO), methane, and ethane for each month of May through September, in accordance with Division-approved calculation methods.

V.B.1.~~e~~f. The company's annual actual emissions of VOCs, NOx, N2O, CO2, CO, methane, and ethane for the entire calendar year, in accordance with Division-approved calculation methods.

V.B.1.~~f~~g. The actual emissions of VOCs, NOx, N2O~~)~~, CO2, CO, methane, and ethane for each activity or equipment listed in Section V.C. per facility, or per pipeline between facilities where the pipeline is not located at a stationary source, in accordance with Division-approved calculation methods.

V.B.1.~~f~~g.(i) The report must include the actual emissions from each activity or equipment per month for each month of May through September.

V.B.1.~~f~~g.(ii) The report must include the actual emissions from each activity or equipment for the entire calendar year.

V.B.1.h. Beginning with the June 2022 report for calendar year 2021, if the emissions reported for any activities or equipment, as specified in Section V.C., are calculated using a method other than what would be used to report to the U.S. EPA under the federal Greenhouse Gas Reporting Program (40 CFR Part 98) for the same activity or equipment, the owner or operator must include in the report the emissions information reported to the EPA, an explanation of the difference in emissions reported to the Division, the emission calculation method(s) used to report to the Division, and a justification and supporting documentation for using a method other than that for the Greenhouse Gas Reporting Program. If the Division determines that the use of a different calculation method was not justified, the owner or operator must revise the report accordingly, to use the same calculation method as that reported under the federal Greenhouse Gas Reporting Program.

V.B.1.i. Emission factors, beginning with the June 22 report for calendar year 2021, where emission factors are used to calculate emissions reported pursuant to Section V.B.1.

V.B.1.i.(i) Owners or operators submitting reports under this section must use a Division-approved emission factor.

V.B.1.i.(ii) Owners or operators using a site-specific emission factor must submit documentation to the Division supporting the use of that emission factor.

V.B.1.i.(iii) Owners or operators using a site-specific emission factor must conduct a gas speciation analysis every three (3) years to verify the ongoing accuracy of the site-specific emission factor pursuant to a Division-approved sampling method or protocol.

V.B.1.~~g~~j. A certification by the company representative that supervised the development and submission of the inventory report that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

V.B.2. The owner or operator must submit a revised annual report after discovering that an annual report submitted within the previous two (2) years contained one or more substantive errors. A substantive error is a mass of emissions of any individual pollutant subject to reporting under Section V. that is at least 10% higher or lower than the mass of emissions of the pollutant reported across the owner or operator's activity or equipment,

as listed in Section V.C., in Colorado. A refinement of or improvement to an emissions estimation technique or emission factor is not a substantive error but must be noted in the subsequent annual report after the refinement or improvement. Revised annual reports must be submitted by August 31 if the substantive error is discovered between January 1 and June 30, and by February 28 if the substantive error is discovered between July 1 and December 31 of the preceding calendar year.

V.C. Beginning July 1, 2020, and each calendar year thereafter, owners or operators must maintain the following information for inclusion in the annual report, except that beginning January 1, 2021, owners or operators must maintain the information described in Sections V.C.2.g. and V.C.2.h. Beginning May 1, 2021, owners or operators of class II disposal well facilities must maintain the following information for inclusion in the annual report.

V.C.1. AIRS number of the activity or equipment and associated facility or pipeline (if a pipeline between facilities) location, including latitude and longitude coordinates. If the activity or equipment does not have an AIRS number, a description of the activity or equipment.

V.C.2. Actual emissions from each activity or equipment listed, unless otherwise specified in the Division-approved report format, and the emission factor(s), assumptions, ~~and~~ calculation methodology used to calculate the emissions, and other supporting information on the Division-approved form.

V.C.2.a. Abnormal events, except those reported as malfunctions under the Common Provisions or in another activity or equipment.

V.C.2.b. Acid gas removal units.

V.C.2.c. Associated gas venting and flaring, aggregated per facility. Beginning with the June 2023 report for calendar year 2022, owners or operators must measure or estimate the volume of natural gas that is vented or flared during drilling, completion, and production operations.

V.C.2.d. Blowdowns from facility equipment piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet, aggregated per activity below per facility. Beginning with the June 2024 report for calendar year 2023, owners or operators must report this information for all blowdowns from facility equipment and piping, even where the physical volume between isolation valves is less than 50 cubic feet.

V.C.2.d.(i) Pipeline venting within the facility boundary.

V.C.2.d.(ii) Compressors.

V.C.2.d.(iii) Scrubbers/strainers.

V.C.2.d.(iv) Pig launchers and receivers, through the June 2022 report for calendar year 2021.

V.C.2.d.(v) Emergency shutdowns (regardless of equipment type).

V.C.2.d.(vi) ~~All~~ Until the June 2024 report for calendar year 2023, all other equipment (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) with a physical volume between isolation valves greater than or equal to 50 cubic feet.

V.C.2.d.(vii) Beginning with the June 2024 report for calendar year 2023, all other equipment (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels), regardless of the physical volume between isolation valves.

V.C.2.d.(viii) Beginning with the June 2024 report for calendar year 2023, best management practices employed pursuant to Section II.H.2.b, per blowdown event.

V.C.2.e. Boilers.

V.C.2.f. Centrifugal compressor leaks or vents, aggregated per facility.

V.C.2.g. Class II disposal well facility fluids accepted for injection. Owners or operators will take periodic, representative samples of the liquids for estimating emissions for the annual report.

V.C.2.h. Class II disposal well facility produced water ponds.

V.C.2.i. Drilling mud and mud pits.

V.C.2.j. Flares and enclosed combustion devices, where not otherwise reported in the emissions of another emissions source category.

V.C.2.k. Fugitive emissions from components, aggregated per facility. Beginning with the June 2022 report for calendar year 2021, gas composition data and component counts used in fugitive emissions calculations must be provided.

V.C.2.l. Hydrocarbon liquid storage tanks.

V.C.2.m. Hydrocarbon liquid loadout.

V.C.2.n. Maintenance and safety, where not otherwise reported in the emissions of another emissions source category. Beginning with the June 2023 report for calendar year 2022, owners or operators must report the basis for each maintenance or safety event.

V.C.2.o. Natural gas dehydration (glycol and desiccant).

V.C.2.p. Natural gas pneumatic controllers, aggregated per facility. Pneumatic controllers at the wellhead must be aggregated with the associated facility.

V.C.2.q. Natural gas pneumatic pumps, aggregated per facility. Pneumatic pumps at the wellhead must be aggregated with the associated facility.

V.C.2.r. Non-road internal combustion engines.

V.C.2.s. Pigging operations, including pig launchers and receivers. Beginning with the June 2023 report for calendar year 2022, emissions from pigging operations must be separately identified in the annual report from other operational activities.

V.C.2.s.(i) Beginning with the June 2024 report for calendar year 2023, capture or control technology or best management practices employed pursuant to Sections II.H.1.a. or II.H.1.b. per pigging event.

V.C.2.~~s~~t. Pipeline segments between facilities.

V.C.2.~~t~~u. Process heaters.

V.C.2.~~u~~v. Produced water storage tanks.

V.C.2.~~v~~w. Produced water loadout.

V.C.2.~~w~~x. Reciprocating compressor leaks or vents, aggregated per facility.

V.C.2.~~x~~y. Separators (e.g., two-phase separators, three-phase separators, high/low pressure separators, heater-treaters, vapor recovery towers, etc.). Beginning with the June 2022 report for calendar year 2021, stages of separation must be identified.

V.C.2.~~y~~z. Stationary combustion turbines.

V.C.2.~~z~~aa. Stationary compression ignition internal combustion engines.

V.C.2.~~aa~~bb. Stationary spark ignition internal combustion engines.

V.C.2.~~bb~~cc. Temporary completion and/or workover equipment (e.g., tanks).

V.C.2.~~cc~~dd. Thermal oxidizing units, where not otherwise reported in the emissions of another emissions source category.

V.C.2.~~dd~~ee. Well completions (includes flowback).

V.C.2.~~ee~~ff. Well workovers.

V.C.2.~~ff~~gg. Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

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VI.C.2. Recordkeeping and reporting

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VI.C.2.b. Owners or operators must submit monthly reports of monitoring conducted to the Division by the last day of the month following the previous month of monitoring (e.g., by June 30 for the previous May 1-31), including

VI.C.2.b.(i) The month and year of the monitoring period.

VI.C.2.b.(ii) A description of the monitoring equipment and the pollutant(s) monitored.

VI.C.2.b.(iii) A description of the monitored operations including

VI.C.2.b.(iii)(A) The phase of operation (e.g., prior to pre-production, during pre-production operations, early production) and activities occurring during the monitored period.

VI.C.2.b.(iii)(B) API number of the well(s).

VI.C.2.b.(iii)(C) Location of the operations, including latitude and longitude coordinates.

VI.C.2.b.(iii)(D) Any associated facility or equipment AIRS number(s).

VI.C.2.b.(iii)(E) The date, time, and duration of any monitoring equipment downtime.

VI.c.2.b.(iii)(F) The date, time, and duration of operations malfunctions and shut-in periods or other events investigated for influence on monitoring.

VI.C.2.b.(iv) For the first monthly report after beginning monitoring during pre-production operations, a summary of air quality condition results monitored prior to beginning pre-production operations, including time series of the results at hourly or higher time resolution and a statistical summary of the air quality results monitored prior to beginning pre-production operations, including number of observations, maximum concentrations or levels, periodic averages, and data distributions including 5th, 25th, median, 75th and 95th percentile values.

VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5th, 25th, median, 75th and 95 percentile values.

VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.

VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.

VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.

VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.

VI.C.2.b.(x) Beginning May 2023, a list of leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak pursuant to Section II.E.

VI.C.2.b.(xi) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

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PART F Statements of Basis, Specific Statutory Authority, and Purpose

X. Adopted: December 17, 2021

Revisions to Part D, Sections II., III., V., and VI.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-110 and 25-7-110.5., C.R.S., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

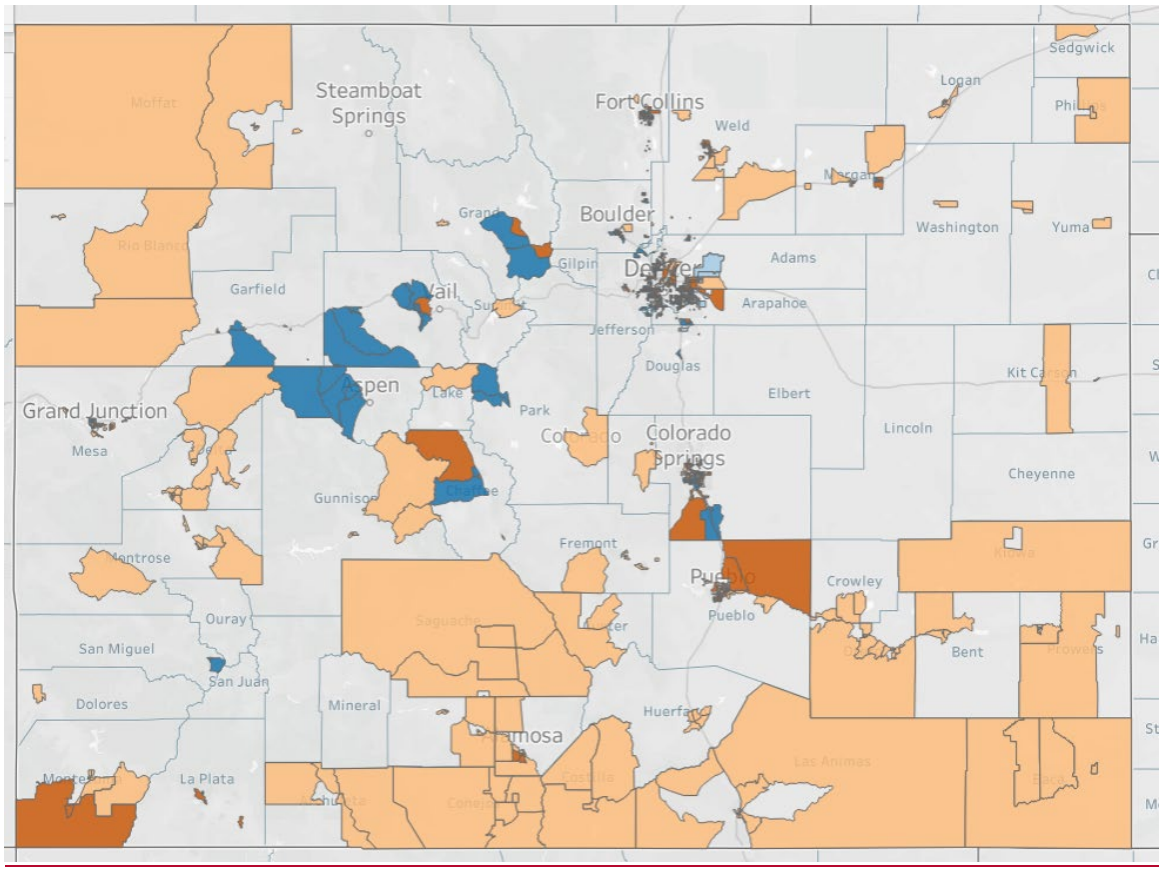
During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the Air Quality Control Commission. Further, the General Assembly declared in House Bill 19-1261 (HB 19-1261) that "climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "many of these impacts disproportionately affect" certain disadvantaged communities. Colorado's statewide greenhouse gas (GHG) reduction goals seek a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels.

In October 2020, the Commission established a target for the O&G Sector of a 36% reduction from the 2005 baseline by 2025 and a 60% reduction from the 2005 baseline by 2030 (an estimated 13 million metric tons (MMT) CO2e by 2025 and 8 MMT CO2e by 2030). Commission targets for the sector including residential, commercial, and industrial combustion emissions (RCI Sector) seek a 20% reduction from 2005 numbers by 2030. House Bill 21-1266 (HB 21-1266), signed into law on July 2, 2021, memorializes percentage reductions in statute, and provides additional requirements for the rulemakings to achieve these goals. The GHG Pollution Reduction Roadmap ("GHG Roadmap") developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the baselines from which these reduction percentages are to be estimated. The oil and gas industry is a large source of GHG emissions, and the largest anthropogenic source of methane in Colorado. For the oil and gas industry, not all of its emissions are found in the "O&G Sector", also referred to as the "Oil & Gas Fugitive Emissions" category of the GHG Roadmap. Methane emissions from upstream and midstream activities, along with estimates of methane "leakage" from pipelines in the transmission & storage and distribution segments, are in the O&G Sector. In contrast, most of the emissions from fuel combustion at oil and gas sources in the upstream and midstream segments are actually found in the "RCI Sector" of the GHG Roadmap (specifically in the "industrial" category, which is the subject of new HB 21-1266).

In this rulemaking action, the Commission has adopted requirements for upstream and midstream segment operations, to reduce GHG emissions from those operations, sufficient - when taken in combination with other regulatory and voluntary actions across the state - to achieve the GHG reduction requirements of HB 21-1266. The Commission did not adopt regulations applicable to the transmission and storage segment or the distribution segment. With regard to the transmission and storage segment, the Commission adopted a performance-based program for this segment in 2019 designed to materially reduce greenhouse gas emissions from transmission and storage operations; reporting of progress has not yet begun under that program and the Commission believes it reasonable to evaluate the progress of that program before modifying it. The Commission did not adopt regulations applicable to the distribution segment because legislation passed in the 2021 session invests the Colorado Public Utility Commission (PUC) with authority over this segment of the oil and gas industry. SB 21-264 requires that gas distribution utilities will submit a comprehensive clean heat plan that demonstrates projected reductions in methane and carbon dioxide emissions that meet prescribed reduction targets. Each clean heat plan must outline the utility's proposal to reduce carbon dioxide and methane emission levels by 4% in 2025 and 22% in 2030. Gas distribution utilities, depending on their size, must submit clean heat plans to the PUC by August 1, 2023, and January 1, 2024. Thus, the Commission believes that the transmission & storage performance program and the clean heat plans are likely to achieve reductions of emissions necessary from these segments to achieve the goals of §25-7-105(1)(e)(XII).

In the 2021 legislative session, in HB 21-1266, the General Assembly determined that "state action to correct environmental injustice is imperative, and state policy can and should improve public health and the environment and improve the overall well-being of all communities… [and] efforts to right past wrongs and move toward environmental justice must focus on disproportionately impacted communities and the voices of their residents." HB 21-1266 also requires the Commission to ensure that there are additional

protections for, and reductions of co-pollutants in, disproportionately impacted communities. CDPHE developed a map of the disproportionately impacted communities that meet the definition of HB 21-1266. While this map is expected to change over time, the disproportionately impacted communities that have been identified at the time of this program's adoption are as set forth in the following map:



Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq. (the State Air Act or the Act), specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere and provides the Commission broad authority to regulate air pollutants.

Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations

Pursuant to HB 21-1266, the Commission must, by January 1, 2022, adopt regulations to ensure that the state meets its greenhouse gas reduction targets for the oil and gas sector (36% by 2025 and 60% by 2030). The Commission must also ensure that industrial sector emissions (including those from oil and gas fuel combustion equipment) are reduced by 20% from the 2015 baseline by 2030. These revisions to Regulation Number 7 will, taking into account other relevant laws and rules (including the revisions to Regulation Number 22 adopted as part of this rulemaking action), as well as voluntary actions taken by local communities and the private sector, achieve the state's GHG reduction goals through 2030 for the oil and gas industry. The revisions include protections for disproportionately impacted communities that ensure reductions of pollutants other than GHGs, additional requirements for monitoring and leak

detection and repair, and improve the state's current emission inventory reporting program in Regulation Number 7, Part D, Section V.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, Part D, and includes the technological and scientific rationale for the adoption of the revisions.

Definitions: Section II.A.

The Commission has adopted definitions for new terms to facilitate implementation of the new regulatory program. Where these terms are also proposed for definition in Regulation Number 22, these explanations are intended to address both regulations.

The Commission has revised the definition of Approved Instrument Monitoring Method (AIMM) to clarify that when the Division approves an alternative AIMM, the Division's approved AIMM may address both AIMM and AVO leak inspections.

The Commission has defined "disproportionately impacted community" consistent with the definition in HB 21-1266. However, the statute does not specifically identify which communities are considered disproportionately impacted. CDPHE is developing a tool, called "enviroscreen" that will be utilized for members of the public and the regulated community to understand which communities in Colorado are disproportionately impacted. However, this tool was not ready at the time of this rulemaking. Therefore, the Commission has determined that the disproportionately impacted communities existing at the time of adoption of this program, and therefore the communities in which provisions of this program apply, are identified in the map above.

The Commission defined "midstream segment", "natural gas processing segment", "natural gas transmission and storage segment" and "oil and natural gas compression segment" in this regulation to be consistent with definitions in other regulations, including Regulation Number 7, Part D, Section IV. and Regulation Number 22, Part B, Sections III. and IV.

Air Pollution Control Equipment: Section II.B.

The Commission established updated maintenance and performance test requirements for air pollution control equipment in Section II.B.

In Section II.B.2.f., the Commission set forth the weekly visual inspections required for all air pollution control equipment used to comply with Section II. In this context, the Commission intends "weekly" to mean every seven calendar days. These requirements - as they applied to air pollution control equipment controlling storage tanks - were previously located in Section II.C.1.d. of this regulation (in Section II.C.1. and II.C.3., the Commission repealed these provisions that moved to Section II.B.2.); however, to ensure requirements for air pollution control equipment were in one location, the Commission has repealed the provisions of Section II.C.1.d. that are now found in Section II.B.2.f. The Commission does not intend that there is any period of time where air pollution control equipment is not subject to either Section II.C.1.d. or II.B.2.f.

Section II.B.2.g. requires owners and operators to install and operate a flow meter at the inlet to air pollution control equipment covered by this section, with some exceptions. A flow meter is a device that measures the amount of gas entering the enclosed combustion device and can be used to help determine whether an enclosed combustion device is functioning properly. The Commission believes that flow meters are an important tool to help the Division ensure that air pollution control equipment achieves at least 95% control efficiency for hydrocarbons. Flow meters also provide valuable information to help the Division verify the emission calculations for this equipment reported under Regulation Number 7, Part D, Section V. In Section II.B.3.g.(iii)(C), the Commission recognizes that the use of flow meters may not always be feasible; for example, flow meters can be less effective where the control device is a "low flow" device - i.e. where the flow to the device is not consistent or high enough to achieve generally accurate readings from the meter. The Commission encourages operators to provide alternative mechanisms for tracking flow data to air pollution control equipment for those situations in which flow meters are less efficient or accurate.

In Section II.B.2.h., the Commission established performance testing requirements for enclosed combustion devices. Truly voluntary control equipment is not subject to these provisions. Historically, the Commission has assumed that enclosed combustion devices were achieving at least 95% control efficiency for hydrocarbons. However, the Commission determined that it was appropriate to promulgate regulatory requirements that will additionally ensure that enclosed combustion devices in the state are, in fact, operating at and achieving 95% control efficiency for hydrocarbons. Section II.B.2.h.(ii)(A) contains a table that sets forth the schedule for the initial testing of enclosed combustion devices that commenced operation before December 31, 2021 (unless the Division approves an alternative testing schedule). The Commission prioritized the testing of ECDs in disproportionately impacted communities and, after that, devices in the 8-hour Ozone Control Area/northern Weld County. Some stakeholders wanted the Commission to formally adopt these requirements as part of expanding the nonattainment area boundary for the 2015 ozone NAAQS; however, at the time of the proposal for this regulation, the state was still waiting on final action from the U.S. EPA, and such a change must be accomplished in the state implementation plan, not in Section II of Regulation Number 7, Part D, which contains state-only requirements.

The Commission strongly encourages owners and operators to prioritize the testing of the enclosed combustion devices at the biggest sites and the oldest enclosed combustion devices. The Commission believes that underperforming, older enclosed combustion devices at large sites could be responsible for a larger portion of uncontrolled emissions and, therefore, such devices should be identified sooner rather than later in order to more effectively limit the amount of uncontrolled emissions. In addition, the Commission believes that, due to their age, older enclosed combustion devices are more likely to malfunction and, therefore, underperform than newer enclosed combustion devices. Thus, the Commission believes that a greater amount of uncontrolled emissions could be avoided by prioritizing the testing of higher capacity or older enclosed combustion devices, especially those in DI communities. However, the Commission also recognizes that older enclosed combustion devices may not have been manufactured or installed with appropriate ports for traditional stack test methods, which will affect timing for performance testing where modifications to existing equipment must first be made. Such considerations should be included as operators develop schedules to perform required testing.

With regard to the testing schedule and other testing deadlines set forth in Section II.B.2.h.(ii) (see, for example, Section II.B.2.h.(ii)(C)), an enclosed combustion device that is relocated by an owner or operator to another facility that is also controlled by that same owner or operator may maintain the same testing schedule as if it had not been relocated.

Section II.B.2.h.(iii) provides that owners or operators of enclosed combustion devices subject to Section II.B.2.h.(ii) must submit a notification to the Division with certain specified information no later than July 31, 2022. Such notification must be submitted in writing and may be amended as long as the testing schedule set forth in Section II.B.2.h.(ii) is met. Section II.B.2.h.(iii)(A) identifies some of the specific information that must be included in the notification, including the location of the enclosed combustion device. When providing the location of the enclosed combustion device in a written notification, the owner or operator must also state whether or not the enclosed combustion device is located within a DI community and/or the 8-hour Ozone Control Area/northern Weld County.

The Commission has determined that performance tests must be conducted pursuant to a Division-approved protocol. The Commission intends that as an alternative to a site-specific protocol, operators may submit to the Division a company-specific protocol for approval for that company's different types of site configurations, to which an operator would certify that it followed for each performance test conducted pursuant to that protocol. The Commission also anticipates that the U.S. EPA will be releasing a protocol for an outlet-only testing method; the Division is directed to consider publishing that protocol on its website as a pre-approved test protocol for ECD performance testing, to which operators would certify they followed in conducting a performance test. The Division may also develop a statewide protocol that may be followed by any owner or operator. If utilizing the Division's statewide protocol, an owner or operator need only provide a notice prior to conducting testing pursuant to the protocol. The Commission also directs the Division to consider approving different protocols for different types of devices. For example, the Commission would support a different test protocol for devices operating at such low-flow that supplementing the gas stream to the device would be required for purposes of the test.

In Section II.B.2.h.(i)(D), the Commission explained how operators should use the results of the performance test in calculating emissions for purposes of the annual emissions inventory reporting under Sections II.G and V. If a performance test is conducted on June 1, and the ECD fails the test, and a retest is conducted on July 1, and the ECD passes the test, the operator should use the results of the failing

performance test for emission calculations from January 1 through June 30, and the results of the passing performance test from July 1 through December 31 of that year.

In Section II.B.2.i and j, the Commission established recordkeeping and reporting requirements. The Commission deferred most of the reporting to the annual emission reports in Section V, but did require some additional reporting. When an ECD fails its performance test, the Commission believes it is critical that the Division be made aware as soon as possible, and so has required notification be provided within fourteen (14) days of a failing test.

Rod packing at natural gas processing plants: Section II.B.3.

In 2014, the Commission recognized that rod-packing replacement is an effective, and cost-effective, method for reducing emissions from this equipment - both VOC and other hydrocarbons. However, the Commission's 2014 action applied only to reciprocating compressors at compressor stations, and not gas plants. In 2017, the Commission adopted rod-packing replacement requirements for compressors at gas plants in the 8-hour Ozone Control Area. In this rulemaking, in Section II.B.3., the Commission expands rod packing replacement requirements to natural gas processing plants statewide except where the reciprocating compressor is subject to the rod packing requirements of NSPS OOOO or NSPS OOOOa. Under these revisions, beginning upon the effective date, anticipated for February 14, 2022, operators will need to track hours of operation for purposes of compliance.

In Section II.B.3.c., the Commission clarified that the rod packing requirements adopted in 2014 did not apply where the compressor was subject to the reciprocating compressor requirements of NSPS OOOO. The revision to specifically identify the rod packing requirements was not a change to the meaning of the provision.

Leak Detection and Repair: Sections II.E. and II.I.

Section II.E. of Regulation Number 7 establishes additional requirements under the leak detection and repair (LDAR) program for well production facilities and natural gas compressor stations. In 2014, 2017, and in 2019, the Commission established LDAR inspection frequencies to identify leaking components and require repairs in a timely fashion to eliminate excess emissions. LDAR inspection frequencies are typically based on the rolling twelve-month tons per year fugitive VOC emission rates of well production facilities and compressor stations and their location.

In 2019, the Commission adopted more stringent inspection and repair requirements for well production facilities in proximity to an occupied area. In this rulemaking action, the Commission increased the frequency of inspections at compressor stations and well production facilities in disproportionately impacted communities (see map above for the specific communities in which these requirements apply). The Commission has determined that faster repair schedules and additional monitoring is required to protect public health and the environment within these disproportionately impacted communities.

In Section II.E.4.f., the Commission has set a static frequency of AIMM inspections for newly constructed well production facilities - regardless of emissions. That is, any newly constructed well production facility will have a monthly AIMM inspection frequency. The Commission does want to encourage the use of alternative technologies, rather than just the traditional infrared (IR) camera. Technological advances in leak detection can outpace regulations. The Commission expects that many new technologies can be approved through the Division's existing alternative AIMM review process. The Commission does note, however, that some alternative AIMM may be appropriate for statewide inspection requirements, but not to supersede SIP inspection requirements (e.g., requirements of Regulation Number 7, Part D, Section I.L.). The Commission encourages the Division to consider, where appropriate, approving technologies as alternative AIMM for purposes of this Section II.E even where the technology may not be approvable as alternative AIMM for Section I.L. The Commission has also recognized two scenarios where new well production facilities need only comply with Table 4 (formerly, Table 3) frequencies and need not conduct monthly AIMM inspections. These scenarios include: 1) where the operator installs and uses systems to continuously monitor and adjust pressures in the storage tanks to prevent venting and to ensure lit pilot lights; and 2) where the operator continues operation of its air quality monitoring plan approved under Regulation Number 7, Section VI., for VOC or methane. For the former, the Commission directs the Division to issue a protocol for the use of these automated systems, based on the Division's work in evaluating closed loop vapor control systems. For both scenarios, if an operator were to cease using either of these scenarios, the facility would revert to a monthly AIMM schedule.

In Section II.I, the Commission determined that natural gas processing plants state-wide must now have LDAR programs consistent with NSPS OOOO or OOOOa, rather than just the gas plants in the 8-hour Ozone Control Area.

Separator Control Requirements: Section II.F.

Section II.F had previously required capture or control of hydrocarbon emissions from separation equipment for a well-constructed, fracked, or recompleted after 2014; in this revision, the Commission required the capture or control of hydrocarbon emissions from all separation equipment, regardless of construction date. This is consistent with the recent Colorado Oil and Gas Conservation Commission (COGCC) mission change rulemaking, which essentially requires capture and prohibits the venting or even flaring of gas from the separation equipment unless a variance is obtained from the COGCC. Where the COGCC determines that a variance for venting (as that term is defined by the COGCC) is appropriate, that operation is exempt from this Section II.F.2. of the Commission's regulation (though not from Section II.F.1. or other applicable provisions, such as Regulation Number 3 reporting and permitting or Regulation Number 7, Part D, Section V. annual emission reporting).

Further, Section II.F. was revised to clarify that all control equipment controlling separators is subject to Section II.B.2. requirements (separators subject to Section II.F were already subject to II.B.1.).

Well Maintenance Requirements: Section II.G.

Certain activities - such as well liquids unloading, well maintenance events, and well plugging - can result in emissions to the atmosphere. The Commission has long required that operators use best management practices to reduce the need to emit during these activities, and to reduce the amount of gas emitted during these activities. However, the Commission has determined that it is necessary to specify some of the practices that must be employed. Section II.G. therefore identifies several best management practices that operators must use to reduce the need for emissions from all these activities. For example, the Commission intends that in constructing a new well production facility, operators must consider how to reduce the need for well liquids unloading or well maintenance over the life of the well, and design accordingly.

The Commission also recognizes that well unloading occurs to remove liquid build-up to restore productivity. When attempting to relieve atmospheric pressure through emitting to the atmosphere to remove liquid buildup in these wells, particularly when the emissions occur multiple times each year over the life of a well, there can be significant hydrocarbon emissions. The Commission considers well swabbing to be a well liquids unloading event. Technology and practices have advanced such that it is possible to use equipment - including equipment more typically considered process equipment - to reduce the need to emit during well liquids unloading. For example, the use of an artificial lift, such as a plunger lift, can both reduce the need to emit during well liquids unloading and reduce the volume of gas emitted during a manual liquids unloading event.

Pigging and Blowdown Requirements: Section II.H.

The Commission was presented with data reported to EPA and to the Division that generally agrees that the largest sources of greenhouse gas emissions from the midstream segment is the fuel combustion equipment; however, these data sets also agree that emissions (particularly methane emissions) from operations and maintenance activities - such as pigging and blowdowns - are significant, and, the Commission has determined they are cost-effective to address. The Commission recognizes that depressurizing pig launchers and receivers in natural gas gathering operations can emit volatile organic compound (VOC) emissions. This gas released from pigging activities is under the same pressure as the pipeline and contains methane, ethane, and VOCs including benzene, toluene, ethylbenzene, and xylene. Pig receivers can also contain collected condensate liquid that had accumulated in the pipeline.

The Commission mandated that owner/operators capture and recover gas from pigging activities, and if not possible, to request Division approval to install and operate air pollution control equipment, such as vapor recovery, flare/combustors, or a Division-approved alternative to achieve a 95% reduction in hydrocarbon emissions. The requirement to capture or control hydrocarbon emissions associated with pigging operations applies when the operator - across all its operations, not just at one facility - conducts pigging operations more than 12 times per year. Where capture and control are not required, the Commission directs operators to use best management practices to reduce emissions from pigging. The Commission understands from operators that design techniques can minimize the frequency of pigging

and the volume of gas emitted during pigging. Because the value of the specific BMPs identified by the Commission may change depending on future design considerations, the Commission has authorized the Division to approve alternatives that achieve equal to or better emission reductions. The Division can issue one or more guidance documents with pre-approved alternatives as understanding of pigging emissions and technologies and practices to reduce them improve.

The Commission mandated recordkeeping and reporting requirements in Sections II.H.3.a. and V. applicable to pigging operations to ensure compliance with and to track the efficacy of the established emission reduction measures. Emissions from pigging must be included in Regulation Number 7, Part D, Section V. annual reports.

In Section II.H.2., the Commission established that midstream segment owners or operators must capture or control hydrocarbon emissions from blowdowns at natural gas compressor stations and natural gas processing plants. For blowdowns along midstream pipelines - where not located within the boundaries of a natural gas compressor station or gas plant - the Commission determined it was appropriate to require the use of BMPs. The Commission does not intend that operators will use each BMP during every midstream pipeline blowdown event, but does intend that these BMPs be used where practicable.

The Commission also updated Section II.C.2.a. and III.C. to reflect that the “operate without venting” mandate, and associated recordkeeping, applies during pigging and blowdown activities where reductions are required. The venting from storage tanks resulting from these operations and maintenance activities at midstream operations are no longer automatically assumed to be appropriate or necessary.

In addition to the recordkeeping and reporting requirements applicable to pigging events, the Commission also required records of blowdowns. The records must outline the cause of blowdowns, the location, date, time, and duration of the emissions and records of best management practices employed to capture or control these blowdown emissions.

Pneumatic Controller Revisions: Section III.

The rule also expands the applicability of controller requirements and inspection and enhanced response requirements state-wide to natural gas processing plants. The Commission’s proposal would require new gas plants to install, and existing gas plants to retrofit natural gas driven controllers with, zero-bleed controllers, unless certain safety exemptions are met. The Commission’s proposal also requires that any remaining gas-driven controllers be subject to the find and fix program.

In Section III.C.3.a., the Commission clarified a revision made in February 2021. In February, the Commission revised this section to add an end-date of May 1, 2021, given the new requirements in III.C.4. However, the requirements of Section III.C.4. do not apply as widely as Section III.C.3.a., so the Commission here clarified that Section III.C.3.a. continues to apply unless a specific provision of Section III.C.4. is controlling (i.e., under the principle that the more specific controls over the general, in the event of a conflict between Section III.C.3.a. and III.C.4., Section III.C.4. would control).

Annual Emissions Reporting: Section V.

The Commission made several updates to Section V., some for clarification and some to better ensure the accuracy and verifiability of the annual emissions reports. In Sections V.B.1.e. through V.B.1.g., the Commission clarified that operators must use Division-approved calculation methods; the Commission considers this a clarification of the program adopted in 2019, which required operators to use the Division-approved form. The Commission adopted this clarification to ensure that operators are aware of the duty to recalculate and resubmit their annual emissions reports if the Division disapproves of a calculation methodology (if, for example, the methodology was not approved ahead of the report’s submission).

In Section V.B.1.h., the Commission expressly required that operators who submit emissions information using a calculation methodology different from that used to submit the annual greenhouse gas reports to the U.S. EPA under the Greenhouse Gas Reporting Program also submit to the Division: 1) the emissions information using the same calculation method as used in the GHGRP program; and 2) a justification for the change in calculation methodology. The Commission believes that flexibility in calculation methodology is an important tool to ensure more accuracy across operations; however, it is necessary to understand deviations from EPA’s approved methodology to ensure appropriate comparisons and to provide transparency. The Commission has also recognized again the Division’s authority to require

recalculation of emissions data if the alternative calculation methodology is not deemed approvable by the Division.

In Section V.B.1.j., the Commission has required that operators using emission factors to calculate emissions must either use Division-approved emission factors or may use a site-specific emission factor. However, the Commission recognizes that gas composition may change over time, and therefore has determined to require periodic gas composition analysis to support the continued use of site-specific emission factors. The Commission expects that the Division will, as appropriate, update any default factors based upon collected gas composition data.

In Section V.C.2., the Commission clarified the type of information that must be submitted. The requirements adopted in 2019 specified that operators must submit information including the emissions, emission factors, assumptions, and calculation methodology. And Section V.B.1.c. required submission of information about the activities and equipment covered by the report. The Commission now clarifies that other information the Division deems necessary to support the emissions reported must be included, to avoid operator reluctance to share this information based upon the previous regulatory language.

In Section V.C.2.d., beginning with the June 2024 report for calendar year 2023, the Commission requires owners or operators to report emissions, along with other supporting information, resulting from blowdowns from facility equipment and piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet. The Commission notes its interpretation that the 50 cubic foot exemption never applied to blowdowns of pipeline segments between facilities that were previously reported under Section V.C.2.s. (now Section V.C.2.t.). The Commission has also rearranged the requirement to report emissions and other supporting information for pigging operations such that it no longer falls under Section V.C.2.d. and now stands alone under Section V.C.2.s. The allowance to exclude blowdowns from facility equipment and piping as well as from pigging operations where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet continues through the June 2023 report for the 2022 calendar year. The Commission understands that accurate tracking of gas volumes from equipment and piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet can be difficult. Therefore, the Commission directs the Division to accept appropriate actual and approximated reported volumes for this subcategory of blowdowns.

In Section V.C.2.k., the Commission specified that operators must report component counts and gas speciation data used to support fugitive emission calculations. The Commission acknowledges that component counts can be representative, and are not necessarily specific counts per facility. However, where operators are using representative component counts, that must be noted on the submittal.

The Commission made other clarifications and updates, and included the date of both reporting year and year of report submittal where necessary to ensure that operators have adequate time to capture any new information.

Miscellaneous

In Section II.B.2. and II.B.3., the Commission updated the section regarding requirements for compressors (reciprocating and centrifugal) to reflect that compliance with either NSPS OOOO or NSPS OOOOa is sufficient.

The revisions made to Regulation Number 7 also renumber tables and provisions to accommodate the new requirements, and correct typographical, grammatical, and formatting errors.

Incorporation by Reference

The Commission will update regulatory references as needed as opportunities arrive.

Additional Considerations

The following are additional findings of the Commission made in accordance with the Act:

Section 25-7-110.5(5)(b), C.R.S.

As these revisions exceed and may differ from the federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) Any federal requirements that are applicable to this situation with a commentary on those requirements;

There are existing federal regulations that seek to identify and reduce methane emissions from the oil and gas industry, such as the Greenhouse Gas Reporting Program (Part 98) and NSPS KKK, OOOO, and OOOOa. The EPA will soon release proposals to address greenhouse gas emissions from oil and gas equipment, but EPA's proposal does not address the particular situations addressed by the Commission's revisions here.

Under Regulation Number 7, Part D, Section I.G, natural gas processing plants in the 8-hour Ozone Control Area must comply with the LDAR program in New Source Performance Standard (NSPS) OOOO or NSPS OOOOa. Natural gas processing plants outside the 8-hour Ozone Control Area may also be subject to NSPS OOOO or NSPS OOOOa, depending on the date of construction. In these revisions, the Commission subjected gas plants statewide to requirements that had previously only applied within the 8-hour Ozone Control Area. EPA also has regulations and guidance for compressors (e.g., rod packing replacement) and pneumatic controllers. Colorado's requirements - both existing and as proposed herein - meet or exceed these federal requirements. For example, many federal requirements are applicable in ozone nonattainment areas, while Colorado's provisions apply statewide.

Through Part D, as revised, the Commission builds upon established federal LDAR requirements and closes additional monitoring gaps by eliminating limits on NSPS OOOOa applicability by location for certain natural gas sources and to establish a more robust LDAR program throughout the state.

EPA also asks states to consider environmental justice as part of their actions, though there are no specific federal regulatory requirements at this time. In this revision, Part B, Sections III and IV expand on environmental justice considerations by incorporating the definition of "disproportionately impacted communities" (DI Community), and seeking to prioritize reductions in DI communities.

(II) Whether the applicable federal requirements are performance-based or technology-based and whether there is any flexibility in those requirements, and if not, why not;

The federal requirements addressing methane reductions from the oil and gas sector (though not applicable in this situation) as described above are both performance-based and technology-based. Current federal requirements for methane reductions speak to achieving a control efficiency, with minimal flexibility. Some requirements also mandate the use of technology to detect methane emissions; however, EPA does provide some flexibility in the technology that can be used.

(III) Whether the applicable federal requirements specifically address the issues that are of concern to Colorado and whether data or information that would reasonably reflect Colorado's concern and situation was considered in the federal process that established the federal requirements;

There are federal requirements that seek to reduce greenhouse gas from oil and gas operations, though none that are addressed to the specific goals of these revisions. The Commission's revisions address Colorado-specific requirements and needs, like those of HB 19-1261 and HB 21-1266, which were not considered in any federal process.

(IV) Whether the proposed requirement will improve the ability of the regulated community to comply in a more cost-effective way by clarifying confusing or potentially conflicting requirements (within or cross-media), increasing certainty, or preventing or reducing the need for costly retrofit to meet more stringent requirements later;

The proposed midstream and upstream requirements ensure that the regulated community can achieve required GHG emissions reductions in cost-effective ways and reduce the need for costlier retrofits later.

(V) Whether there is a timing issue which might justify changing the time frame for implementation of federal requirements;

This is a state-specific rule that is not implementing federal requirements. Thus, no timing issue exists with respect to implementation of federal requirements.

(VI) Whether the proposed requirement will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth;

The regulatory provisions allow a reasonable amount of time for affected entities to comply with the new revisions. As such, affected businesses or industrial sectors are afforded a reasonable margin for accommodation of uncertainty and future growth.

(VII) Whether the proposed requirement establishes or maintains reasonable equity in the requirements for various sources;

The Commission's revisions establish and maintain reasonable equity because they subject similar sources statewide with similar emitting activities to similar requirements. Climate change is not a local problem, and these rules demonstrate that the sources everywhere must contribute to the solution.

(VIII) Whether others would face increased costs if a more stringent rule is not enacted;

The Commission believes that the cost of inaction would be greater to industry and the public than the costs associated with the revisions to Regulation Number 7, Part D. Not only with respect to the social cost of climate change, but also more direct costs. These revisions are designed with the maximum flexibility for the regulated community. Under HB 21-1266, if the state is not on track to achieve the emission reduction goals, the Commission must adopt further regulations to achieve those goals. Future efforts are likely to be not as cost-effective as the flexible programs in these revisions.

(IX) Whether the proposed requirement includes procedural, reporting, or monitoring requirements that are different from applicable federal requirements and, if so, why and what the "compelling reason" is for different procedural, reporting, or monitoring requirements;

Reporting requirements beyond those required under federal Part 98 are necessary to effectively quantify and measure Colorado's progress toward statewide GHG reductions and to achieve the public health, safety, and welfare goals set forth in Section 25-7-102, C.R.S. Many of the reporting requirements associated with these programs are in existing Commission regulations, in Regulation Number 7, Part D. However, these revisions do require some additional reporting. Under these requirements, owners and operators of these sources will be required to compile and report directly to the Division information collected by or available to them for business or other regulatory purposes. While this may overlap with some other federal reporting requirements, it is expected there will be reporting beyond what is required federally.

(X) Whether demonstrated technology is available to comply with the proposed requirement;

Demonstrated technology exists to enable compliance with the requirements of these revisions. The Commission has also embedded maximum flexibility to take advantage of future technological developments.

(XI) Whether the proposed requirement will contribute to the prevention of pollution or address a potential problem and represent a more cost-effective environmental gain;

These revisions will cost-effectively reduce statewide GHG emissions to meet the legislative directive of the State Air Act, as revised by SB 19-181, HB 19-1261, and HB

21-1266. As noted above, the General Assembly has acknowledged that climate change impacts Colorado's economy and directed that GHG emissions should be reduced across the many sectors of our economy. Colorado has established specific GHG reduction goals within its statutes. Programs established in this rulemaking action - in both Regulation Numbers 7 and 22 - provide mechanisms for GHG reductions to occur cost-effectively across a specific, high-emitting sector of the state's economy.

(XII) Whether an alternative rule, including a no-action alternative, would address the required standard.

The new regulatory requirements and amendments are needed to achieve the statutorily mandated emission reductions. As noted above, the State Air Act requires the Commission to implement GHG emission reduction strategies in order to secure reductions of pollution consistent with the statewide GHG emission reduction goals. Currently, emissions projections over the next decade demonstrate that a no-action alternative would fall short of achieving Colorado's reduction goals. Additionally, no alternative combination of sector-specific regulations has been identified that is sufficient to meet the state's GHG emissions reductions goals.

Findings of Fact

To the extent that § 25-7-110.8, C.R.S., requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of greenhouse gas and VOC emissions.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary reduction in air pollution and provide the regulated entity flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.